Required reading for the Global Oil & Gas Industry since 1975

OE

oedigital.com

EPIC
Transport & Installation **32**

SUBSEA
All-Electric **38**

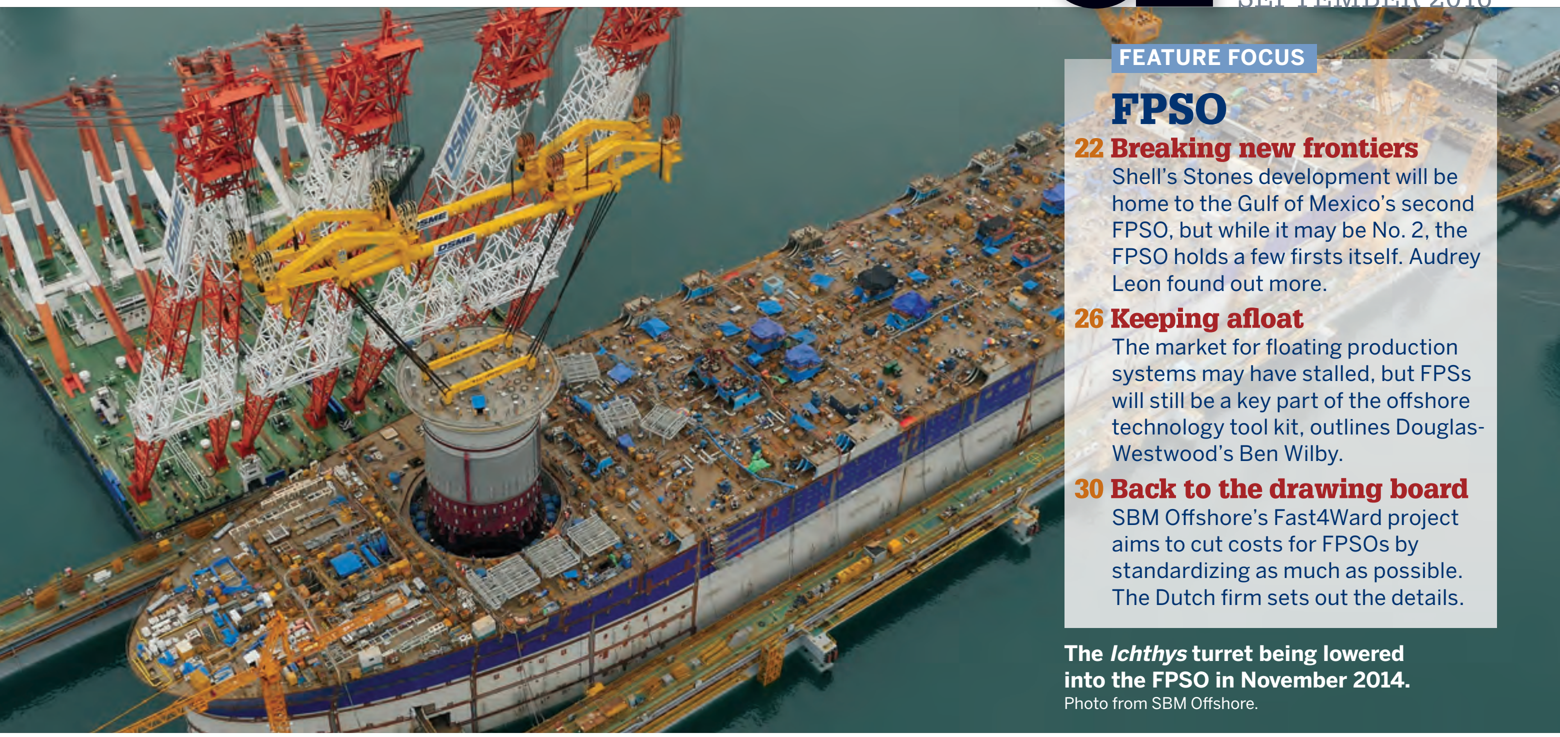
AUTOMATION
High-Tech Fields **50**

FPSOs

- Making history in the Gulf 22
- Market outlook 26
- Standardization 30

Offshore Engineer • September 2016


We're reshaping subsea design. For the better.
PLEM
ETH
Rethink. Reinvent. Reimagine.
We created our new Forsys Subsea joint venture with Technip specifically to simplify field architectures and lower costs. The key: Early involvement in concept selection, when making the right choices can lower costs the most. By reducing design complexity we can consistently cut CapEx and OpEx. It's a totally new way to design, deliver and operate subsea fields, for life – and the best way to find the lower break-even costs you need in today's market.
© FMC Technologies, Inc. All Rights Reserved.
www.fmctechnologies.com
#RethinkReinventReimagine
FMC Technologies
We put you first.
And keep you ahead.



FEATURE FOCUS

FPSO

The *Ichthys* turret being lowered into the FPSO in November 2014.
Photo from SBM Offshore.

Features

ON THE COVER

Any day now. ***OE***'s September cover features the *Turritella* FPSO, which will be deployed at Shell's Stones development in the US Gulf of Mexico. The vessel has been on location since December, and start-up should occur by year's end. *Photo courtesy of Shell.*

IMAGINE

TAKING YOUR WORK PROCESSES DIGITAL

The ultimate PDF-based markup and collaboration solution, Bluebeam® Revu® includes customizable annotation and reporting tools for P&IDs and other drawing types. Save time and improve project communication throughout key work processes, including drawing reviews, line walks, test packs and shutdowns.

Download a 30-Day Trial Today!
bluebeam.com/clarify

bluebeam®
A NEMETSCHEK COMPANY

No Limits®

© Copyright 2016 Bluebeam Software, Inc.

Departments & Columns

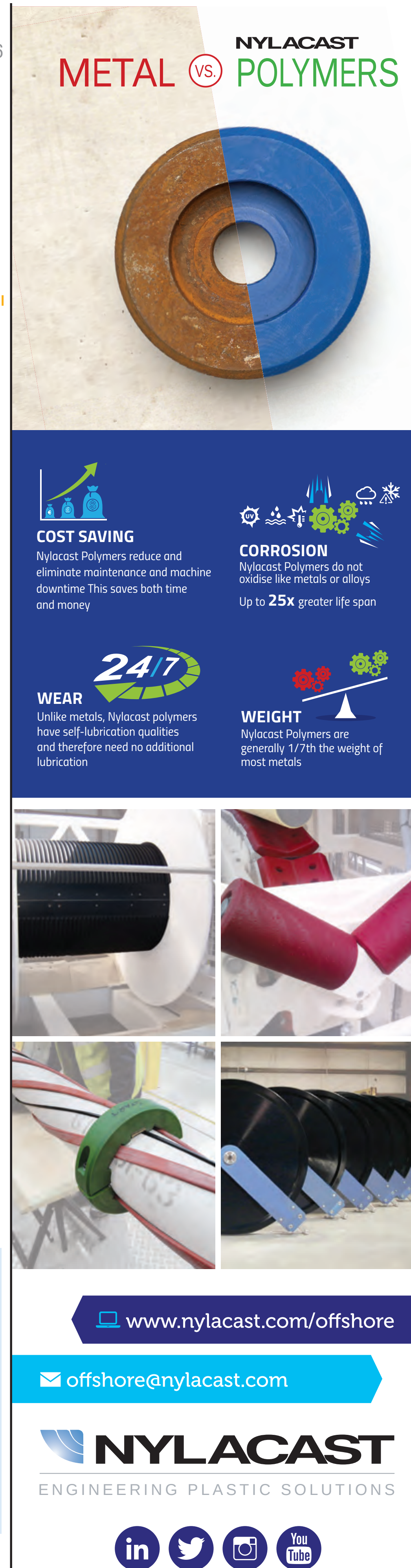
ATCOmedia
Atlantic Communications Media

OE (Offshore Engineer) is published monthly by AtComedia LLC, a company wholly owned by IEI, Houston. AtComedia also publishes **Asian Oil & Gas**, the **Gulf Coast Oil Directory**, the **Houston/Texas Oil Directory** and the web-based industry sources **OilOnline.com** and **OEDigital.com.**

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

US POSTAL INFORMATION
Offshore Engineer (USPS 017-058) (ISSN 0305-876X) is published monthly by AtComedia LLC, 1635 W. Alabama, Houston, TX 77006-4196. Periodicals postage paid at Houston, TX and additional offices.
Postmaster: send address changes to Offshore Engineer, AtComedia, PO Box 47162, Minneapolis, MN 55447-0162

BPA WORLDWIDE BUSINESS



From concept to completion, Technip Umbilicals offers full lifecycle services to compliment industry leading products

Technip
take it further.

www.technip.com

What's Trending?

Planned to perfection

- Block Island completes construction
- Israel to hold first offshore round
- Ithaca's Stella set for November

Activity

Gretchen H. Watkins, COO at Maersk Oil.
Photo from Maersk Drilling.

Maersk names new jackup

Maersk Drilling held a naming ceremony at Invergordon, Scotland, for its latest jackup, the Maersk Highlander, which is meant for the Culzean gas field in the North Sea.

Maersk Highlander
Photo from Maersk Drilling's Facebook

People

Geeta Thakorlal was named president of Intecsea in late July. Thakorlal, the firm's first female president, succeeds Neil Mackintosh, who will take on the role of executive vice president of global sales and marketing for WorleyParson's Advisian group.

HEMPEL

Tough choice

Protect your investment from the inside out, with our proven ballast tank coatings solutions.
Hempadur BT 35750 has been developed to give you proven protection.

- NORSOK M-501 approved.
- IMO MSC 215(82) approved.
- Long lasting finish.

Choose Hempadur BT 35750 as part of your corrosion protection coating system for tough, effective results.

Contact us at offshore@hempel.com today.

offshore.hempel.com

Undercurrents

Just keep floating

Welcome to our annual FPSO issue, where *OE* seeks to shed light on the latest projects and the technologies that serve them.

The downturn has been hard on all sectors of the oil and gas industry and the FPSO market has certainly seen orders canceled and projects delayed. Clarksons Research presented its findings on the FPSO market in June 2016 at the Standard Club FPSO Roundtable Seminar in Singapore, reporting that the global FPSO fleet size is 194 total units, with 172 units active and 22 units idle. The region with the largest number of idle FPSOs is Asia Pacific, where 19% of 63 units are idle.

The *Turritella* FPSO.
Photo from Shell.

Clarksons also reported that orderbooks had taken a hit since the downturn. In 2016, the firm lists just two FPSOs on the books. 2017 fares a bit better with 17 units (11 conversions and six construction). In 2018, the number is expected to dwindle to six units. By 2019, it's expected there will be just one unit on the books.

Clarksons highlights that, over the last 12 months, delivery schedules have been extended; half of the units on order have been seen delivery dates pushed back or canceled. The firm attributes Brazilian oil company Petrobras' troubles as a key issue, since one-third of the orderbook had been expected to be deployed in Brazil. But, Petrobras is not the only factor, fabrication delays are also to blame, the research firm says.

Despite this negative news, most researchers believe Brazil's offshore exploration could heat up again. Rystad Energy shares its view of the South American market, in the wake of high profile discoveries like Exxon's Guyana find and Statoil's acquisition of Carcara assets off Brazil, on page 56 of this issue.

And, while some projects have certainly hit snags over the last several months, the projects that achieved final investment decision years ago continue to plow ahead. A few FPSOs have come online this year. Last month (August), Tullow achieved first oil from its Tweneboa, Enyenra, Ntomme (TEN) field development, offshore Ghana, with MODEC's *Prof. John Evans Atta Mills* FPSO. In July, Petrobras started production from the *Cidade de Saquarema* FPSO unit on the Lula field, offshore Brazil. And there are more certain to follow.

In this issue, *OE* profiles supermajor Shell's Stones development, which boasts the deepest floating production facility in the world, the *Turritella* FPSO. The unit is only the second FPSO to call the US-side of the Gulf of Mexico home. It took a lot of planning and technical ingenuity from across Shell deepwater projects to get the Stones development where it is today. Read more about the project on page 22.

Of course, there's so much more of interest in this issue. We're delighted to break the news that Total has been the first to achieve a fully all-electric subsea well at its K5F-3 project offshore the Netherlands. We take a close look at this project and a deep dive into the all-electric subsea future, starting on page 38 of this issue.

Looking forward to our October issue Visualization feature, we're excited to offer staff reports on the rising use of drones in the offshore industry as a method for inspection. Adoption of this technology has been remarkably fast and is becoming more and more sophisticated. There's no doubt that there will be more coming from this space in future. Be sure not to miss the October issue to learn more. OE

OE

PUBLISHING & MARKETING
Chairman/Publisher
Shaun Wymes
swymes@atcomedia.com

EDITORIAL
Managing Editor
Audrey Leon
aleon@atcomedia.com
European Editor
Elaine Maslin
emaslin@atcomedia.com
Asia Pacific Editor
Audrey Raj
araj@atcomedia.com
Web Editor
Melissa Sustaita
msustaita@atcomedia.com
Editorial Assistant
Jerry Lee

ART AND PRODUCTION
Bonnie James
Verzell James

CONFERENCES & EVENTS
Events Coordinator
Jennifer Granda
jgranda@atcomedia.com
Exhibition/Sponsorship Sales
Gisset Capriles
gcapriles@atcomedia.com

PRINT
Quad Graphics, West Allis, Wisconsin, USA

SUBSCRIPTIONS
To subscribe or update details, email: subservices@atcomedia.com or visit oedigital.com. Rates $99/year for non-qualified requests. $10 for individual copy.
NOTICE: Print magazine delivery for free qualified subscriptions restricted to North America & Western Europe. All other regions will be receive digital format – email address is required.

CIRCULATION
Inquiries about back issues or delivery problems should be directed to subservices@atcomedia.com

REPRINTS
Print and electronic reprints are available for an upcoming conference or for use as a marketing tool. Reprinted on quality stock with advertisements removed, our minimum order is a quantity of 100. For more information, call Rhonda Brown at Foster Printing: 1-866-879-9144 ext.194 or email rhondab@fosterprinting.com

DIGITAL
www.oedigital.com
Facebook: fb.me/ReadOEmag
Twitter: twitter.com/OEdigital
Linked in: www.linkedin.com/groups/4412993

tyco
Gas & Flame Detection

Five industry leaders in gas and flame detection have united giving you the power to protect in more ways and in more applications than ever before. **Together we detect. Forever we protect.**

Learn more at www.TycoGFD.com

THE POWER OF MORE

SCOTT SAFETY // detcon inc. // SIMTRONICS Fire & Gas // GMI Gas Measurement Instruments // OLDHAM

Copyright © 2016 Tyco. All Rights Reserved. TYCO, TYCO GAS AND FLAME DETECTION and all product names listed in this document are marks and/or registered marks. Unauthorized use is strictly prohibited.

OPINION

The Barrel

Down and up?

"Based on the comments associated with the Q2 results of the large service companies, they all seem convinced that we are at or beyond the bottom."

I'm sure that everyone is as fed up with this downturn as I am, partly because this is the longest ever downturn our industry has experienced, but also because the path to recovery is opaque.

The depression is exacerbated by the weekly yoyo of crude prices. In the last month, prices touched US$50 resulting in a minor uptick in North American shale activity then slumped again, dashing hopes of a sustainable near-term upturn in activity.

The underlying cause of this situation is the reaction of crude traders to the weekly data coming out of the US in relation to crude and refined product stocks. This was particularly well illustrated in early August when a record draw in refined product of 3.3 MMbbl was reported. This compared to expectations of 300,000 bbl! Previous weeks had reported a surprise refined product build. Similar issues undermine the credibility of the weekly crude inventory reports.

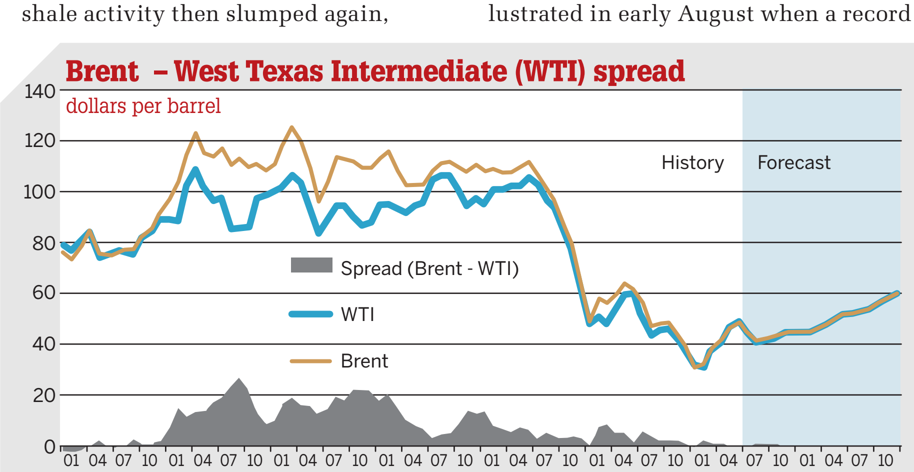
It would be much more appropriate to focus on the things that really matter in the long term: firstly, global growth, which drives demand for oil and gas; secondly, the reported production declines from exploration and production companies; and thirdly, the observations of the service companies that bear witness to what is actually happening in the oilfields. You could add the movement of the US dollar to this list.

Based on the comments associated with the Q2 results of the large service companies, they all seem convinced that we are at or beyond the bottom. To paraphrase a quote from the Halliburton call: "it's actually light at the end of the tunnel and not an oncoming train."

Meantime, the long predicted wave of corporate failures is beginning to wash over us. Some of these businesses can be saved by going through an insolvency process, but no amount of restructuring or money can help those companies that are losing money at an operating level.

This is my last monthly column for *Offshore Engineer (OE)* and I would like to leave you with a positive outlook for our industry. I am certain that, as long as we don't have another financial crisis or similar global trauma that devastates crude demand, there will be a pickup in activity over the next 18 months.

I plan to spend as much of my time as possible helping investors and companies to position for that outcome. Good luck. **OE**

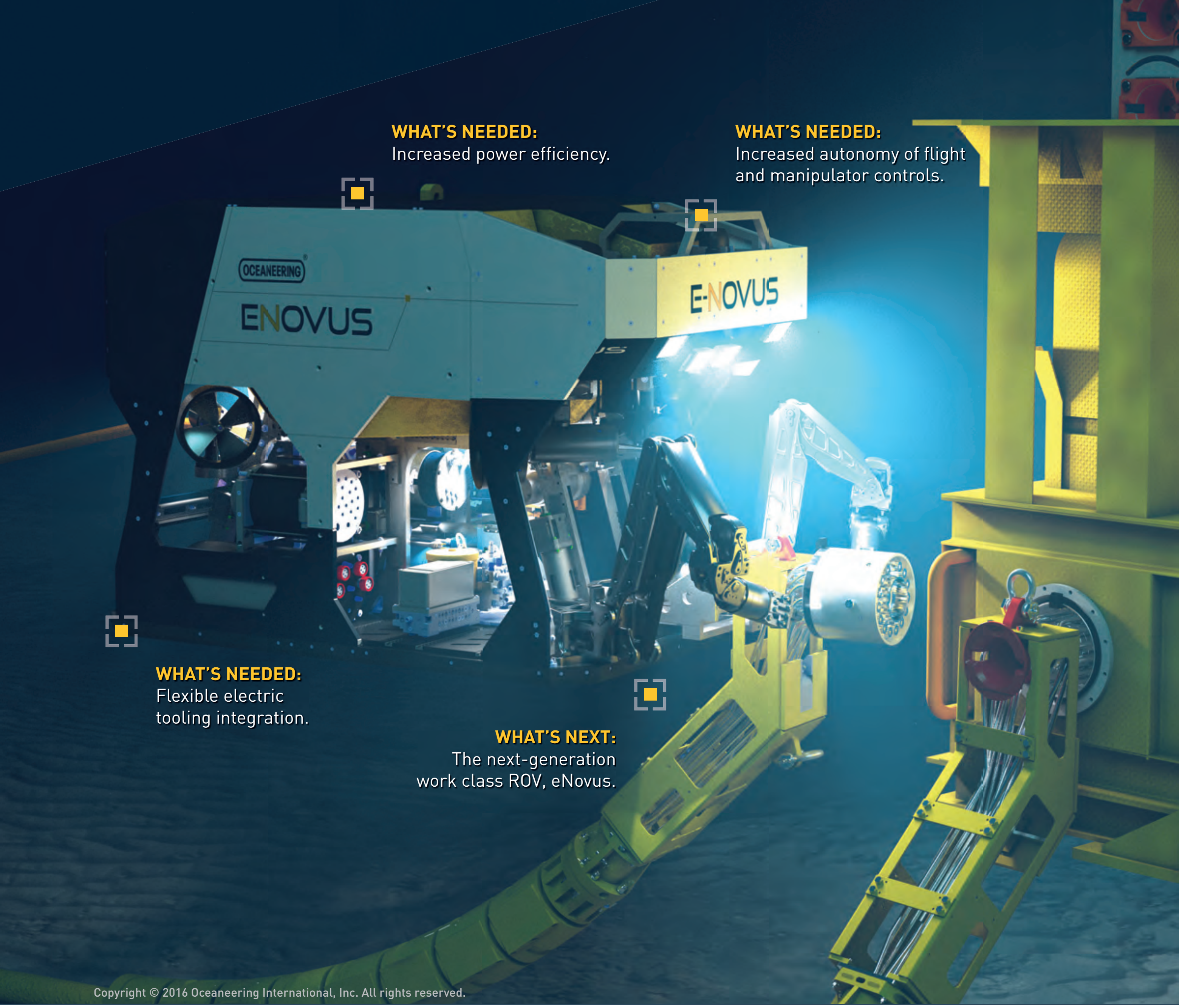


Source: U.S. Energy Information Administration, *Short-Term Energy Outlook*

***Colin Welsh** is head of international energy investment banking at Simmons & Company International, part of Piper Jaffray. He studied accountancy, economics and law at the University of Aberdeen and qualified as a Scottish Chartered Accountant with Ernst & Whinney (now EY).*

OCEANEERING®

Connecting What's Needed with What's Next™

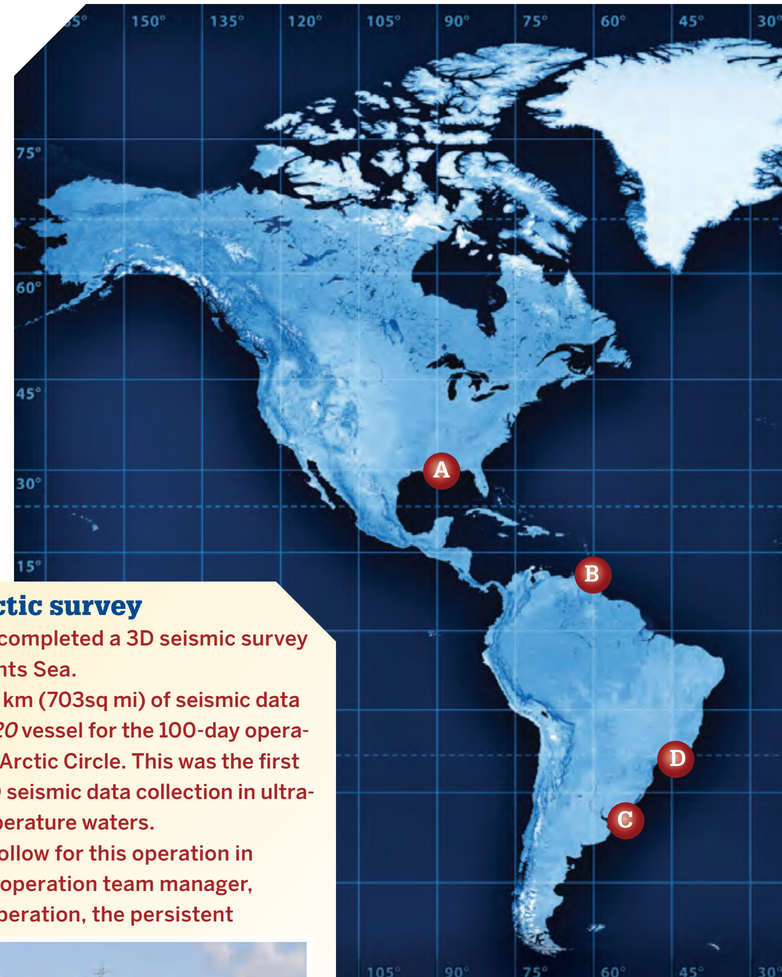


Copyright © 2016 Oceaneering International, Inc. All rights reserved.

As the trusted subsea connection specialist, we focus intently on the many challenges that global offshore operators face—from routine to extreme. To solve beyond the status quo, our newly advanced and environmentally friendly eNovus ROV provides a cleaner and more efficient approach to subsea operations. The result of this cost-effective, innovative solution is maximized power, efficiency, and configurability for our clients' needs.

Connect with what's next at **Oceaneering.com/WhatsNext**

Global E&P Briefs



A Shell hits Fort Sumter pay

Shell discovered hydrocarbons at the Fort Sumter deepwater well in the US Gulf of Mexico. Estimated recoverable resources are more than 125 MMboe, the supermajor says. The *Noble Globetrotter I* drillship drilled the Fort Sumter well in 7062ft (2152m) water depth to 28,016ft (8539m) total vertical depth. Fort Sumter is in Mississippi Canyon Block 566, approximately 73mi (117km) offshore New Orleans. An appraisal sidetrack well was later drilled to a depth of 29,200ft (8900m) measured depth.

B BHP in LeClerc find

BHP Billiton discovered gas at the deepwater LeClerc well offshore Trinidad.

The LeClerc 1 ST01 well was drilled in Block 5, in 2500-8500ft water depth, 135mi off the east coast of Trinidad using Transocean's *Deepwater Invictus* drillship. It reached 22,876ft total depth, with gas encountered in multiple zones.

The LeClerc well, spudded 21 May, is the first of three deepwater wells, and is part of the BHP's eight-well, deepwater program in the area.

BHP Billiton holds 65% interest in the block. Its partner Shell holds 35%.

C Uruguay ramps up

Total's Uruguay-subsidiary awarded Fugro a contract to support the French oil major's drilling campaign offshore Uruguay at the Raya-1 well, which is to be the deepest well, by water depth, ever drilled. Fugro is supplying two state-of-the-art 200hp FCV 4000D work-class ROV systems and subsea tooling, which are installed on board the *Maersk Venturer* drillship, and a field support vessel.

Elsewhere, Tullow and partners agreed on a one-year extension with the government on Block 15 to acquire 2500sq km of new 3D seismic that will start in late 2016. Tullow also said in their Q2 report that it will plan a 3D seismic survey on the Kanuku and Orinduik licenses in 2017, nearby offshore Guyana.

D Statoil adds Carcará stake

Statoil will acquire 66% operating interest in the BM-S-8 offshore license in the Santos Basin from Brazilian national Petrobras. The US$2.5 billion acquisition includes a part of the Carcará oil discovery.

Carcará was discovered in 2012, on the geological trend of the nearby Lula and Libra area. It contains high-quality oil of around 30° API and with associated gas in a thick reservoir.

Statoil expects to achieve a declaration of commerciality in 2018 and a final investment decision in 2020+.

Carcará straddles both BM-S-8 and open acreage to the north, which is expected to be part of a license round in 2017.

E COSL completes Arctic survey

China Oilfield Services (COSL) completed a 3D seismic survey of two blocks in the north Barents Sea.

The firm recorded 1820.58sq km (703sq mi) of seismic data using the 12-streamers *HYSY 720* vessel for the 100-day operation, 900km (559mi) above the Arctic Circle. This was the first attempt by China to perform 3D seismic data collection in ultra-high latitude and ultra-low-temperature waters.

"We have no precedence to follow for this operation in North Pole," says Chen Zhiwei, operation team manager, COSL. "The low-temperature operation, the persistent daylight and the narrow window that allowed operation to take place presented unprecedented challenges to team members and the exploration equipment."


Image from China Oilfield Services Ltd.

F NF-2 drilling begins

Statoil has started drilling on the Njord North Flank-2 (NF-2) exploration well 6407/7-9 S in production license 107C, in the Norwegian Sea, says license partner Faroe Petroleum.

The well is being drilled by the *Songa Delta* semisubmersible drilling rig, in about 323m water depth, targeting the Middle and Lower Jurassic sandstone reservoirs of the Ile and Tilje formations in a fault-bounded structural closure, with a total depth in the Lower Jurassic Åre Formation.

"If successful this will add another tie-in opportunity to the Greater Njord Area and the Njord Future Project," says Graham Stewart, chief executive of Faroe Petroleum.

G Premier makes Bagpuss discovery

Premier Oil has made a discovery on its Bagpuss heavy oil exploration well on the Halibut Horst in the Outer Moray Firth, off Scotland, in the North Sea. Wood Mackenzie says a discovery here could open a new play.

The 13/25-1 well, drilling using the *Ocean Valiant* semisubmersible drilling rig, reached 1532ft total vertical depth subsea and encountered 41ft of

hydrocarbon-bearing sands within a 68ft hydrocarbon column.

The sands had 25-33% porosity and indications were that the oil was heavy. The well is now being plugged and abandoned.

Bagpuss and the nearby Blofeld heavy oil prospects together could contain up to 2 billion bbl in place.

H Oyo-8 back online

The Erin Energy-operated Oyo-8 well has returned to production offshore Nigeria. Oyo-8 is producing more than 7000 b/d following intervention work.

An emergency shut down of the Oyo-7 well in July has resulted in the temporary loss of 1400 b/d, but plans are being made to bring the well back online by using nitrogen from the production facilities.

Operator Erin Energy is also preparing for the next drilling campaign, planned to begin in Q4. The Oyo-9 well, in the central area of the Oyo field in OML 120, will be tied into existing production facilities.

J Cairn eyes more SNE resources

Cairn Energy plans to drill for an additional 500 MMbbl offshore Senegal. The latest program will include an appraisal of the SNE discovery, as well as for further exploration drilling in the acreage. It will also help firm up ongoing conceptual development planning, in which Cairn says that it will look at a number of options, including phased development.

So far, appraisal of SNE has increased Cairn's 2C oil resources to 473 MMbbl with associated 2C oil in place in excess of 2.7 billion bbl.

K TEN first oil

Tullow Oil achieved first oil from the Tweneboa, Enyenra, Ntomme (TEN) fields offshore Ghana with MODEC's *Prof. John Evans Atta Mills* floating production and storage offloading (FPSO) vessel.

Production will gradually increase throughout the year towards the FPSO's capacity of 80,000 b/d. The average in 2016 is anticipated to be 23,000 b/d gross. The *Prof. John Evans Atta Mills* is moored some 60km offshore western Ghana at about 1500m water depth.

L Israel to hold licensing round

Israel's Ministry of Infrastructures, Energy and Water Resources (MIEWR) will offer 24 blocks in the Levant Basin in the Eastern Mediterranean Sea, in the

I Hydrates discovered offshore India

Large, highly enriched accumulations of natural gas hydrates have been discovered in the Bay of Bengal, India, according to the US Geological Survey (USGS), which assisted in the exploration program.

It is the first discovery of its kind in the Indian Ocean that has the potential to be producible, the USGS says.

Using the Japanese research vessel *Chikyu (pictured)*, gas hydrates were found in coarse-grained sand-rich depositional systems in the Krishna-Godavari Basin and is made up of a sand-rich, gas-hydrate-bearing fan and channel-levee gas hydrate prospects. The next steps for research will involve production testing in these sand reservoirs to determine whether natural gas production is practical and economic.

The discovery is part of the Indian National Gas Hydrate Program Expedition 02, involving scientists from India, Japan, and the US, and led by the Oil and Natural Gas Corp. on behalf of the Ministry of Petroleum and Natural Gas India.


Photo from JAMSTEC.

NEWS

Global E&P Briefs

country's first offshore energy licensing round to be held in November. The blocks, some of which are close to major gas discoveries, are in water depths ranging between 1500-1800m.

A recent, third-party basin modeling study concluded that as much as an estimated 6.6 billion bo and 75 Tcf of gas are yet to be found in the offshore part of the basin. MIEWR has made a data package available, which includes speculative seismic data and historical well data. The closing date for bids will be March 2017.

M Rosneft in Wild Orchid discovery

Russia's Rosneft has made a gas condensate discovery at the PLDD-1X exploration well in the Wild Orchid gas condensate field, Nam Con Son Basin, offshore Vietnam.

The *Hakuryu-5* semisubmersible drilled the well during Q2, operated by RN-Vietnam, in Block 06.1.

Later this year, the operator plans to shoot broadband 3D seismic on the block to boost production and exploration potential.

N Gazprom Neft adds production wells

Russia's Gazprom Neft increased production at the Prirazlomnoye field by adding two production and two injection wells, now reaching 6000 tonne/d. The firm says field development is set to total 32 wells.

The Prirazlomnoye oilfield is in the Pechora Sea, 60km from shore, northwest of Russia. The operator says recoverable reserves are about 70 million tonne.

O Production uptick in Gulf of Thailand

Production from the Chevron-operated B8/32 and B9A complex in the Gulf of Thailand has increased to an average gross production of 52,289 boe/d following wireline zonal recompletions and seven infill wells drilled in Q2 2016.

KrisEnergy, who partnered in the aforementioned Chevron complex, plan to boost production at its G11/48 contract area, also in the Gulf of Thailand. The firm is drilling four infill wells, which are expected to add 4000 bo/d gross to the current 9722 bo/d average gross production.

P Australia offers 2016 offshore acreage

The Australian government will offer 28 exploration areas as part of its 2016 Offshore Petroleum Exploration Acreage Release. The areas span five basins – Bonparte, Browse, Offshore Canning, Roebuck, and Northern Carnarvon – in Commonwealth waters offshore Ashmore, Cartier Islands and Western Australia.

Twenty-five areas are available for work program bidding and three areas for cash bidding. Areas in the Round One work program include AC16-1, AC16-2, W16-1, W16-3, W16-8, W16-10, W16-11, W16-13, W16-15, W16-16, W16-19, W16-20, W16-21, with a closing date of 8 December.

The cash bid prequalification round, which closes on 20 October, includes areas W16-17, W16-22, W16-25. The cash bid auction closes on 2 February 2017. Round Two closes on 23 March.

Contracts

SapuraKencana wins Pemex pipeline work

Pemex selected SapuraKencana for work on the Ku-Maloob-Zaap (KMZ) project offshore Campeche, Mexico.

The contract is for the procurement and construction of a 36in, 18km-long sour gas pipeline (KMZ – 76) from platform E-KU-A2 to platform CA-AJ-1 (J4), and is worth approximately US$113 million. The scope comprises the transportation and installation of pipelines, crossings, topside modifications and subsea works, including procurement and project management. Work is scheduled to start July 2016 until March 2017.

PIM wins Nexen contract

Plant Integrity Management (PIM) won a five-year contract with Nexen. The contract covers provision of inspection management services on Nexen's North Sea assets, including delivering integrity management services covering pressure systems, structures and pipelines.

PJV supplies Culzean valves

PJ Valves (PJV) has been awarded US$1.3 million (£1 million) worth of contracts to supply over 1000 valves to Maersk Oil's Culzean field in the UK North Sea.

PJV will manufacture forged cast gate globe and check valves in super duplex and super alloys for the wellhead, living and central processing platforms. The company will also supply wafer check valves to prevent fluid backflow on these facilities. The valve package is scheduled to be delivered in 2017.

Because of the success of the front-end scope, PJV has also been awarded contracts for the compressor, metering and water treatment packages.

Sea Trucks bags PIAM pipelay gig

Enap Sipetrol Argentina chose Sea Trucks to carry out pipelay construction for the PIAM Project in the Magallanes Field offshore Argentina.

The scope covers engineering, project management and installation of three pipelines of various sizes ranging from 6-14in, with one shore approach, as well as the installation of tie-in spools and risers. It also includes abandonment of two existing lines and recovery of flexibles. Water depths in the field are up to 70m. At the back of the installation campaign, Sea Trucks has also been awarded an accommodation services contract.

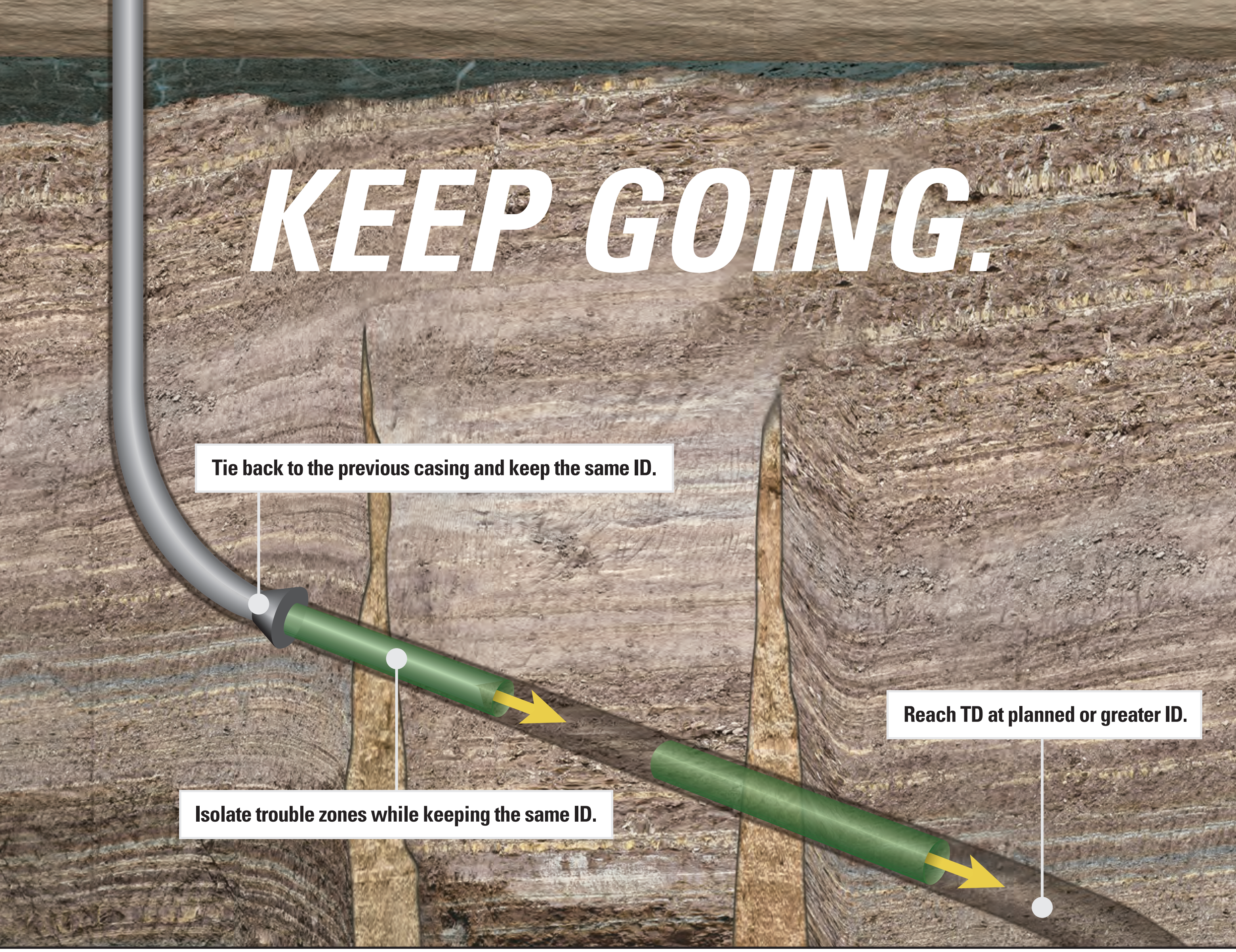
Offshore activities are scheduled to commence in Q4 2016, using the *Jascon 34*, Sea Truck's DP3 pipelay construction and accommodation vessel.

GE wins Anoa decommissioning

GE Oil & Gas subsidiary PT VetcoGray Indonesia will carry out field decommissioning for Premier Oil, to support the shutdown of four subsea wells in the Anoa field offshore Indonesia. GE will prepare the field's subsea production trees for removal, supporting the removal of flowlines and production umbilicals, installation of intervention hot stab assemblies and provision of annulus and flowline flanges.

Once the wells have been made ready for decommissioning, the tree caps, subsea trees, and tubing hangers will be removed, cement plugs set and the seabed cleared to comply with local regulations. The trees were among the first to be installed by GE in the Asia Pacific region in the 1990s. ■


... and his spirit hovered
over the waters
Allseas



SameDrift™ The More Efficient Way To Get Through Trouble Zones.

Enventure's SameDrift™ lets you extend a casing string to isolate trouble zones, **while keeping the same ID**. You can either tie back to the previous casing or simply clad the zone – or both. This ground-breaking technology will help you get through trouble zones more efficiently than ever before. The results?

- You'll reduce NPT.
- You'll start production sooner.
- You'll increase production rates.

To find out more about Enventure's ground-breaking SameDrift technology, visit us at:
www.EnventureGT.com/SameDrift

ENVENTURE®
EXPAND YOUR POSSIBILITIES

SAMEDRIFT™
An Enventure Technology

Beginning of the end

Putting the Brent field online in 1976 was a feat. Decommissioning the field's four massive platforms is equally challenging. Elaine Maslin sets out Shell's latest plans and how it came to them.

End of an era at Brent. Photo from Shell.

When Shell's 24,200-tonne Brent Delta topsides is lifted, now scheduled for 2017, it will be the heaviest lift ever conducted offshore using the world's largest vessel by displacement.

It will be an immense feat, not unlike the original feat to install the four Brent mega-structures, three of which are ca.300,000-tonne gravity base structures (GBS), some 186km northeast of Shetland, in the harsh northern North Sea back in the 1970s.

While the record lift will hit the headlines and leave many in awe, there have been a string of other feats on this project, including exploration into inner space, with the help of NASA, and creating a moon pool on a 40-year-old platform, not to mention the 400+ wellbore plug and abandonment (P&A) campaign.

There has also been intense work to assess how to deal with the three massive GBSs and the 31,500-tonne steel jacket. Shell's conclusion is that they would be best left in place, at least in part.

"If you think back to 1971, when the field was discovered, with first oil in 1976, which was really fast, they needed brilliant engineering," says Alistair Hope, Shell project director. "These are engineering marvels. Now we have to decommission them, we need that same ingenuity and great engineers to allow us to do this."

Duncan Manning

Business opportunity manager Duncan Manning, a former Lieutenant Colonel in the Royal Marines, with three tours in Afghanistan under his belt, says the Brent project is akin to the Olympic Games, on which he worked in 2014, in scale, complexity, difficult environment and the need to work closely with a large number of stakeholders.

Discovery to COP

Brent was discovered in 1971, in 140m cold rough water depth. First production was achieved just five years later, with one of the largest sets of infrastructure in the North Sea. Peak production from the four Brent platforms, of three different designs (Bravo and Delta – Condeep, Charlie – Sea Tank, and Alpha – steel jacket), was 500,000 bbl in 1982. Production at Brent Delta stopped in 2011, followed by Alpha and Bravo in 2014. Charlie is still producing and will reach its 40th anniversary this November, despite the field having initially been expected to produce for just 25 years.

The Brent decommissioning campaign started in 2006, some 10 years ago. A large focus – "the big ticket item" – has been on P&A work, with some 154 wells and around 400 wellbores in total to abandon. P&A work on Delta is complete, with work now focused on down-manning. P&A work is ongoing on Bravo, with work on Alpha also ramping up – the *Saipem 7000* recently replaced a crane on Alpha to enable P&A work. Meanwhile, on Charlie, an integrity program is being performed, with the support of Prosafe's flotel *Regalia*, ahead of P&A work there.

Heavy decisions

However, what's remarkable about this project is the immense amount of background work involved: some 300 reports have been produced, all of which have been scrutinized by an independent review group.

Much of this work has been to inform the decision on how to deal with the three GBS foundations, on Charlie, Delta and Bravo, and the 31,500-tonne (including marine growth) Alpha steel jacket. This has meant understanding the impact on the environment and other users of the sea, the impact onshore, technical feasibility, and cost, of all the various options, Manning says. Alternative uses, from offshore wind to carbon capture and storage, have also been assessed – in detail.

To remove the footings of the steel jacket would mean either boring down through the tops of the footings or excavating

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	2013	2014	2015	2016
Shallow (<500m)	74	73	56	10
Deep (500-1500m)	19	31	19	6
Ultradeep (>1500m)	34	13	13	5
Total	**127**	**117**	**88**	**21**
Start of 2016	127	114	72	-
date comparison	-	3	16	21

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	9	34.50	333.28
Deep	11	941.00	1595.00
Ultradeep	39	11,090.50	12,273.00
United States			
Shallow	10	70.60	155.00
Deep	17	645.36	818.57
Ultradeep	20	2487.00	2518.00
West Africa			
Shallow	108	3725.20	14,091.56
Deep	31	3392.50	5000.00
Ultradeep	10	1335.00	1000.00
Total	**246**	**23,687.16**	**37,451.13**
(last month)	(253)	(25,324.46)	(38,746.13)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	862	33,074.02	423,838.13
(last month)	(861)	33,080.72)	(423,955.13)
Deep	119	6,600.52	68,856.21
(last month)	(122)	(7,210.52)	(69,331.21)
Ultradeep	76	15,823.40	42,288.00
(last month)	(78)	(16,176.40)	(41,688.00)
Total	**1,057**	**55,497.94**	**534,982.34**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,452	(41,465)
Planned/ possible	23,977	(23,989)
	65,429	(65,454)
8-16in.		
Operational/ installed	82,864	(82,937)
Planned/ possible	49,316	(48,713)
	132,180	(131,650)
>16in.		
Operational/ installed	94,116	(93,986)
Planned/ possible	42,918	(44,457)
	137,034	(138,443)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	271	(271)
Construction/ Conversion	49	(48)
Planned/possible	299	(301)
	619	(620)
Fixed platforms		
Operational	9147	(9148)
Construction/ Conversion	88	(88)
Planned/possible	1361	(1351)
	10,596	(10,587)
Subsea wells		
Operational	4858	(4870)
Develop	397	(381)
Planned/possible	6411	(6355)
	11,666	(11,606)

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	14,537.52	20,490.00	30,551.10	23,906.22	14,283.72	21,491.21	17,655.35
(last month)	(14,560.00)	(20,490.00)	(30,835.44)	(23,901.48)	(14,600.70)	(21,138.96)	(17,438.35)
Deep	4477.34	976.73	4847.45	2833.28	2585.84	4317.83	4155.73
(last month)	(4477.00)	(976.73)	(4847.45)	(2833.28)	(2585.84)	(4317.83)	(4849.48)
Ultradeep	2342.81	1922.92	3145.58	2481.25	3457.52	4144.56	10,050.25
(last month)	(2343.00)	(1922.92)	(3141.08)	(2484.25)	(3674.65)	(4262.19)	(9964.21)
Total	**21,357.67**	**23,389.64**	**38,544.14**	**29,220.75**	**20,327.08**	**29,953.60**	**31,861.33**

4 Aug 2016

down through the seabed and doing a subsurface cut, followed by a lifting operation, Manning says. "On balance, it makes sense to leave them in place," he says. The footings will stand 55m above the seabed, 85.5m below sea level.

Removing the GBSs would be even harder. In the 1970s, they were floated out then tonnes of ballast was loaded into the cells, to pull them down to the seabed, followed by the installation of a skirt, to pin them in position. They weigh between 297,000-tonne (Charlie) and 341,000-tonne (Bravo), excluding water ballast. These facilities were not designed with decommissioning in mind at the time, Manning says. They're also relatively unique. Of the 470 facilities in the UK North Sea, there are only nine operational GBSs.

Exhaustive comparative assessments were carried out on ways to remove these structures. Shell even looked at the impact of exploding them to collapse them. Ultimately, the firm feels, on balance, leaving them in place is the best option, following precedents such as Total's Frigg GBS, which has navigation aids installed on its stub top. The three stubs will also be marked on navigation charts.

Subject to approval of its plans by the Department for Business, Energy and Industrial Strategy (DBEIS), formerly DECC (the Department of Energy and Climate), an application will be made to OSPAR (named after the Oslo and Paris conventions, which agreed terms for anti-dumping in the North-East Atlantic) for a derogation order to leave the steel jacket footings and GBSs in place. This will happen after Shell has officially submitted its decommissioning program, sometime before the end of this year. Under OSPAR rules, structures weighing under 10,000-tonnes have to be fully removed. Those above that weight, which were installed prior to 1999, can apply for a derogation order.

Cells

But, before Shell could decide the best solution for the three GBSs, it had to investigate what was in their 64 concrete cells (there are 16 cells each on Bravo and Delta and 32 cells on Charlie). While the firm was able to do modeling based on production data, etc., it needed to verify these models with real data, i.e. with actual samples sourced from the cells, a task which proved to be a multi-year challenge.

Each cell is cavernous, measuring 60m-tall and almost 20m-diameter (think St. Paul's Cathedral), with nearly 1m-thick concrete reinforced walls. Of the 64 cells, 42 were used for oil storage and separation. Oil remains in the cells, trapped

at the top ("attic oil"), as well as a waxy interface between the oil and ballast water, sediment (containing sand flushed in during a gas blow down in the 1990s) and ballast remain in them. But, access is limited, so new technologies had to be developed to reach the contents.

One of the first attempts to access the sediment was with tractor technology. But, onshore trials found the tractor would not be able to navigate the 90° corners of the filler lines into the cells. Shell then started a program to access the cells from the outside, which would mean boring through the 1m-thick reinforced concrete cell shells.

A number of contractors were engaged to deliver the program, and in 2014 their combined efforts resulted in the first cell sampling. Divers connected a base plate to the top of three Delta cells, some 80m below the waves but accessible from the platform crane. A lubricator tool was then attached to the base plate, through which a sampling tool could be sent.

Shell then hired Enpro, which built upon the original concept, creating a smaller, lighter, simpler and entirely ROV-operable system. To make operations for the removal of the attic oil easier, as Shell didn't just want to sample the sediment and attic oil, it also wanted to remove the latter, a big, innovative move was made; Shell cut a hole right through the center of the platform, to create a moon pool, to ease access to tops of the cells.

"To cut a moon pool from the top deck, through the cellar decks, allows us to effectively deploy the attic oil recovery tools far more effectively than doing it over the side," Manning says. Over the summer, the tool has been removing the attic oil from the Delta cells, helped by ROV operator ROVOP, with a platform-based ROV.

North Sea calling NASA

But, while the external access tooling was being developed, Shell was also working with NASA on a probe that could go down the filler lines. "We have a technology partnership with NASA and we reached out to them," Manning says. NASA came up with a tool, a 9in-diameter sphere containing miniaturized sonar equipment, which could be flushed down the 10in-diameter filler lines into the cells to map their insides. The spheres are attached to a tether and pulled out once they've completed their mapping. "It is technology they adapted from the technology they use on the space shuttle to understand the internal pipework condition," Manning says.

It took a series of attempts to get it to work, the first on Delta,

A CGI illustraton of the Brent field. Image from Shell.

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	99	68	31	68%
Jackup	396	244	152	61%
Semisub	122	85	37	69%
Tenders	31	21	10	67%
Total	648	418	230	64%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	26	4	86%
Jackup	25	5	20	20%
Semisub	14	9	5	64%
Tenders	N/A	N/A	N/A	N/A
Total	69	40	29	57%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	9	4	5	44%
Jackup	118	67	51	56%
Semisub	29	16	13	55%
Tenders	22	14	8	63%
Total	178	101	77	56%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	19	9	67%
Jackup	50	32	18	64%
Semisub	23	20	3	86%
Tenders	2	2	0	100%
Total	103	73	30	70%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	49	38	11	77%
Semisub	39	31	8	79%
Tenders	N/A	N/A	N/A	N/A
Total	89	69	20	77%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	112	84	28	75%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	117	87	30	74%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	17	13	4	76%
Jackup	20	10	10	50%
Semisub	5	3	2	60%
Tenders	7	5	2	71%
Total	49	31	18	63%

Eastern Europe

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

Source: InfieldRigs 13 Aug 2016

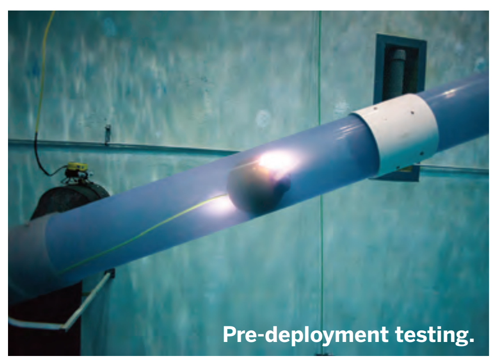
This data focuses on the marketed rig fleet and excludes assets that are under construction, retired, destroyed, deemed non-competitive or cold stacked.

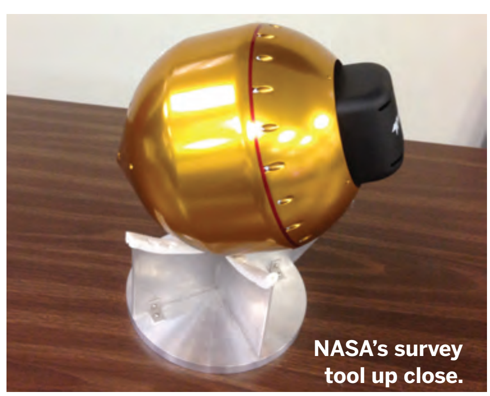
then successfully on Bravo earlier this year. The 2D sonar image was converted to a 3D model, which then allowed Shell to model the quantity of sediment.

The external sampling tools and the sphere confirmed some 4m deep of sediment. The sediment was made up of 25% sand, 25% oil and 50% water.

Now the attic oil is being successfully siphoned out. To make sure it is all removed, it is measured using a conductivity tool, to see when the attic oil stops coming through and it turns to the ballast water, as well as a UV light. While the work is being done through the platform moon pool, when the topsides are removed, it could also be done from a support vessel.


Going into inner space, with the help of NASA.
Photos from Shell.


Pre-deployment testing.


NASA's survey tool up close.

Heavy lifting

One of the next steps will be more visible – the Delta topsides removal in 2017. It's a year late, due to commissioning on the *Pioneering Spirit* lifting arms taking "longer than anyone anticipated," (*OE*: April 2016 and August 2016). Shell's Hope describes the work on each arm as being similar in complexity to commissioning a small southern North Sea platform, and then all 16 arms work together, but also act independently. However, the delay will not impact Shell's operations, Manning says. The vessel has already successfully performed a test lift. And, as *OE* went to press in late August, the vessel completed the Yme topsides removal offshore Norway.

The Delta lift will involve the *Pioneering Spirit* bow slot ballasting into position beneath the topside, before using 16, 65m-long, lifting arms to lift the platform from its base. It's an ambitious system, but one in which Shell has confidence, having done its own studies on the design prior to signing a contract for the unit in 2013.

To do the lift, however, reinforcement work had to be carried out on the topsides. Eight cruciform lifting points, weighing 120-tonnes in total, had to be added to the underside of the platform, for the mating with the *Pioneering Spirit*'s lifting arms. Structural reinforcement was also added to the lower decks.

Three shear restraints, at around 12m-diameter and weighing about 36-tonne each, have also been installed in each leg, to hold the platform in place after leg cutting, by Cut UK. They will also accommodate the shear forces during the lift, Manning says. "They effectively make the cut legs as strong as they were before the cuts," Hope says.

Based on the Delta lift plan, eight lifting points were added, two more than the six originally thought necessary. The 16 lifting arms will also be acting in pairs (two for each lifting point), Hope says, adding further redundancy. It's a conservative approach for the first lift. "We are actually looking at how we can make this less conservative in the future, as there is substantial conservatism in this," he says.

Others have also had to invest to make this project happen. Able UK, in northeast England, had to upgrade its quayside in order to receive the topsides, with some 1200 piles installed then covered in a concrete pad ready to receive Delta's topsides. Able will also lead recycling efforts, hoped to reach 97%, with a level of re-use. Able already has designs on the galley and that elements such as valves are likely to be reused, more and more so when this market grows, Hope says.

Cleaning up

It's not just about the platforms. Shell also has some 28 pipelines, including umbilicals and flexibles, to deal with, measuring from 2.5-36in in diameter, on a case-by-case basis, with either removal or flushing and burial. And even then, clean-up work will be needed around the platforms, to clear all debris, such as scaffolding, broken off during severe weather.

Life goes on

Delta will be the first topside to be removed in the campaign, in 2017, with three more to come, as well as completion of the P&A program. Lessons learned in this project will be passed on, Manning says. "Some of this is about driving greater efficiencies in delivery," he says, "conducting planning and execution and preparation early. Some of it is about ensuring the platform is prepared for end-of-life activity, that cranes are robust, there's robust power solutions and you're not reliant on reservoir gas to provide power. Some of it is ensuring there is the right focus on the platform."

There's also scope for new technology to come in and impact how decommissioning is done, not least in the P&A space, which is nearly half the total cost of decommissioning. "Being able to P&A more efficiently so you can abandon a well in one run would be the dream ticket," Manning says. "We are tracking a number of technologies in the P&A space with various levels of technology readiness and expectations." The issue here, he says, is finding test wells for these technologies. Doing it 186km offshore in the rough northern North Sea isn't perhaps ideal. More broadly, doing things quicker and more efficiently is an all-round goal, he says.

But, it's not all about decommissioning. In order that fields, which currently produce over the Brent facilities, i.e. the Penguins development, which produces through Brent Charlie, FLAGS (Far North Liquids and Associated Gas System) pipeline, are not left stranded, a bypass route is due to be installed.

The facilities will also require periodic inspection, something that could be well-suited to autonomous underwater robotics, which could swim out from onshore, Manning suggests. It's a future technology, but one which could have use here. We look forward to reporting on it, when the time comes. OE

تحت رعاية صاحب السمو الشيخ خليفة بن زايد آل نهيان رئيس دولة الإمارات العربية المتحدة

Under the patronage of H.H. Sheikh Khalifa Bin Zayed Al Nahyan, the President of the United Arab Emirates

المناطق البحرية

OFFSHORE & MARINE

Host

أدنوك ADNOC

Co-located with:
The Abu Dhabi International Petroleum Exhibition & Conference
7-10 November 2016

ADIPEC OFFSHORE AND MARINE YOUR GATEWAY TO THE MIDDLE EAST

Why exhibit at Offshore & Marine 2016?

- **Capitalise on US$25bn worth** of offshore oil and gas investments in the region
- **Network with international offshore and marine companies** from more than 40 countries
- **Showcase your products and services** to 15,000+ marine and offshore industry professionals
- **Meet new prospects** and maintain relationships with existing customers
- **Enjoy unrivalled networking and business opportunities** with our unique matchmaking programme
- **Gain cutting-edge knowledge and share best practices** at the Offshore and Marine Conference - website: www.adipec.com/conference
- **Enjoy exclusive discounted flights with Etihad and hotel stays** with our dedicated travel partners - www.adipec.com/travel

ADIPEC 2016 OFFSHORE & MARINE IN NUMBERS

4,500+ SQUARE METERS SPACE

100+ EXHIBITORS

15,000+ OFFSHORE & MARINE ATTENDEES

250+ CONFERENCE DELEGATES

30+ CONFERENCE SPEAKERS

BOOK YOUR STAND TODAY

adipec.sales@dmgeventsme.com
+971 2 4444 900

Supported By

Official Airline: ETIHAD AIRWAYS | Official Travel Agent: Al Masaood Travel & Services | Host City: Abu Dhabi | Official Publication: Pipeline | Venue: ADNEC | Conference Organiser: SPE Society of Petroleum Engineers | ADIPEC Organised By: dmg::events global energy

Breaking new frontiers

Shell's Stones development will be home to the Gulf of Mexico's second FPSO, but while it may be No. 2, the FPSO may hold a few firsts itself. Audrey Leon found out more.

Shell's Stones project is special in a lot of ways. The supermajor boasts that the floating production, storage and offloading (FPSO) unit engaged on the project, *Turritella*, will be the deepest production facility in the world at 9500ft (2900m) water depth.

The *Turritella* FPSO – owned and operated by a joint venture owned by affiliates of SBM Offshore (55%), Mitsubishi (30%) and Nippon Yusen Kabushiki Kaisha (15%) – nudged out the previous record holder, the *BW Pioneer* (the Gulf of Mexico's first FPSO), which is installed at Petrobras' Cascade/Chinook development, also close by the Stones project within Walker Ridge, in approximately 8900ft of water. But, while it is the second FPSO unit in the Gulf of Mexico, the project has enjoyed many firsts (See chart).

The field

Stones was discovered in 2005 in Walker Ridge Block 508, some 200mi off Louisiana. Back then, the operator on the project was BP (59%) along with Shell (26%) and Marathon (15%). The prospect was drilled in 9576ft of water and reached 28,560ft true vertical depth in March 2005.

Three years later, the Stones-3 well would reach 29,400ft and confirm the discovery of multiple oil-bearing sands. The field consists of nine Outer Continental Shelf blocks. Many considerations were taken into account during the concept selection phase. For Shell, Stones is interesting because the reservoir is not particularly well known, says Curtis Lohr – Stones project manager, Shell International E&P.

"We don't have a lot of production history in this part of the Gulf of Mexico – that's why it's considered a frontier," he says. "If you look at where the FPSO is located, the drill center is in 9500ft of water, but also in this area there is a plateau that's in 7500ft of water. The sea floor is very rugged, which created some challenges in terms of routing pipelines."

Other potentials challenges, native to the Gulf, would be extreme weather events such as hurricanes, and in particular,

Aerial views of the *Turritella* FPSO while docked at Keppel's yard. Photos from Shell.

Firsts

- *Turritella* is the first FPSO used by Shell in the Gulf of Mexico
- The deepest floating production unit in the world
- The largest disconnectable buoy
- The first disconnectable FPSO with steel lazy-wave risers in ultra-deepwater

how to safely shut down operations and get people out of harm's way. This was one factor that led Shell to choose a disconnectable FPSO for the project. Another factor, Lohr said, was the flexibility to disconnect and leave in the event of extreme weather, but to also not have to use an oil export pipeline.

"The advantage of using a FPSO for this frontier project is the flexibility that it gives Shell –to learn more about this reservoir and grow accordingly," Lohr says. "Stones is a really exciting prospect for Shell. It could turn out that it is an extremely large find, but we won't know until we start producing."

According to SBM Offshore's *Turritella* factsheet, released this May, the disconnectable capability allows the FPSO to not only quickly and safely sail away in the event of a hurricane, but also quickly resume production once the hurricane has passed the location, which Shell highlighted as an important factor for productivity at the field.

Additionally, SBM Offshore said another highlight of the *Turritella* FPSO is its ability to readjust each mooring line's tension without the need to install any device on the FPSO. "It pioneers the use of an in-line mooring connector (ILMC), which gives direct access to the mooring line for re-tension purposes. This feature allows more flexibility when the need arises to adjust the tension of mooring lines, even during the early phase of the system installation," according to the company's factsheet.

The development

Shell reached final investment decision on the project in May 2013. Stones will be a phased development, with the first phase comprising two subsea production wells tied back to the *Turritella* FPSO. In all, there will be eight wells connected back to the FPSO. Shell expects to add six wells, in later phases after first oil, with multiphase pumping. The eight wells will be connected to the FPSO through two drill centers. The reservoir depth is around 26,500ft (8077m) below sea level and 17,000ft (5181m) below the mudline.

In October 2015, Technip was awarded the contract for the development of subsea infrastructure for Stones that includes two subsea production tiebacks to the FPSO, in addition to engineering of the second pipeline end terminations (PLETs); fabrication of the PLETs and piles; and installation of the subsea production system, inclusive of associated project management, engineering and stalk fabrication.

In August last year, OneSubsea landed a contract to supply subsea processing systems, which includes a dual pump station with two 3MW single-phase pumps and two subsea control modules, a topside power and control module, a barrier-fluid hydraulic power unit with associated spares as well as installation and maintenance tools.

Shell indicated multiphase seafloor pumping is planned for a later phase to pump oil and gas from the seabed to the FPSO, potentially increasing recoverable volumes and production rates. Shell estimates peak production could achieve approximately 50,000 boe/d.

The FPSO

While Stones is the first project in the Gulf of Mexico to utilize a FPSO for Shell, it is not their first FPSO project overall. Shell has 11 other FPSOs globally including the *Bonga* FPSO, 120km offshore Nigeria, in the Gulf of Guinea. *Bonga* came

An aerial view of Stones topsides at the quay in Singapore.
Photo from Shell.

online in 2005 at 3281ft (1000m) water depth. It's one of the largest FPSOs in the world, measuring 300m long and 12 stories high; the deck is the size of three football fields. The FPSO, when full with oil, weighs 300,000-tonne.

Lohr has worked with Shell for over 30 years on some of the company's biggest deepwater frontier projects, such as Auger, Bonga, Perdido, and now Stones. Lohr joined the Stones project in 2010.

"The exciting thing about all the Shell projects I've been involved with and what they have in common is that they are all deepwater frontier projects," Lohr says. "And in many cases these projects opened up new frontiers in different regions.

"Auger, for example, opened up deepwater worldwide – that one is also in the Gulf of Mexico. Bonga did a similar thing for Nigeria, and Perdido is the deepest drilling and production system in the world. And now Stones will be the deepest production system anywhere (in 9500ft of water)."

Lohr says that with Stones, Shell opted to have contractor SBM Offshore design the facility, with the Shell providing the functional specifications.

"For Shell, most of our experience in the deepwater Gulf of Mexico has been with TLP hosts. Perdido being an exception," Lohr says. "There was a learning curve, but (in terms of working with the US Bureau of Safety and Environmental Enforcement) they had the advantage of working with Petrobras (on Cascade/Chinook)."

In July 2013, Netherlands-based floating production contractor SBM Offshore was chosen to supply and lease the Stones FPSO, *Turritella*, which is a converted 159,000-dwt Suezmax tanker. The *Turritella* will be capable of producing 60,000 b/d of oil and 15 MMcf/d of gas. The hull will be able to store 800,000 bbl of oil.

At the time the contract was signed with Shell, SBM Offshore said the *Turritella* will be moored using buoyant turret mooring (BTM) technology, allowing the vessel to weathervane on location or to disconnect in the event of a hurricane. Steel lazy-wave risers (SLWRs) connecting the subsea facilities to the BTM will be used for the first time with a disconnectable FPSO, the company said at the time. Shell indicated the SLWRs have an arch bend, which absorbs the motion of the FPSO and boosts riser performance at extreme depths.

Lohr says that Shell has used both disconnectable FPSOs and SLWRs before, and for the first time brought these technologies together for the Stones project.

"For the SLWRs, we actually install buoyancy on the risers, so there's a S-shape to them that helps to take some of the load off the buoy and the FPSO. We have used it before on other projects and we felt comfortable with this technology," he says.

The *Turritella* underwent conversion work at Keppel Shipyard in Singapore with teams from SBM Offshore and Shell present.

"When we did the conversion in Singapore, one of the things we communicated to the contractor – Keppel – is even though this is not the largest FPSO in the world, even though it is not the most complicated FPSO in the world – it is still special because it is the deepest," Lohr says. "We did that because we wanted them to understand that we wanted them to build something special with no harm. We have been very focused on safety – we have an outstanding safety record on the project." And Lohr says there were over 13 million man hours spent on the construction of the FPSO in Singapore without incident. The *Turritella* set sail from Singapore to the Gulf of Mexico in November 2015 and arrived at its location in late December last year. "We're working hard on (first production), and it should be sometime in the coming months," he says.

In June this year, InterMoor announced it had completed the final tensioning and chain cutting operations on *Turritella*. InterMoor's work scope consisted of chain final tension adjustments through the ILMC system, subsequent cut and removal of excess chain, and riser pull-in rope stretching and transfer to the FPSO.

Bruno Amann, project manager, InterMoor, said that work began around Christmas and wrapped in February this year. Amann says that the project was very particular and took about three months. He notes that normally it takes longer.

Amann discussed the work scope and cited weather as a challenge. "It was winter time, and we didn't have optimal weather conditions," he says. InterMoor used the *Seacor Keith Cowan* anchor-handling vessel (AHV) to perform first phase operations, and later used a larger construction vessel on charter and on standby. Amann says that the AHV was used primarily to keep costs down.

Meeting challenges

In addition to rugged terrain and weather conditions, there are other challenges to meet when working in deepwater frontier areas.

Lohr highlights designing umbilicals that could meet the challenges associated with the extreme water depth.

"It's easy to say 9500ft of water, but more challenging to execute," Lohr says. "Because of the water depth, the tension and the load on the umbilicals becomes quite high, and we actually had to work with the contractors to come up with something that works in this water depth."

Additionally, Lohr highlights the disconnectable technology used on the project. "The way we worked with our contractors to meet the challenges of 9500ft of water is a very special thing."

The 3D advantage

For Stones, Shell took advantage of 3D printing technology to ensure the disconnectable buoy on the project came together flawlessly during the construction process. The disconnectable buoy features a design that uses syntactic foam, unlike typical disconnectable buoys that are hollow steel. The buoy features 222 pieces of foam that need to fit together in sequence. Lohr says that the use of 3D printing technology to create a model allowed Shell to ensure that there weren't any safety issues or schedule delays.

Shell produced a video earlier this year discussing how 3D printing came together to ensure the buoy construction went according to plan.

"A fundamental part of the design process is to visualize what the end product will be," says Robert Patterson, executive vice president, engineering, Shell, in the video. "3D printing allows for very rapid prototyping; allows you to engage with a design, installation sequence, safety risks of putting it together. If you do all of those things early, it leads to far better outcomes."

Amir Salem, construction engineering, Stones project, SBM Offshore, added: "Having a model like this bridges the gap between design and fabrication." **OE**

WATCH

See how Shell used 3D printing to further the Stones project. http://bit.ly/2bjkjCR

Curtis J. Lohr will discuss the Stones project at this year's Global FPSO Forum, presented by OE, on 31 August 2016. For more information, please visit: GlobalFPSO.com.

Keeping afloat

The market for floating production systems may have stalled, but FPSs will still be a key part of the offshore technology tool kit, outlines Douglas-Westwood's Ben Wilby.

The oil price collapse has deeply impacted the floating production systems (FPS) market with orders declining dramatically as operators focused on cutting budgets and redesigning projects.

With high costs and long construction periods, the FPS market was one of the worst affected sectors across the oil and gas industry. There were four orders in 2015 – down from 12 in 2013 and 17 in 2014. The order value of vessels ordered in 2015 was also low, with average cost at US$750 million, down from close to $1 billion in 2013.

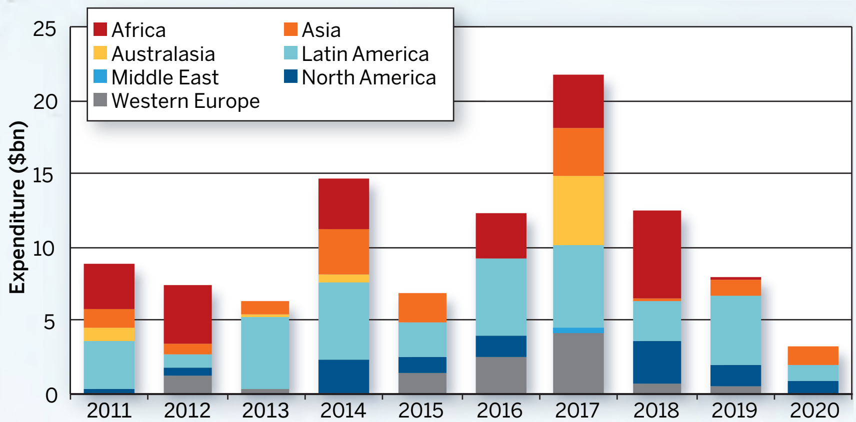
Despite this negativity, Douglas-Westwood remains confident that the FPS sector will continue to play a large role in developing the oil and gas sector, remaining a crucial component of deepwater and marginal field development.

The lack of new orders will not affect capex (capital expenditure) until 2018, as a large number of FPS units are due to be installed in 2016 and 2017. However, following this influx, a lean period for the FPS industry is expected, due to the current lack of orders. This will begin in 2018, but will grow worse from 2019-2020, with the two years accounting for just 18% of total forecast spend. By contrast, 2017 alone is expected to account for almost 40%.

The outlook

To 2020, Douglas-Westwood expects capex of $58 billion on FPS units – an increase of 31% over the preceding five-year period. A total of 63 floating production units are forecast to be installed, a decrease from 70 in the hindcast. This

Global FPS installation capex by region 2011-2020



Source: Douglas-Westwood, Q2 World Floating Production Market Forecast 2016-2020.

demonstrates the escalation of costs in the FPS sector from 2012-2014 with a number of units such as the *Ichthys* floating production, storage and offloading (FPSO) vessel and floating production semisubmersibles (FPSS) and the *Egina* FPSO costing multi-billion dollars each.

FPSOs represent by far the largest segment of the market in terms of numbers (49 installations) and capex (80%). With units such as *Ichthys* and *Appomattox*, FPSS units will account for the second largest segment of capex (9%) with tension leg platforms third (8%). The smallest segment, spars, have a forecast capex of $1.2 billion, with only two installations over the forecast.

Late in Latin America

Latin America accounts for 35% of both installations and capex, with all but one of these units being FPSOs. Brazil will dominate the region and will see 20 of the 22 expected installations in the region. The majority of these FPS units were ordered before 2014, with delays heavily impacting activity in the country. This has affected all of the FPSOs that are part of the "replicant hull" project – initially designed to reduce costs and time.

Eight converted FPSOs were ordered with identical hulls, however a number of issues including: inexperienced shipyards and late payments have meant that none are planned to be installed until 2017 – with some not expected until the 2020s. Petrobras has not ordered a unit in approximately two years. However, the contract for the *Libra* FPSO is expected to be awarded in Q3 this year.

The FPSO *Cidade de Saquarema* departs from the BRASA shipyard bound for the Lula Central field in the Santos Basin, off the coast of Rio de Janeiro, Brazil. Photo from SBM Offshore.

Deepwater dominates Africa

Africa will be the second largest region, with forecast capex of $13 billion (22%). The vast majority of this spend will be in the first few years of the forecast, with capex in 2019–2020 limited to $200 million. The majority of FPS units in the region are large and in deepwater areas – typically resulting in high costs and long lead times. This is the driver of high capex in the early years of the forecast with units such as *Kaombo* (ordered in 2014) and *Egina* (ordered in 2013) due to be installed before 2019. Prior to the oil price collapse, East Africa was expected to develop into a major hub, however, expected units have been stalled or canceled due to low oil prices.

Asian interest wanes

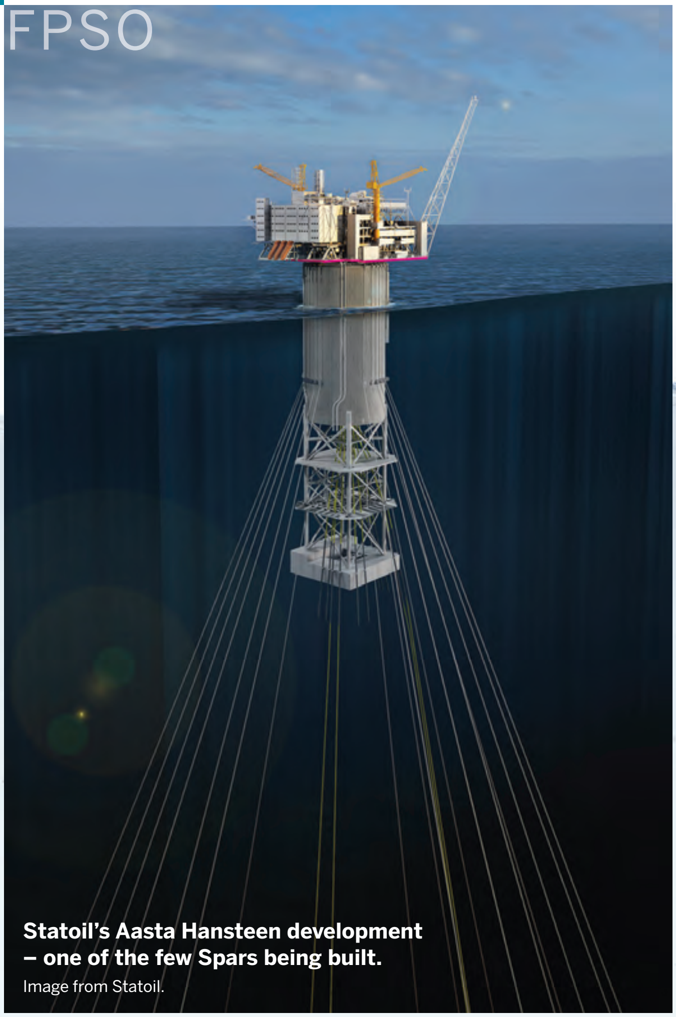
In Douglas-Westwood's 2015 forecast, Asia was the third largest market and was expected to see a substantial number of installations – second only to Latin America. The region is now expected to see capex of $5 billion from nine units – 10 less than the hindcast with a 40% reduction in capex. This is due to delays to large projects such as the IDD (Indonesia Deepwater Development) project in Indonesia and the cancellation of a number of smaller FPSO units.

European resurgence

By contrast, a resurgence of activity is expected in Western Europe. In the hindcast, the region saw capex of $3 billion from six installations. To 2020, the number of installations will double with spend increasing 180%. The increase in cost per vessel is due to a number of large, complex FPSOs for fields in the UK such as the Greater Catcher project and Dana Petroleum's Western Isles Development. The Western Isles Development was initially expected onstream in 2015, but was delayed until 2017 – with the shipyard falling behind schedule due to the challenging design of the Sevan vessel.

FLNG flounders

Over the forecast period, a stormy ride is expected for the LNG industry, as the fall in natural gas prices limits investment



Statoil's Aasta Hansteen development – one of the few Spars being built.
Image from Statoil.

in capital intensive liquefaction projects. Furthermore, the success of the pioneering projects will serve as a yardstick for stakeholder's confidence. Douglas-Westwood expects a pause in investment and the sanctioning of FLNG projects due to the market downturn.

Douglas-Westwood forecasts the capex on floating liquefaction projects will be $16.7 billion in 2016-2022, as the technology begins to emerge as a viable solution for gas developments, with the first unit of its kind expected to commence commercial production in late 2016. This landmark FLNG liquefaction project is Petronas' PFLNG *Satu,* which will be producing from the Kanowit gas field offshore Malaysia.

The long-awaited Shell *Prelude* FLNG unit, which was sanctioned in 2011, continues to experience further delays as a result of the complexity of the processing module. This unit is now expected to be in operation by 2018 – barring any further delays.

Other liquefaction vessels currently under construction and due to start-up before the end of 2018 include Perenco's *GoFLNG,* and Exmar's *FLNG.* However, Exmar is currently in talks with several parties regarding the final deployment of their unit. This is due to the termination of an initial agreement with Pacific Exploration & Production (PEP) to deploy the unit offshore Colombia. Other projects currently under construction but experiencing considerable delays include Ophir Energy's Fortuna FLNG *(OE*: June 2016) and Petronas' *Rotan* FLNG *(PFLNG 2).*

Many current FLNG projects have opted for newbuilds, however, the two proposed units in Africa, have opted for converted LNG carriers for fields offshore Cameroon and Equatorial Guinea. Africa will account for 49% of floating liquefaction expenditure over the forecast period. Yet, most of the East African projects – which account for majority of expenditure – are at an early stage.

Eni is expected to make its final investment decision on its $5 billion Coral South liquefaction vessel offshore Mozambique in 2017. The sustained industry downturn has resulted in substantial delays to capital intensive projects. This has particularly impacted developments in Australia, with delays to Browse, Scarborough and the Cash-Maple as project developers look to maximize profits for stakeholders.

Conclusions

The oil price collapse will have a significant impact over the forecast period for both the FPS and liquefaction markets, leading to substantially reduced expenditure than previously forecasted. Orders in 2015 were severely affected by the downturn and 2016 has continued this trend – though Douglas-Westwood does expect improvement in 2H 2016.

This improvement will lead to a growth in orders from projects that have been re-engineered or seen extensive cost cutting. One example is BP's Mad Dog Phase 2 in the Gulf of Mexico, initially considered uncommercial at $110/bbl oil, but is expected to be sanctioned by the end of the year – demonstrating the extent to which costs have been reduced in the wake of the oil price collapse. If cost control continues, the FPS market may emerge as a leaner, refined sector. However, this will require operators and manufacturers to remember lessons currently being learned when oil prices recover.

Marginal, deepwater and remote fields will continue to be areas of focus for the exploration and production industry. Furthermore, FPS units are likely to remain the only option for deepwater oil developments for the foreseeable future and an attractive proposition for marginal and remote fields. Given the increasing reliance upon reserves in these areas, we have confidence in the long-term proposition of the FPS sector, despite the current risks and disruption that are evident.

This year will be a landmark year for the floating liquefaction industry, as the PFLNG-*Satu* enters commercial production. This will be the first in an early wave of FLNG projects before there is a pause in investment due to the currently depressed LNG price.

Despite this, in the decades ahead, natural gas will continue to play an increasingly important role in meeting the world's energy demand. Aside from escalating gas demand, other key factors driving FLNG demand include technological advancement, monetization of stranded gas reserves, rising costs for the development of onshore terminals, shorter lead times, relocation flexibility and lower space requirements. Over the long-term, massive gas reserves discovered in remote regions such as the East African basin will continue to make the case for FLNG as development solutions. OE

Ben Wilby *is an analyst at Douglas-Westwood and the author of the North Sea Decommissioning Market Forecast. In addition, he has authored Douglas-Westwood's' Subsea Hardware, FLNG and FPS reports. He holds a BA in history from the University of Chichester.*

SULZER

As the world leader in pumping solutions for the oil and gas industry we deliver above expectations every day to customers.

Our world leading technology is reaching new frontiers with new solutions for subsea exploration, enabling safer and more efficient oil production.

We have an extensive portfolio of products for upstream applications, including pumps for injection, off-loading, fire fighting, seawater intake and general process duties.

With our extensive customer support services network we are close to the customer to provide reliable and around-the-clock solutions.

www.sulzer.com

Back to the drawing board

SBM Offshore's Fast4Ward project aims to cut costs for FPSOs by standardizing as much as possible. The Dutch firm sets out the details.

The downturn in oil prices is affecting all industries including the floating production market. Over two years ago, Amsterdam, Netherlands-based SBM Offshore reached out to clients to better understand their concerns, such as unpredictability, schedule delays, cost overruns, safety, local content restraints. SBM Offshore aims to answer these issues with the Fast4Ward project, which it presented at this year's Offshore Technology Conference. Fast4Ward aims to fast track and standardize FPSOs, to lower costs and achieve first oil faster. The new, fast-track execution model shaves 6-12 months off the average delivery schedule, according to SBM Offshore.

The starting line

"As a technology development project, the engineers working on Fast4Ward were given the freedom to re-examine the FPSO concept, and draw on the extensive experience of their colleagues across the SBM Offshore group," says Mike Wyllie, SBM Offshore's group technology director. "From initial concept to detailed design, the development followed SBM's stage gate process, ensuring the innovative ideas in Fast4Ward have reached the required level of maturity for inclusion in projects. We are confident that Fast4Ward is now set to be an industry game changer."

The company first benchmarked past, present and planned FPSOs across the industry, to create a design basis that would cover a wide market envelope, yet with flexibility to meet specific project needs. The next step was to design the Fast4Ward FPSO according to the SBM Group Technical Standards and operations codes of practice.

"I make the analogy of a recipe – you know what you want to come out of the oven, but it's a question of how you first prepare the ingredients, where you source them and how you mix them," says Jean-Michel Felderhoff, Fast4Ward project director. "Your experience and high-tech oven means the cooking time and cost of your cake are already reduced, but it depends on what extras you want to add in that will dictate if you get the full benefit from Fast4Ward. One of the key success factors of the program is the extra fat in the hull, which allows flexibility when needed by the client."

Felderhoff adds that Fast4Ward factors in for markets

An SBM proprietary technology, the Fast4Ward hull is a multipurpose floater and has the versatility to receive various large topsides with spread or turret mooring configurations. It comes fully outfitted with all the necessary marine, utility and cargo systems and with an accommodation block and bridge.

Modules under construction at the BRASA shipyard in Niterói, Brazil.
Images from SBM Offshore.

where local content and the need to manage costs and capacity in-country are part of the equation. Standardization of the hull can offer local development, since topsides integration activities can be performed in any location offering quayside access.

Inherent safety in design has always been a feature of the company's technological developments. This is principally achieved by locating hydrocarbon processing modules away from the living quarters, control rooms and equipment rooms. This design premise drives the overall FPSO layout. The Fast4Ward program leverages this safety feature of SBM's FPSOs and expands on it.

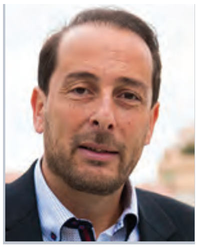
Standardization is key

While acknowledging that a fully standardized FPSO is not possible due to the different needs of every field development, there are many opportunities to create a FPSO with standardized layouts, components, and equipment whilst accommodating bespoke features.

The key to an optimal layout is modularization, and through standardization SBM Offshore can accelerate not only the design process, but also the supply chain and construction phases. To maximize the time and cost-saving opportunities, the company is able to capitalize on standardization due to many years of design, construction and operation of FPSOs. Standardization does not mean simple. The engineers came up with the solutions by tapping into the unique knowledge of the company.

The Fast4Ward FPSO employs a new build hull with a 30-year design life and is suitable for internal turret, external turret or spread moored configurations – effectively covering all potential choices that an operator may want. The hull is a multipurpose floater allowing for improved architecture; all opportunities for standardization stem from this base plate.

Basic design approval for the generic hull has been obtained from both the American Bureau of Shipping (ABS) and Bureau Veritas (BV). Water depth suitability – between 300m and 3000m is also extensive – avoiding the need for any change to the hull. The result is a generic design that can be installed in most geographic areas but that is optimized for deployment in a wide area from South America to West Africa.



Felderhoff

The company can offer the Fast4Ward FPSO either on a lease and operate basis or on a turnkey EPCI basis. However, the big enticement is likely to be the lease and operate business model, which removes the capex burden from the operators. SBM Offshore says that clients can pick and choose the necessary topsides from a catalog for inclusion on the hull, without need for structural modifications; this is a key element to the fast-track nature of the Fast4Ward project.

Behind each module is a detailed ID card featuring its main characteristics, which represents years of expertise and lessons learned from SBM Offshore's previous FPSO projects.

The module design is derived from modules already in use on SBM's operating FPSOs, and gives flexibility to be scaled up or down to suit the production requirements. Fast4Ward can embrace new topsides technologies, although it is not reliant on them. Using a standard modular concept, SBM's approach is to split the topsides into two main module categories:

- **generic modules**, highly standardized and,
- **bespoke modules**, which can be conceptually standardized, then tailored for the crude oil characteristics.

All modules are standardized in structural design and footprint, with bespoke modules standardized conceptually in terms of equipment and piping layout, thus avoiding "reinventing the wheel" on each project. This approach offers maximum module interchangeability, but without disrupting the overall functionality. The Fast4Ward hull has been designed to accommodate a topside weight of up to 35,000-ton, depending on the project crude oil processing and storage requirements. Could Fast4Ward be the solution to equip players for today's tough conditions and reboot the FPSO market at lower oil prices? OE

Passing the test

Pioneering Spirit, **loaded with Yme.**
Photos from Allseas.

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

Dutch heavy weight Allseas has marked its biggest milestone yet. As *OE* went to press, the firm announced that its mega-vessel, the US$2.7 billion *Pioneering Spirit,* had successfully completed its first commercial job, lifting Repsol Norge's 13,500-tonne Yme mobile offshore production unit, 100km offshore Norway, on 22 August. The Yme facility was then due to be taken to the newly developed dismantling yard in Lutelandet, Norway.

Pioneering Spirit is 382m-long and 124m-wide and was built to lift up to 48,000-tonne topsides and up to 25,000-tonne jackets, as well as perform pipelay work. The vessel, a concept few thought could be realized since its creation in 1987, was built in South Korea. Installation of its lifting beams was carried out at its berth at the Maasvlakte, near the mouth of Rotterdam harbor.

Pioneering Spirit was due to start its working life in summer 2015, but commissioning the lifting arms has taken longer than expected, due to their complexity (see page 20 for more).

A test program was carried out in Alexia harbor, Rotterdam, at the end of July. All 12 installed topsides lifting beams were tested to their respective lift capacities of nearly 3700-tonne. The last of the four tests, involving four beams lifting 14,700-tonne, was performed on 23 July. During harbor lifting trials, the 12 beams together lifted over 44,000-tonne.

Following the lifting trials, the vessel performed a test lift, using a 5500-tonne test platform topsides on a substructure in the K-13 field offshore Netherlands on 7 August.

Once it delivers the Yme platform to Lutelandet, *Pioneering Spirit* will return to Rotterdam where the remaining four topsides lifting beams will be installed ahead of the Shell Brent Delta topsides removal, scheduled for summer 2017.

Allseas is also contracted to lift the other three Brent topsides, at dates yet to be decided, as well as installing Statoil's Johan Sverdrup topsides, offshore Norway. **OE**

FURTHER **READING**

Take a virtual photo tour of the Pioneering Spirit: http://bit.ly/2aZbGgv

Watch videos of the 7 August sailaway: http://bit.ly/2blFs3R

OE Expert Access Webinar with NOV

Using Wired Drill Pipe to deliver project value

Despite the current low price environment, the interest and adoption of Wired Drill Pipe technology continues to grow as a way to reduce well construction costs through elimination of rig time associated with data transmission and ROP limiters.

Join OE and IntelliServ for a discussion on Wired Drill Pipe technology and how it can enable faster well delivery, potentially saving time on any directional well.

Register today at OEdigital.com

Thursday, September 15, 2016 **11 a.m. CST**

Meet the experts

Leon Hennessy
Business Development Manager - Asia Pacific & Middle East

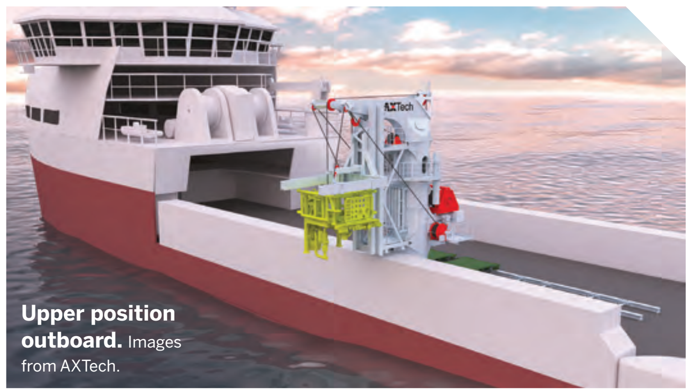
Brian Van Burkleo
Director of Business Development

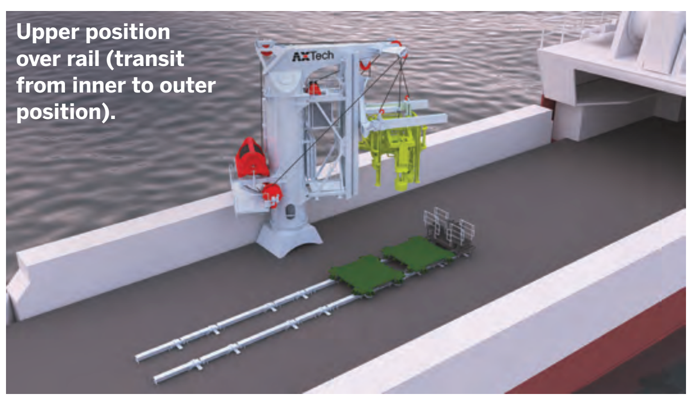
Sponsored by IntelliServ™ NOV

EPIC

Swimming against the tide

Some companies are looking to reverse the trend of heavier duty vessels with complex deck equipment. Elaine Maslin looks into some lighter concepts.


Upper position outboard. Images from AXTech.


Upper position over rail (transit from inner to outer position).


AXTech's light module handling system, Middle position in moonpool. Images from AXTech.

Lifting capacity on IMR (inspection, maintenance and repair) vessels has been growing, from 35-tonne to 70-tonne and even 420-tonne.

Operational capabilities have also increased; with sea states in which they can work increasing from 2.5m-high waves to 5.5m-high waves. Vessels have become more and more specialized – and substantially larger.

Specialized equipment has had to be built for recent projects such as the Åsgard and Gullfaks subsea compression projects offshore Norway. Molde, Norway-based AXTech was involved in designing a special lifting and handling system for these two projects, due to their scale being outside existing capabilities.

But, as systems have increased in size and complexity, costs have also increased, says Asmund Saetre, sales manager, AXTech. Plus, while a few large projects need specialized equipment, the vast majority of modules in the North Sea are smaller and don't need such large equipment. "There are more than 3000 modules (from small – choke modules, multifunction intervention modules, control modules, etc. – to larger modules – Xmas trees, power modules, compressor modules, etc.) in the [Norwegian sector] North Sea weighing 1-tonne to 380-tonne. The vast majority of them are less than 20-tonne with only a few above 60-tonne," he says.

A sharp focus on cost in the current climate also means firms are looking to use smaller vessels, with fewer crew, rented equipment and shorter mobilization times. Such vessels could potentially be taken from the currently inactive fleet, if you can use vessel independent handling equipment, Saetre suggests.

That's just what AXTech is proposing. The firm has developed a vessel independent, light module handling concept, for quick mobilization, to be used over the side or through the moon pool. The first unit, for modules up to 25-tonne, is due to be ready for use in September. It comprises a stand-alone tower, including integrated hydraulic power unit, using electrical and hydraulic power and N2 energy storage, to reduce power consumption, with a single interface on the deck of the vessel. The system, weighing about 105-tonne, could be used on a variety of vessels, such as platform supply and anchor handling tug supply vessels, and other more traditional vessels with and without cargo rails (maximum size 3m-high by 1.5m-wide).

By using a slewing structure, the system can land and pick up modules from multiple slots on the deck and does not require use of deck transport systems. Different shaped modules can be handled by adjustable prongs and are handled through the splash zone by an extended cursor guide frame, from where it is lowered using guidewires.

Safe subsea landing and liftoff are ensured by active heave compensation and automatic rope tension (ART) winches for the modules and guidewires. An active marine, roll and pitch control stabilization system, from MRPC, also based in Molde, can also be added. Saetre says the unit can by be mobilized on a vessel within 48 hours and can be transported by barge, truck or container. OE

Liftmore

A corner of Norway has something of a heritage when it comes to cranes and lifting equipment. The area has developed its own cluster, which held its first conference this year.

The Molde area has a heritage in cranes lifting equipment, dating back to more than 130 years ago when motor production started on the islands outside Molde, including thrusters, with limited means and technology at that time.

The industry has developed and in 2014, companies in the Molde area, south of Kristiansund, Norway, joined forces to form a network: Liftmore. The network builds on the crane industry tradition in the Molde area. The original members are AXTech, Axess, Prezioso Linjebygg, Motus Technology and Inventas in Molde, Triplex in Averøy and Aukra Maritime in Aukra.

The group held its first conference earlier this year with about 130 attendees and speakers from Statoil, Bosch Rexroth and others. Topics covered including use of technology from the automotive industry, simplification, standardization and industrialization in the industry, and Statoil's future vision for subsea lifting.

Gro Karine Steen Østebø, leading advisor subsea marine operations, Statoil, set out the Norwegian major's vision for what simplification, standardization and industrialization will mean for subsea lifting operations. Statoil is looking for cost saving by reduced mobilization time and operational time. Faster mobilizations can be achieved by moving from sea fastening by welding to quick connect systems. She also explains the importance of efficient operational time, through good cooperation between the bridge, ROV crane and shift supervisor. Critical stages in the lift could be improved through good deck handling and by minimizing swinging loads. Snaploads should also be minimized through the splash zone, she says.

Special handling systems could be used, increasing the ability to perform installation in harsher weather, as such a system reduces swinging loads, but, they tend to be one-offs, such as the North Sea Giant. This special handling system also has a short reach which requires multiple mobilizations.

Real-time analysis based on actual weather forecasts should also be used to reduce unnecessary time spent waiting on weather.

Using optimal lifting equipment and standardizing lifting methods could help increase efficiency and HSE (health, safety and environment) performance, she says.

But, she also predicts ultra-deepwater lifts will be less of a priority in the near-term, with lifting requirements focusing more on older fields, which require increased oil recovery methods, involving subsea processing technologies, as well as Statoil's Cap-X template technology for shallow fields.

Michael Westergren, sales manager, Prodtex, which develops automotive design tools, tooling and packages for robotics and process engineering, spoke about how Kleven shipyard is taking home production of large steel structures to Norway by using lean production methods and robots. Kleven has over the last years move a significant part of their hull production back home from "low cost" countries by using highly automated production methods.

Christine Spiten, engineer, Blueye Robotics, spoke about how Blueye started the company and their ambition to make an affordable underwater drone that can be used both by families and professionals.

The conference organizers, coming from members of the Liftmore network, are planning to hold another event next year, focusing on engineering and technology in the Molde area. OE

Rapid mobilization

Speed is of the essence on some projects and that's just what SAL Offshore faced offshore Alaska. Elaine Maslin reports.

MV *Svenja* installing the monopod.
Photos from SAL Offshore.

SAL Offshore had to mobilize, including adding significant deck equipment and accommodation packages to one of its vessels, in just 10 weeks for a project to install a platform over a gas conductor well in a remote, challenging part of the Cook Inlet using a single vessel.

The Kitchen Lights Unit (KLU), operated by Luxembourg headquartered Deutsche Oel & Gas, sits in the Cook Inlet, home to just 16 production platforms, as well as strong tidal currents and range, dating back to 1964.

Furie, bought by a company owned by Deutsche Oel & Gas, discovered the deposit in 2011 and decided on a 1200-tonne monopod platform with 700-tonne topsides development concept in 30m water depth. The platform was built in Texas and transported by barge to the Cook Inlet where contractor Florida-based Crowley Maritime contracted SAL Offshore, based in Delft, Netherlands, to carry out installation.

SAL Offshore opted to use the *Svenja*, a Type 183 vessel built in 2010, with two, 2000-tonne combined capacity portside cranes. But, not before the 20-knot capable heavy lift vessel, was upgraded.

Working with Crowley, the *Svenja* had to be prepared in a shipyard in Singapore to add temporary living quarters for 60 supporting team members, plus 10 additional mooring winches, as an adjustable mooring system, and a 3D sonar system had to be installed.

Once on site, the team had to drive a king pile into the seabed using an 80-tonne Menck hydro hammer, then lift and "threading" the monopile exactly over the wellhead, using the king pile as a guidance to slide along into the depth. The work was done using purely sonar imaging, due to zero underwater visibility. Finally, after placing and grouting eight piles, the module support frame was installed, followed by the topsides and helideck. These procedures also had extremely tight tolerances, to meet crane outreach limitations and without touching any of the mooring lines.

What's fairly unique about this project is that the *Svenja,* equipped with a Kongsberg DP1 system, was the only construction vessel in the field for the work. It was also working in strong tidal currents, at 5-6 knots, and tight, four-hour, high tide installation windows – and 25ft tidal range.

Production began at the field in November last year. Deutsche Oel & Gas planned to continue exploration drilling in the Cook Inlet this year, using the newbuild Randolph Yost jackup, in order to double the amount of gas delivered this year.

SAL Offshore opened a Delft, the Netherlands, office in 2012. It is a subsidiary of SAL Heavy Lift, a K-Line company, set up in 1980 and based in Hamburg since 2013. SAL Heavy Lift has 14 vessels and 600 crew members, plus two charter vessels.

As well as oil and gas projects, SAL Offshore has been working on renewables projects, using the 160.5m-long, *Lone vessel* equipped with a Kongsberg DP2 system, delivered in 2011, and also with two portside 1000-tonne cranes.

On the Wikinger Wind Farm in the German sector of the Baltic Sea, SAL Offshore transported and installed nine, 36m-long, 1.4m-diameter, up to 47-tonne test piles using the *Lone* in up to 40m water depth. The firm then went back 10 weeks later to perform strike and pull out tests.

At the European Marine Energy Centre, at Orkney, Scotland, the firm transported and installed on a pre-installed monopile a 220-tonne Voith tidal turbine (Voith Hytide 1000-13). This was in high cyclic tidal range through which the vessel was able to operate while remaining within its DP2 operational limitations.

The firm's idea, for future array projects, is that it could stack 6-7 of the devices in the vessel's cargo hold, then stay on site and install several in one go, including substructure clump weights. **OE**

MV *Svenja* installing the topsides.

www.omc2017.it
OFFSHORE MEDITERRANEAN
CONFERENCE & EXHIBITION
OMC
2017
TRANSITION TO A
SUSTAINABLE ENERGY MIX:
The Contribution of the
Oil & Gas Industry
29-31
March 2017
RAVENNA
ITALY
18,000 visitors
688 exhibitors
1,200 delegates
REGISTER NOW ON
www.omc2017.it
OMC
CONFERENCE ORGANISER
conference@omc.it
YouTube
International
Exhibition
Services
EXHIBITION ORGANISER
exhibition@omc.it

The K5F-3 subsea all-electric Xmas tree from OneSubsea. Photo from Total E&P NL..

Electrifying

The all-electric subsea Xmas tree, complete with electric downhole safety valve, has finally made its debut. Elaine Maslin spoke to Total's Frederic Garnaud about the achievement.

This summer, a shallow water subsea well in the Dutch sector of the North Sea was brought online. While this might not sound significant, it is noteworthy due to the technology proved on the well.

The K5F-3 well has demonstrated the all-electric subsea concept, including a downhole safety valve (DHSV). Two earlier wells on K5F had all-electric trees – also firsts – but a hydraulic DHSV. Furthermore, the components involved have been qualified to 3000m water depth, making it a deepwater-ready technology.

The system uses Schlumberger-owned OneSubsea's latest generation CameronDC subsea Xmas tree and controls technology and a Halliburton electric downhole safety valve (eDHSV).

It's an achievement, towards reducing cost, simplifying the subsea system and enabling ultra-deepwater and long step outs, says Frederic Garnaud, deep offshore research and development program manager at French oil major Total. Once the technology has been observed working smoothly for a few months, subsea all-electric will become the base case for subsea control environments for Total deepwater developments, from 2017 forward, Garnaud says.

"The main benefit of electric control is in the cost reduction because the current technology for subsea control is based on hydraulic control, which requires a network of umbilicals, with electric cables and hydraulic and chemical lines," he says. "These systems are expensive, very complex, and difficult to install. There is a major cost saving through simplification or removal of the umbilical.

"Electric technology will also be an enabler for frontier developments in deepwater. The industry is beginning to pay some attention to water depths of 3000-4000m. There's no doubt, in such water depths, electrical control will be much easier to implement. It will really be an enabling technology. If you consider also long tiebacks, over 200km, there's no doubt as well that electric control will enable those developments."

By using all-electric, and eliminating hydraulics for power and signals, control-system commands can be sent in rapid succession, with high-speed communication also providing near-instantaneous communication with equipment – such as the status of the electric DHSV – as well as feedback on subsea conditions. Going all-electric also eliminates the potential for hydraulic leaks and the issue of hydraulic-fluid disposal.

Proving up an all-electric subsea tree became a goal for Total in the mid-2000s. It chose the K5F field in the Netherlands as its test bed, using the all-electric CameronDC technology, which Cameron as it was had been working on since 1999, for the gas development's two subsea wells.

A hydraulic DHSV was selected for the project because the eDHSV was not yet fully qualified and available for use at the time, Garnaud says. The two-well project, on a three-well template, was tied into the K6 platform, then on to the K6-P/L platform, about 20km away.

The system has largely proved itself, with 100% actuator reliability, but there were some glitches around the subsea control modules and the hydraulics system, according to Total.

The latter only served to encourage the completion of development of an eDHSV with Halliburton. The second phase on K5F, the planned K5F-3 well, kicked off in 2013, with ongoing work on the eDHSV. Halliburton's eDHSV uses electric linear actuators, adapted from its DepthStar DHSV. The subsea control modules were also upgraded, compared to what was on K5F.

The full system, tree and eDHSV, were fully assembled at OneSubsea's facility in Germany late 2015 and put through system integration testing before being shipped out for installation this year. The well was completed in mid-June, followed by perforation and then first production in early August.

"What we are doing in the Netherlands is a demonstration of subsea control technology for future assets in the deep offshore environment," Garnaud says. "All of the components on this well are qualified for 3000m of water, so the eDHSV can run in the Gulf of Mexico or the Gulf of Guinea in deepwater. "Each component of the Xmas tree is also qualified for 3000m water, so we can use it on deepwater applications as well," he says. Total has also been working on other building blocks for deep offshore developments, including subsea chemical storage. "With this we can completely remove the subsea umbilical," Garnaud says. "Just install electric power cables with fiber optic for control and that's it. By installing subsea electric control and subsea chemical storage you can save around 20% of the capex for facilities on the subsea satellite."

Another Total project, called SPRINGS (Subsea PRocess and INjection Gear for Seawater), is working on a subsea seawater injection system, which would enable removal of the need for water injection flowlines from the topside facilities. This would "save a massive amount of money," Garnaud says. It's about simplicity, "simplifying the SURF (subsea umbilicals, flowlines and risers) package," he says. And it's also about subsea technology cost reduction, which has been a strong focus for Total since before 2014.

But, it's still early days and that's largely due to needing more suppliers that are able to offer this equipment – and compete on tenders. "What is not really available today is the full range of demonstrators for valve control, actuators, the various pressure wrenches for the valves," Garnaud says. "What's also missing for real projects is competition among the technology providers. All of the major subsea suppliers, FMC Technologies, GE Oil & Gas, etc., are working on the subject but none of them has a full range of equipment today. What's important for us from now on is to promote competition in the technology so that, from 2017 on, we are able to launch tenders for full electric control of subsea assets."

While within Total there is an understanding of the benefits of this technology for deep offshore projects, the challenge will be persuading partners to embrace it as well. Even so, there's a strong trend towards all-electric across the industry, Garnaud says, following on from moves already made by the likes of the aeronautical industry – Concorde had first electric controls partially replacing hydraulics back in 1969, he says. In fact, the linear actuators on the eDHSV have been derived from aerospace, he says.

"Today, there's no question about electric control as being tomorrow's subsea control technology," Garnaud says. OE

The K6 platform.
Photo from Dufour Marco/Total.

Seeing the (electric) light

The Åsgard subsea gas compression system, complete with eActuators and electric process control valves. Image from Statoil.

While French oil major Total has demonstrated the first all-electric Xmas tree, Norway's Statoil is eager to do the same. Elaine Maslin examines the subsea all-electric initiative.

With cost efficiency and simplification high on the subsea agenda, all-electric subsea facilities are coming back under close scrutiny.

All the parts are in place. Subsea actuators have become established tools, Total has demonstrated a full, all-electric subsea tree, and Halliburton has qualified an electric downhole safety valve (eDHSV).

The will is also there. Statoil wants to achieve its own all-electric tree within five years, says the operator's leader of subsea technology within the research and technology division, at this year's Underwater Technology Conference (UTC) in Bergen.

Operators are keen on an all-electric subsea concept because it could remove the need to install hydraulic conduits, reducing cost. Yet, the path to the all-electric subsea tree has been a long one.

A long electric road

The first subsea well was in installed in 1961, in 17m water depth in the US Gulf of Mexico by Shell. It was direct hydraulic drive. In the 1970s, electric-hydraulic systems were developed, to enable longer distances for control than hydraulics could cope with.

The Norwegian Continental Shelf had its first multiplex electric hydraulic control system in 1986, on Statoil's Gullfaks satellites, says Bjørgulf Haukelidsæter Eidesen, leader subsea technology and systems, Statoil, at UTC earlier this year.

By the 1990s, work on electric actuators (eActuators) started, with Statoil using them in 2001, Eidesen says. On the Åsgard subsea gas compression project, the world's first subsea gas compressor, there are some 79 eActuators, Eidesen says, and worldwide running time of eActuators is above 8 million hours.

Achieving a full electric Xmas tree took longer, however. In 2003, BP, working with Cameron, developed the first all-electric subsea control system for a six-month offshore field trial at the Magnus field, in the UK North Sea, in 185m water depth. An "electric tree" – a set of valves and a choke on a skid – was deployed, not connected to a well, but pressurized from the surface and connected to the Magnus facility for power and communications. However, BP didn't take it much further.

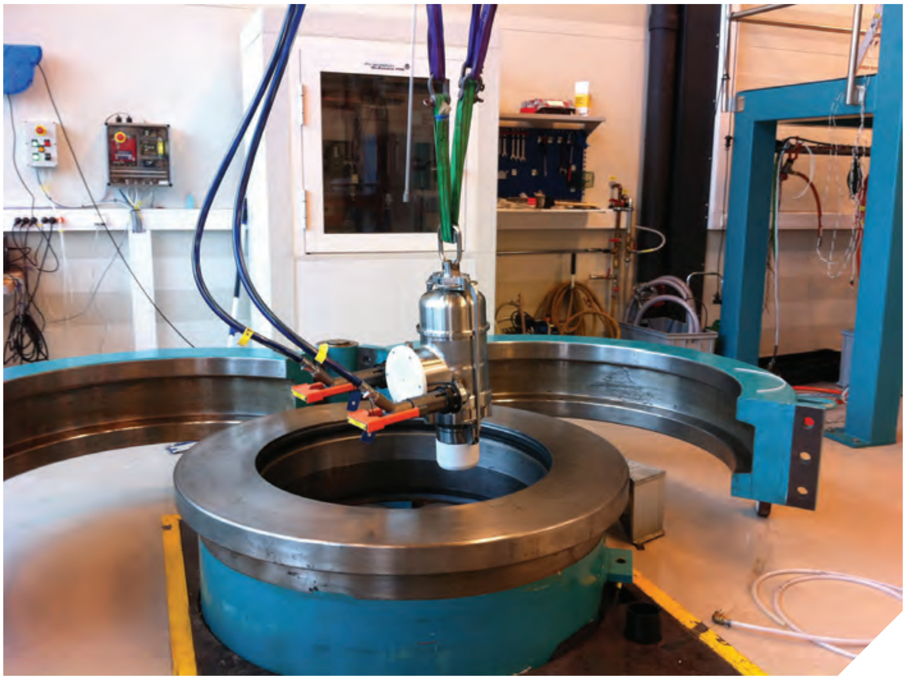
It wasn't until 2008 that the first all-electric Xmas tree system, with a hydraulic downhole safety valve, was deployed on two wells, in the Dutch sector. This summer, a fully all-electric system, including eDHSV was deployed on a third well at the same site (*see pages 38-39*). With electrical process control valves now proved on Statoil's Åsgard project offshore Norway, a full subsea system, qualified to 3000m water depth, is close at hand, says Frederic Garnaud, deep offshore research and development program manager at France's Total.

Why electric?

Christopher Curran – ex-BP, and now working as a contractor for several companies including Edinburgh-based wireless subsea instrumentation and control and communications firm WFS, and consultancy Endeavor Management – based out of Houston, was involved in the Magnus trial. He says there are a number of benefits to going all-electric.

"You don't have to keep filling the system with hydraulic fluid," he says. About a gallon of hydraulic fluid is consumed for every valve operation, points out Bjørn Søgård, segment director, business development, subsea and floaters, DNV GL."You don't have people standing around high pressure systems, especially when we're going to 15,000psi and higher," Curran continues. "You get an awful lot more data out of the system. You get more knowledge about the health of the system. You can get some real indication if you're having issues with a valve, actuator, from scale, waxing etc. You get very little information from a hydraulic actuator. And there is potential for savings on the umbilical side. Telecommunications cables are a fraction of the cost of an umbilical."

The time it takes to operate a valve is also shorter with electric, Søgård adds, due to the time it takes to get back to a steady state after each operation, with no phase lag. Removing the hydraulic elements, and even the spring failsafe, replacing it with a battery, would also reduce the size and, therefore, cost of subsea trees, as well as the cost to install them, which means smaller vessels could be used.



A hyperbaric test of Aker Solutions' subsea rotary electric actuator, simulating 4000m water depth. Photo from Aker Solutions.

Right timing

So, why has it taken so long and why the fuss now? Statoil assessed all-electric in 2009 for the Tyrihans field, but it was later canceled. At that time, Statoil found costs were too high, Eidesen says.

"A problem has been that everyone says electric and water do not mix, 'it's a bad idea.' If you look at an electric actuator and compare it to hydraulic, you could say it's too complicated," Curran adds. "But, then, if you look at the whole system – with a hydraulic power unit on the topside, etc. – in those days there was at least parity between the two systems in terms of reliability."

Another reason could be that the production control system is only about 2-5% of the total system cost, Curran says. Saving money there doesn't seem like it would make a big impact in the overall cost, so it wouldn't seem worth the risk.

There is also concern around the failsafe – the function that maintains the tree as a barrier to the reservoir, Søgård says. At the moment, mechanical spring failsafe hydraulically operated valves are used, something the industry is comfortable with. Hydraulic pressure holds the spring back, if the hydraulic fails, the spring closes the valve.

Going all-electric means either using a spring-based failsafe (API required), with a local electronic circuit, or a clutch solution, so that the open position is maintained using only a small amount of power, and use a battery as the failsafe option. Total's K5F-3 is using a spring failsafe, without hydraulics – more details were not available.

Søgård says that while an electric-operated failsafe is not hard to achieve, technically – "Xmas trees are simple compared to process equipment" – the simplicity and industry comfort with hydraulically actuated Xmas trees means a change in philosophy is needed to move to something else, not least because a well barrier is being dealt with. "We are in a way reluctant to put on something delicately engineered to take care of this safety function," Søgård says. Statoil's Eidesen adds that the Norwegian oil major is going to evaluate both options – a spring and a battery failsafe solution.

A subtler problem, as all-electric is adopted, could be that the industry falls into the trap of each vendor producing its own type of electric tree, before there are standards, Søgård says. "There is a lack of standards. Shall we use DC or AC? We don't know that. What voltage levels do we need? We don't know that. No one has agreed a common design so we end up with tailor made solutions."

Fast forward

Still, the industry is moving forward, partly driven by cost reduction, but also to help it move into deeper waters and to achieve longer step outs, as part of a wider all-electric system.

In 2014, even before oil prices plummeted, cost reduction was high on the agenda for subsea projects, not least in Norway. Operators are looking at how to simplify subsea systems, reducing the number of flowlines, umbilicals, connectors, etc. All-electric could help.

Indeed, in 2015, Norway's OG21 group published a report on subsea cost reduction. It said that in order to reduce subsea costs by 50%, an important technology step was achieving all-electric. In addition to achieving an all-electric subsea tree within five years, Statoil is also working towards a local hydraulic power unit subsea – due to be qualified this year – to power the 7in downhole safety valve, but ultimately, the firm wants to see a 7in eDHSV developed.

Furthermore, "Being able to lay a power and communications cable, not complex umbilicals, will save cost, especially for long distance tiebacks," Curran says.

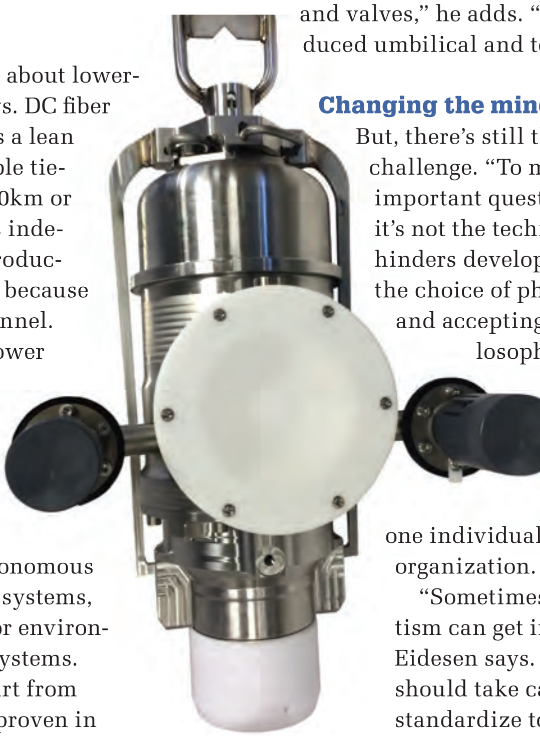
Statoil has done just this on the Johan Castberg development offshore Norway. It is planning to use a DC and fiber-optic cable in daisy chain to power the subsea wells at Johan Castberg (*OE*: August 2016), reducing cost and complexity.

Electric enabler

However, it isn't just about lowering cost, Eidesen says. DC fiber optic, for example, is a lean system that can enable tie-back distances of 300km or more, he says, and is independent of subsea production system supplier because it offers an open channel.

"It provides the power necessary to power electric actuated valves and even small chemical injection pumps," Eidesen says. "It can power AUV (autonomous underwater vehicle) systems, seismic cable grids or environmental monitoring systems. There's a lot to it apart from powering. And it is proven in telecommunications.

"In the case of Åsgard subsea compression, the process control of this system could not have been done with electro-hydraulic actuated valves, due to the high complexity and valves," he adds. "It also reduced umbilical and topside cost."



A high voltage subsea electrical actuator, from Aker Solutions.

Changing the mindset

But, there's still the mindset challenge. "To me the big, important question is that it's not the technology [that hinders development], it's the choice of philosophy and accepting new philosophies," Søgård says, which can often be driven by just one individual in an organization.

"Sometimes conservatism can get in the way," Eidesen says. The industry should take care not to standardize too much so that all-electric is hindered, he warns. Failsafe standards should also be written to enable a battery solution, he adds.

Another more practical piece to the puzzle is chemical supply for injection. Taking away the hydraulic umbilical is one thing, but you would still need chemical lines. However, a number of people are working on subsea chemical storage and injection, Curran says, including Total.

"We need to break the paradigm of everything being connected together by cables," Curran says. "With the advent of wireless systems and long battery life of up to 10 years, it is now much easier to add sensors later and gain the measurements you need."

Achieving the all-electric tree could open up new possibilities, he says. "Suddenly you step across this line and there are so many things possible that weren't possible before or were near to possible.

"It's about how to make subsea cost efficient at \$50/bbl, breaking the convention of having to have dual flowlines. It's also life of field extension, the ability to wirelessly recharge AUVs without having to dock to connectors, which WFS can achieve." OE

The conference will provide an in-depth view of the future of Mexico's growing energy sector, discussions of case histories, developing trends, best practices, new technologies, lessons learned and innovations. Critical insights and overview into the vision and strategies from key leaders in the industry will also be featured.

To be considered, please include the following with your organization's submission: presentation title, author(s) name, and contact information. Papers must be of value to delegates and devoid of commercialism.

2017 Conference Topics Include:

- New Technologies
- Case Studies
- Geophysical Challenges & Opportunities
- Production Technology
- Shallow & Deepwater Developments
- Shale Developments
- Drilling/Completion
- Subsea Technologies
- Market Trends and Strategies
- Health & Safety/ Environmental

Proposed topics are listed but areas to be covered are not limited to the outlined criteria.

If you are interested in submitting a paper, please contact Jennifer Granda at jgranda@atcomedia.com

For information on exhibit and sponsorship opportunities please visit:

www.pecomexpo.com

Produced By: OE Offshore Engineer · AOG ASIAN OIL & GAS

Organized By: ATCOmedia Atlantic Communications Media

A combined steel and electric cable umbilical.
Photos from Technip.

E-volving umbilicals

The move towards all-electric subsea facilities will precipitate an evolution in umbilical design. Alan Dobson outlines the challenges and what is already available for the market.

As the subsea oil and gas industry has been adjusting to a "lower for longer" oil price, it has brought into focus the potential costing saving opportunities subsea processing technologies could bring to future projects.

By treating produced fluids on the seabed rather than on the topside, longer distance transportation to either an existing host facility or to an onshore facility could make future projects economically viable. Some operators are facilitating development of this concept through research and development initiatives, for example, Total's DEPTH (Deep Export Production Treatment Hub) and Statoil's Subsea Factory. Class society DNV GL released its All Subsea study in order to develop, integrate and qualify key technologies.

Certain technology building blocks, either in isolation or combinations, are required:

- All-electric control
- Heated pipelines
- Subsea separation (water/oil, and gas/liquid)
- Compression/multiphase boosting
- Seawater treatment and reinjection
- Electrical power transmission

In terms of controlling and supplying essential fluids and power to the additional subsea equipment, the control umbilical must evolve to incorporate new functionality required by electric control systems and provide greater levels of electrical power transmission.

Impact of all-electric control on the umbilical

The first subsea trees with all-electrical control were installed in the Dutch North Sea in 2007. Although in this application the hydraulic downhole safety valve was retained, all other actuators on the trees were electrically powered. Future deployment of all-electric systems will more likely use electric downhole safety valves, such as those now being trialed in the field *(see page 38)*.

The fluid functionality of the umbilical will be simplified as the hydraulic power supply and return is no longer needed. This will benefit extremely long tieback umbilicals because hydraulic power efficiency diminishes as lines get longer, leading to higher costs for larger bore tubes working at a higher operating pressure.

Although electrical transmission also suffers losses over longer distances, this can be eased by switching from conventional AC (alternating current) power supply to a DC (direct current). This change opens up the choice of cable construction to include coaxial designs and umbilicals have been supplied incorporating this type of DC coaxial cable.

As future deployment of all-electric control systems is likely to involve very long tiebacks, the control umbilical will remain a critical component that must be engineered for the operating environment.

The design and analysis tools developed by the industry for conventional AC cables have been adapted for DC cables and successfully proven through project experience. Subsequent deployment on further projects mean it can be considered a mature technology. Umbilicals will also retain fluid conduits to provide service fluids such as scale and hydrate inhibitors, methanol injection and also barrier fluids for pump motors. The cost of these conduits can be optimized by utilizing alternative construction methods, materials and efficient manufacture.

Assembly of these extra-long length umbilicals requires specialist assembly machines with large capacity bobbins to maximize component lengths, minimizing the number of welds and splices, leading to greater reliability. However, the ultimate length limit of a continuous umbilical is generally driven by the installation vessel carousel capacity and potential weather window restrictions.

Field proven factory fitted inline joints allow lengths of umbilical delivered on reels to be efficiently joined during offshore installation into a long-length tieback. They are fully factory tested before deployment, ensuring reliability and enable schedule flexibility during the installation campaign where partial lengths can be laid, maximizing available weather windows.

Subsea power

Of the other key technologies, heated pipes, pumps and compressors all consume high levels of electrical power, meaning increasing numbers of medium voltage three-phase power cables in the umbilical. This brought additional design challenges in terms of electromagnetic balance, temperature and structural integrity, for which solutions have been developed and qualified in readiness.

High power three-phase cables generate heat and all umbilical components need to be designed and materials selected to handle continuous operation at elevated temperatures. This could impact material yield strength, fatigue capacity or accelerate long-term aging. Thermal analysis models have been developed and validated, which enable accurate assessment of in-service conditions. Coupled with knowledge of long-term material behavior at temperature, this ensures design life reliability.

The electromagnetic radiation emitted by three-phase power cables needs to be carefully understood, again through detailed analysis, and components positioned accordingly to minimize electrical losses and induced voltages on metallic components. If neglected it could result in high transmission losses, accelerated corrosion of metallic components or cross talk of signals onto control cables. Recent advances in higher pressure, deeper water thermoplastic hoses, that can operate continuously at higher temperatures, offers an alternative solution to steel tubes without the thermal and induced voltage concerns.

With increasing amounts of copper cables being required, the weight and strength of the umbilical assembly becomes a concern. Copper has a high density and low mechanical strength, which can pose challenges during installation, particularly in deepwater. Aluminum cables offer a solution, where the reduced weight and greater strength significantly increase the installability of the umbilical and reduce material cost.

Summary

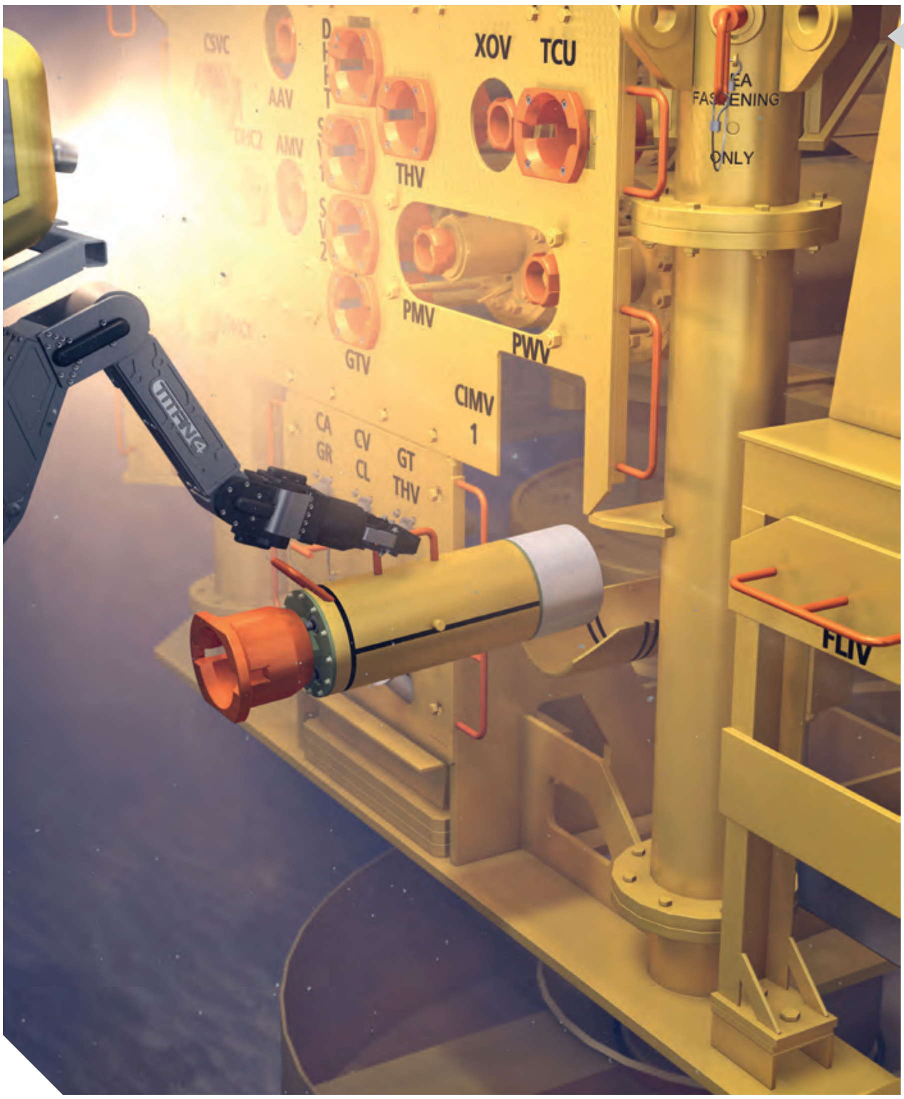
Umbilicals will continue to be a key component of the subsea infrastructure as the industry collaborates on placing more subsea equipment on the sea floor. Cables to support all-electric control have been designed and proven. Solutions are available to competently transmit greater levels of electrical power. Efficient manufacture of extra-long length umbilicals can be reliably performed and use of factory fitted mid-line joints can provide cost benefits during installation. OE

Alan Dobson is vice president of research and technology with Technip Umbilicals. He has worked in subsea technology for over 20 years, developing subsea robotic systems, cable and fiber-optic trenching technologies and, in his current role, several umbilical technologies focused around subsea power, chemical injection and control.

Dobson has a PhD in subsea control and automation from Newcastle University. He is also a chartered mechanical engineer.

Technip Umbilicals R&D Center

Point of no return – **injection accuracy**



In the subsea environment, accuracy of inhibitor dosage is paramount. The PULSE LF CIMV increases flowmeter accuracy and inhibitor dosage. Image from Schlumberger.

The dawn of ultrasonic flowmeter technology increases chemical dosage accuracy, says Cameron's David Simpson.

For low-dose inhibitor (LDI) injection on long step-out, deepwater tiebacks or satellite wells, the subsea chemical injection metering valve (CIMV) is the point of no return. Pinpoint accuracy of injection is not only critical to achieving full inhibition, it can save operators from pumping large volumes of excess chemical over the life of the field just to protect from chemical injection flowmeter inaccuracy. A typical field in which LDIs were injected at 2 L/h into 12 wells over a 20-year field life could become over injected by as much as 3-4 million liters of excess chemical based on the selection of CIMV technology.

In long step-out deepwater projects with complex system architectures, LDI injection and control can be problematic. Subsea distributed chemical injection is often best suited to address the flow assurance challenges of these wells, but requires greater control and accuracy over levels of LDIs being added, at multiple points, into the flow.

Effects of incorrect chemical dosage

Problematic and costly repercussions can occur should the inhibitor dosage be over or under the optimum application rate. Reasons for under- or overdosing are often tied to chemical injection flowmeter accuracy, which can be heavily influenced by the properties of the injected chemicals. Under injection of treatment chemicals can result in scale or paraffin buildup in well production strings or pipelines, lowering the production rate. If the scale or paraffin exist in the line for an extended time period, the well may have to be shut in to undergo a batch treatment, incurring deferred production and intervention costs. Where corrosion inhibitors are being injected, subsea umbilicals, risers, and flowline (SURF) facilities can, in severe cases, be taken offline until failed components are replaced.

In the case of overdosing, chemical excess costs can be significant and the additional chemical tanks take up valuable deck space on the platform. For instance, a company could spend more than US$1 million to overinject just one well over the life of the field. Furthermore, excess levels of LDIs in the export crude may affect its value at the refinery. Over the life of a field, accurate flow measurement and control of LDI injection could reduce operational expenditure by tens of millions.

The challenges of metering LDIs

With LDI injection, particulate blockage is a recognized cause of CIMV failure; this blockage is partly caused by the extremely low required injection rates, sometimes less than 0.5 L/h [3.17 gal/d] and the fact that particulate contamination can be introduced into the chemicals during transport, storage, and subsea distribution. These particulates can block moving parts inherent to many flowmeter and CIMV designs.

Traditional flow measurement technologies used in subsea chemical injection metering valves typically use Venturi-type flow measurement. Inaccuracies in flow measurement can stem from particulate contamination and blockage in the CIMV and from the fact that CIMVs are engineered years in advance of being put into service, often with limited knowledge of the chemicals to be injected. Such events render the CIMV as being not properly tailored for the chemicals being used, and ultimately, potential system under performance occurs.

A new dawn in CIMV flowmeter design

The latest low-flow CIMV flowmeter design delivers accuracy better than +/-2% of reading for LDI injection compared to the industry standard Venturi-type flowmeter that may only deliver accuracy of 5-10% full scale. Launched at OTC 2016, the new Cameron PULSE LF low-flow ultrasonic chemical injection metering valve features a microbore nonintrusive, line-of-sight ultrasonic flowmeter. Featuring no moving parts, the flowmeter delivers debris-tolerant flow measurement, is chemical independent with a very low native pressure drop, and does not require subsea filtration. Developed to address the complete LDI chemical injection portfolio from 0.25 L/h to 600 L/h [1.6 to 3800 gal/d], this flowmeter is combined in closed loop control with a throttling valve, providing a self-regulating device requiring only one user-defined input—low rate.

The PULSE LF CIMV's flowmeter addresses the key limitation of present LDI chemical injection technologies—sensitivity to blockage. The flowmeter is particulate tolerant, meaning that contaminated fluid can easily pass through the unrestricted flowmeter tube. It also provides consistent high accuracy of reading independent of changes in chemical properties such as viscosity, and reliably measures chemical inhibitor flow rate. Real-time feedback from the flowmeter enables autonomous control of the throttling valve, maintaining a user defined injection rate set point indefinitely regardless of up- or downstream system disturbances.

Packaged as an ROV-retrievable device with onboard diagnostics, the PULSE LF CIMV enables full inhibition without the risk of under- or overdosing. Operators now have the option to reliably deliver LDIs via cost efficient subsea distributed chemical injection systems with precision regardless of chemical properties or contamination, giving them the option to make chemical decisions independent of the installed hardware. OE

***David Simpson** is the subsea product manager for Surface Systems, Cameron, a Schlumberger company, a position he assumed in 2008. With 19 years' experience, he has worked offshore, in product design as principal subsea choke design engineer, as a technical account manager, and in product management. He launched the Cameron initial low-flow CIMV technology in 2007, and the third generation medium- and high-flow designs in 2010. Simpson is a chartered engineer with an honors degree in mechanical engineering from the Dublin Institute of Technology.*

The power to connect

High-performance subsea cables and umbilicals to connect the global offshore energy industry.

In the world's harshest environments and ever-increasing water depths, JDR's world-leading products and services bring power and control to offshore oil, gas and renewable energy systems. For more than 20 years, we have built our success on our technical expertise and reliability. Every market we enter, every customer we serve, and every project we deliver benefits from our dedication to technical quality, service and support.

Visit jdrglobal.com to find out more.

Old fields, new tricks

Left: The Britannia BLP.
Inset below: Britannia and the long term compression module. Photos from ConocoPhillips

Time and greater understanding makes most people and companies look at projects and assets differently and it's no different for oilfields. Elaine Maslin reports from Devex.

In the North Sea, there are plenty of mature fields ripe for a fresh look, even in today's low price environment. Taking a new look at oilfields, whether it is because they need a new export route or because past interventions haven't quite done the trick, was a common theme at this year's Devex conference in Aberdeen.

BP outlined how it's brought new life to the Monan field and ConocoPhillips described the epic journey the Britannia complex has been on.

Ugly ducking

BP's Monan field, a subsea tieback to the Eastern Trough Area Platform (ETAP) was the ugly duckling in the attractiveness stakes last year, until the firm took a step-wise approach to the challenges around bringing it back online. It then became one of the most attractive projects for the business last year, said Marianne McKevitt, petroleum engineer, BP, at Devex. It also become the first time BP retrofitted gas lift technology using a light well intervention (LWI) vessel.

Monan was discovered in the central North Sea in 1990 and started production from two wells, 130 and 131, in 1998. Artificial lift wasn't originally considered for the field, brought online during CRINE (cost reduction initiative for the new era), and initially it had good stable producers. But, production rates declined rapidly. By 2001, well 130 was lost altogether and well 131 struggled to maintain a stable flow.

By 2014, after coiled tubing interventions in both wells in 2001 and again in 2008, including retrofitting gas lift on well 130, both wells were offline, with downhole safety valves stuck in closed position. "It was going to take significant investment and a number of complex activities to reinstate the wells so it didn't look very favorable as an opportunity," McKevitt says.

However, a look at data from well 130, to look at well 131, suggested there was a significant prize making it worth a try. So, the firm took another look on the basis of performing a reinstatement project, including retrofitting gas lift.

"The key issues were: we didn't understand if we could reopen the downhole safety valve; we had a complex well trajectory to begin with; well access issues – well 130 had history; we were unsure what we were going to see – it was more than 14 years since we were last in the well so there was uncertainty," McKevitt says. "We needed to assess if well 131 had the necessary well integrity requirements for a change of service to gas lift. We also needed to understand if the well could be configured for gas lift by punching the tubing and setting gas lift straddles as we didn't have the luxury of side pocket mandrels. We also knew a rig wouldn't work based on cost. The key to doing this project was doing it off an LWI vessel."

Reinstating the wells would require: on well 131, repairing hydraulics and de-isolating the well, replacing the subsea control module, retrofitting gas lift and adding perforations to improve productivity; on well 130, the key task was to restore downhole safety valve functionality.

Diagnostics on the well 130 downhole safety valve using a LWI found the issue was subsea and not downhole, so the subsea control module was replaced using a dive support vessel (DSV).

While the operation to add new perforations on well 131 was held up due to solids in the well, contingencies put in place for scale wash and milling helped the project go forward. Gas lift was then successfully retrofitted using a LWI. On the second stuck downhole safety valve, the hydraulics were fixed using a DSV.

"Unfortunately, well 131 didn't clean up as much as we had hoped, but combining it with the fact that we came in well under our P50, the economics are still favorable, the pay back is just a bit longer," McKevitt says.

Key to delivering the project was taking a step-by-step approach, managing risk and cost exposure through phasing the project activities and pre-planning contingency options, McKevitt says. Most crucial was being able to retrofit gas lift off a LWI, something which BP had never done before.

Late life planning

The Britannia facility might be moving into a late life phase, but operator ConocoPhillips continues to look for ways to extend its life, aided by a renewed business focus.

Britannia was operated through Britannia Operator Ltd. (BOL) – a joint operating company and the first of its kind in the North Sea – with ConocoPhillips and Chevron as the 50:50 owners. However, in August last year, ConocoPhillips acquired the shares from Chevron, and BOL (now known as ConocoPhillips (UK) Britannia Ltd.), became a wholly-owned subsidiary of ConocoPhillips.

Discovered 41 years ago, Britannia, sitting 200km northeast of Aberdeen in 140m water depth, is a very different asset, said Rachel Preece from ConocoPhillips, at Devex. With asset maturity and increasing third-party processing complexity, both parent companies embarked on an asset performance review in 2015 resulting in the recommendation for a new operating model.

The Britannia field, one of the largest gas condensate fields on the UK Continental Shelf, was discovered in 1975 by Conoco, now ConocoPhillips. Yet, it didn't come onstream until 1998. It wasn't until 1990 that the field was confirmed as a single accumulation – by which time some 22 wells had been drilled by multiple operators. The field was named in 1991, in 1994 the field equity was agreed and the field development was approved.

At the time, Britannia was the largest substructure in the North Sea. It had the longest flowline tieback and was the first to use heated carrier bundles to prevent hydrate formation.

The field came online in 1998, via an eight-legged jacket topside. Two years later plateau production was reached at ~800 MMscf/d, meeting some 8% of UK gas supply at the time.

Yet, that was just the start for Britannia. In 2008, the Britannia Satellites (BritSats) project started up, involving the fabrication of a four-legged bridge-linked platform to the main facility, to tie in the Brodgar and Callanish fields, with Enochdhu added in 2015, and the Britannia Long Term Compression (LTC) module (currently the UK's largest low pressure compression module) in 2014. This year, first production is expected from the Alder high-pressure high-temperature field, a new tie-in.

"Britannia production has exceeded expectations year-on-year," Preece said. In total, there are now 47 platform wells, plus nine subsea wells on Britannia, three on the Brodgar field, four on Callanish, and one on Enochdhu, with Alder due later this year. But, while ~2.6 Tcf of the 4 Tcf in place in Britannia has been produced, and some plugging and abandonment work started last year, Preece says that there is still some way to the ultimate recovery goal. Last year, production was about 200 MMscf/d.

"As production from the platform declines, we still have some tricks up our sleeve as we move towards late life strategies," she says. "Our focus is on effective reservoir management and production optimization techniques, including the use of an offshore petroleum engineer to optimize well uptime and LTC."

There have been plenty of challenges with lessons being learned on the way. The asset spans four blocks and subblocks, and without a single operator, it was difficult to find focus for this cretaceous gas condensate development. "Through targeted acquisitions, we reduced the number of co-venturers from over 30 to three, and with our subsurface understanding being key to the asset value, we are now continuing to test new methods to further develop this," Preece says.

Having a joint operating company meant getting the best at the time from the two international operators. Now, with ConocoPhillips becoming operator and the move to an integrated operations strategy, it has further reduced complexity and succeeded in a 10% opex reduction in Q1 2016, Preece says.

But, the reservoir management strategy continues and the company is still looking at infill drilling and nearfield opportunities.

The Britannia story, like Monan, will continue. OE

BP's ETAP facility. Photo from BP.

The *Skandi Constructor*, used on the BP Monan project. Image from Helix Energy Solutions.

Heerema Marine Contractors used the *Thialf* to install Culzean's wellhead platform jacket and access deck in April 2016. Photos from Maersk Oil.

A 21st century platform

Applying digital technology to the Culzean HPHT development could provide efficiency savings of at least US$10 million per annum and introduce the iPad and tablet as standard offshore equipment. Maersk Oil's Troels Albrechtsen explains.

Maersk Oil's flagship development in the UK, the high-pressure, high-temperature (HPHT) Culzean reservoir, is quickly approaching a major milestone with drilling due to commence later this year. Culzean was the largest hydrocarbon discovery in the UK North Sea in over a decade.

The field is approximately 145mi east of Aberdeen and reaches temperatures of up to 175°C, and pressures of some 13,500psi, which is equivalent to being 9km under water. At its peak, from its three new, bridge-linked platforms, it is expected to produce between 60,000-90,000 boe/d for at least 13 years.

Developing an HPHT reservoir brings many unique challenges – a lot of specialist skills and equipment are required to drill HPHT wells, for example. And with fewer than 100 HPHT wells producing around the world, compared to thousands of normal pressure, normal temperature (NPNT) wells in the UK Continental Shelf alone, it can be considered a specialized market.

In this respect, we were facing a double challenge when we approached the design stage of Culzean – the task of developing a complex reservoir in a specialized market paired with a volatile oil and gas prices. We quickly understood that in this environment where (oil and gas) prices are expected to be "lower for longer," creating the ability to minimize the cost of operation once in production could be a big opportunity. We decided that harnessing technology would do the best job in helping us to address this opportunity and ensure efficiency is integrated at every stage of the design phase.

Digitization of Culzean

Because of the nature of HPHT developments, Culzean could not be fully automated, so we have embraced technology that ensures we will have the minimum number of people offshore. This will allow roles that would traditionally have been on the platform to be onshore, working in a real-time collaborative environment. The driver behind that is risk mitigation – the highest industry risk is helicopter transportation, so the fewer personnel offshore in total, and the fewer flights the better.

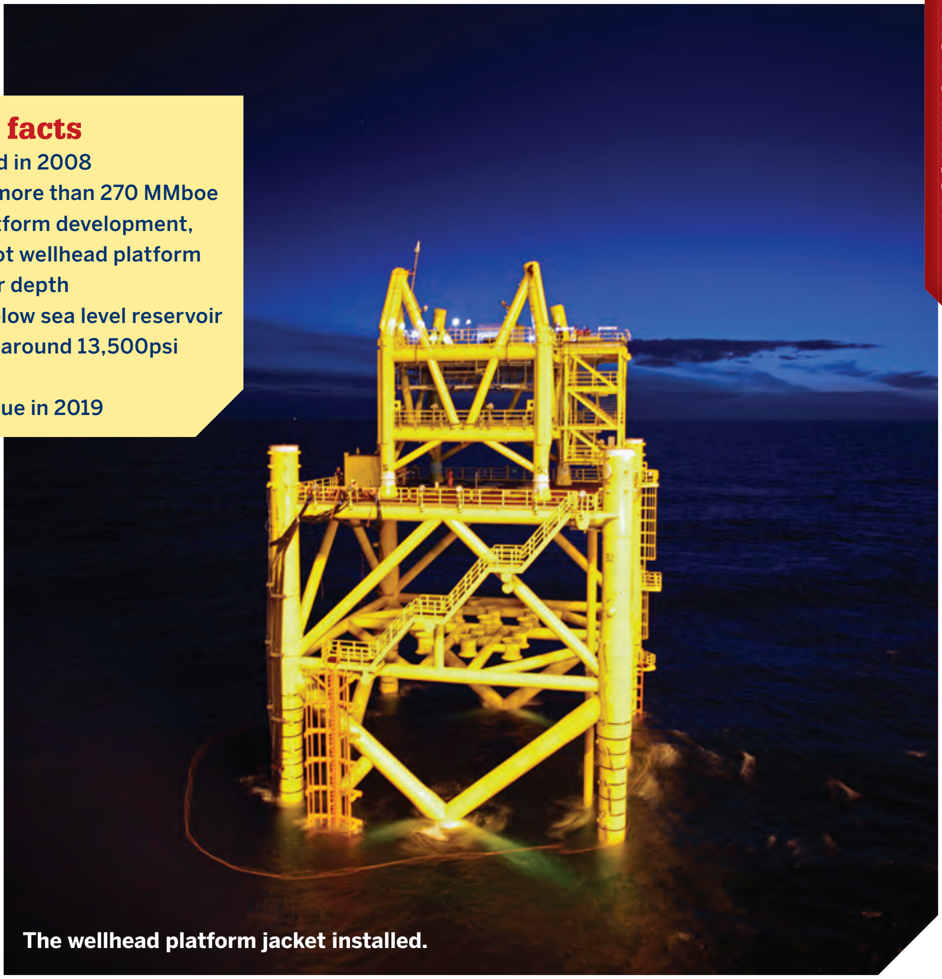
We decided to utilize relatively new, but available technology to build a 21st century facility on Culzean. While this meant making an up-front investment in facilities such as subsea fiber-optic cables and robust secure Wi-Fi networks, we know that these technology enhancements will pay off over the long-term by optimizing production efficiency, boosting uptime and running a safer, more reliable plant.

The volume of data our digitally enabled platform will generate demands a subsea fiber-optic cable, which allows for instant distribution of critical data from offshore operations. It will mean we can benefit from our own, and our key equipment vendor's global expertise while keeping them onshore. This has the power to revolutionize operations offshore, to enable faster and improved decision making, and to increase efficiency and major cost savings. It will allow us to remotely monitor critical equipment 24-hours a day, and enable offshore colleagues to access real-time data, immediate technical evaluation and onshore support.

It is estimated that up to 20-30% of an offshore operator's time is spent seeking data to perform a task. That's hours every day looking for work sheets, valve specs and procedures. Better data management on the worksite can significantly reduce this by providing real-time information. To enable this, Maersk Oil will attach radio frequency identification, or RFID, tags to critical equipment on Culzean, which will provide the operator with all information associated with a piece of equipment in real-time. The information will include manufacturing data and certificates, drawings, video simulation of maintenance and operations activities, maintenance history and so on.

Culzean facts

- Discovered in 2008
- Contains more than 270 MMboe
- Three-platform development, with 12-slot wellhead platform
- 90m water depth
- 4300m below sea level reservoir
- 176°C and around 13,500psi reservoir
- First gas due in 2019



The wellhead platform jacket installed.

The operator will also be able to perform a maintenance routine by completing a procedure prompted by a checklist on a tablet. As the decks of Culzean will be flooded with Wi-Fi, any areas of non-compliance are instantly synchronized, with the master dataset and automatic notifications posted to the relevant operations management and support teams on and offshore. The operator can share photos and comments and these can be associated with the task and stored for future reference. Any actions generated are assigned a priority dependent on the criticality of the equipment and closure is tracked using standard reporting dashboards.

The full potential is still being mapped out. But when it comes to managing quality – in terms of being absolutely certain that the critical component being ordered is exactly what you need, especially when you're dealing with HPHT equipment – that alone is going to reduce unplanned downtime and means better production efficiency over the coming decades. That cash flow really adds up.

This is just the beginning

Applying these digital enhancements to Culzean could provide efficiency savings of at least $10 million per annum, as the iPad and tablet joins the wrench and screwdriver as a standard piece of equipment on the North Sea developments of the future. The digitization of Culzean also opens up opportunities for the adaptation of other exciting technologies in the future.

For example, engineers are currently exploring the use of augmented reality (AR) on offshore platforms. AR is constantly evolving and could unlock the potential of both our physical working environments and the people who work in them. I can easily see a time where all offshore workers have AR software installed in their goggles and helmets to help them navigate the platform more safely. From showing potential hazards or the shortest escape routes on the platform, to displaying messages about the status of the equipment, plus providing data on the pressure and temperature of pipes and wells or even digitally identifying engineers new to the platform. If we embrace digital technologies from the start, the possibilities are endless.

It's an area we keep track of as part of our drive towards increased automation and digitization as a means to strengthen our efficiency and safety. Culzean will be designed to work with innovative technologies like augmented reality.

And now is the right time to be thinking hard about new innovative approaches and putting in place sustainable working models which offer some protection against the cyclicality that is a fact of life in this industry. The challenging environment we're facing as an industry, forces us to develop more long-term plans and ensure we evolve our working practices to become more robust for the future. OE

Troels Albrechtsen *is senior vice president and head of corporate technology & projects at Maersk Oil. He joined Maersk in 1991 as a geologist and has gone on to hold roles including head of production development, head of UK Exploration and New Business, head of ExNB for West Africa and South America, head of projects and services, exploration and new business, and head of geology.*

FURTHER **READING**

Taming Culzean
oedigital.com/component/k2/item/10928-taming-culzean

Sound advice

Being able to see what is happening downhole real-time is one thing. Having the subject matter experts on the job, see the same data, as well as predictive analysis and all helpfully visualized, from wherever they might be, is another. BP and Kongsberg have been working on it. Elaine Maslin found out more.

The 21st century world is becoming ever interconnected and automated. It could be argued that space and military technology are leading the way.

In the military, drones are flown over remote regions by pilots sitting in offices on a military camp the other side of the world. At another location, expert facial recognition staff assess the images the drones gather. Both sites are then linked via satellite to a mission commander at another location, who is liaising with a superior elsewhere, and, in turn, consulting a defense minister, etc.

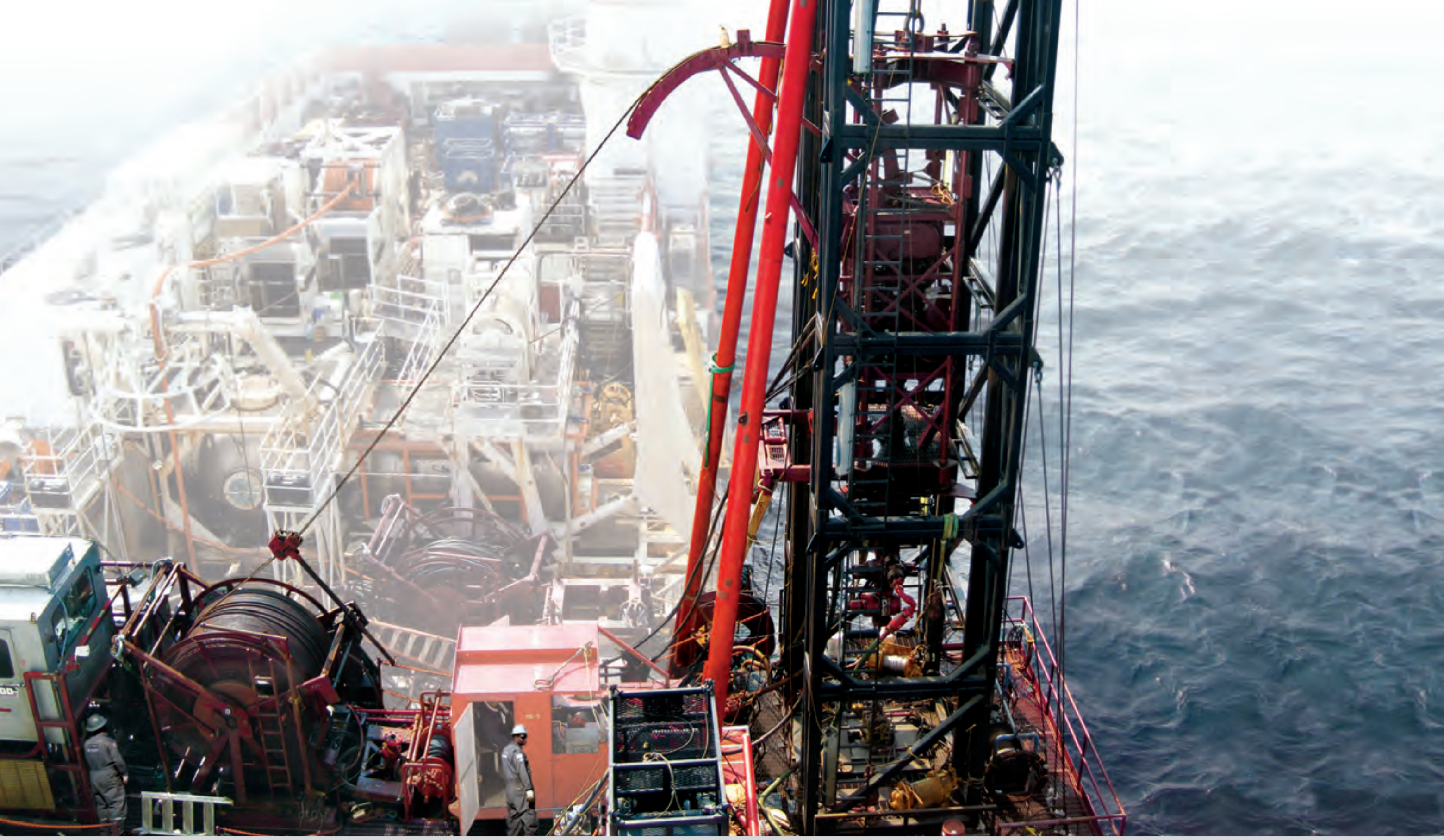
Thanks to today's communications technologies, they're all connected. They're all able to see the same information at the same time and then make decisions, drawing on live analysis from the subject matter experts as well as real-time live data and visualizations.

It's a world the oil industry isn't too far away from emulating. BP and Norway's Kongsberg have been working together for several years to develop something similar – it's just that it's for optimizing well construction operations, not military operations.

By the end of this year, the BP Well Advisor project will have seen the creation and deployment of a suite of 11 "consoles," which integrate real-time data with predictive tools, processes and knowledge from subject matter experts to help and improve efficiencies and reduce down time on a range of activities from casing running to tripping and remote BOP pressure testing. Some use similar "widgets," such as a 2D wellbore visualization tool, and all have been created by mining BP's specialists to create operational specific tools that have then been put through iterative testing and trials in real world situations.

It's not just about offering visualizations, says John Wearing, Kongsberg Digital's Houston-based president. These tools provide a wide range of workflows across drilling operations, with built in business logic and business flow processes, presented at the right time, in one common framework.

Shedding light on drilling operations. Photo from iStock.



INNOVATION MATTERS

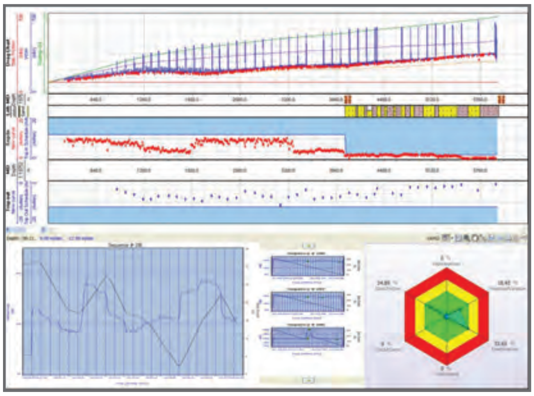
DELIVERING RESULTS BEYOND YOUR IMAGINATION

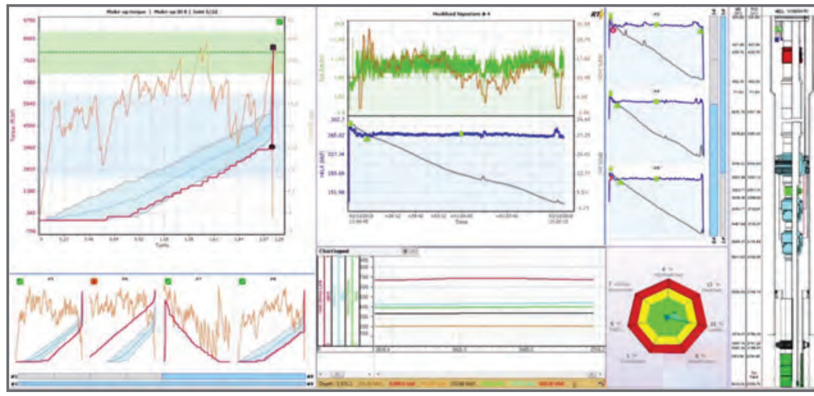
At Cudd Energy Services (CES), we use unconventional thinking to solve unconventional challenges. When our client faced a challenge that required repetitive rig ups and rig downs, we delivered a patent-pending, coiled tubing solution. CES eliminated costly steps, increased operational efficiencies and improved personnel safety on the job. The possibilities are endless with ingenuity and experience.

To learn more, visit us at www.cudd.com today.

CUDD ENERGY SERVICES

PROVEN EXPERIENCE. TRUSTED RESULTS.®
WWW.CUDD.COM





Left: The Casing Running Console increases situational awareness during the casing running process where stuck casing incidents and sub-optimal placement can contribute to costly non-productive time. **Right:** The Completions Console supports the real-time transmission of the connection make-up torque data for analysis by completion engineers. Images from Kongsberg.

For example, using the casing running console, the first of which were rolled out in 2013, some US$200 million was saved by 2015, thanks to this console being able to prevent stuck casing incidents, and that figure is now up past $300 million, says Ken Gibson, BP's wells technology manager. The system has been rolled out to some 28 rigs globally with some 1400km of tubulars run with no stuck tubular incidents, he says.

"There's a terrific amount of real-time data that exists from any well construction operation," Gibson says. "The realization, in today's volatile oil business, was that anything we could do to reduce inefficiency in these operations, improve assurance and well integrity of the well plus monitor critical equipment, such as BOP stacks, should be targeted."

Roll the clock back and this collaboration between BP and Kongsberg started even earlier. In 2007, BP started using Kongsberg's SiteCom, a system which acquires, stores and aggregates real-time drilling data. This then gets visualized in SiteCom Discovery another Kongsberg tool. BP had, however, for some time been looking at where and how real-time data utilization could evolve and decided to take the next step.

"By monitoring real-time results, visualizing certain parameters, comparing that with a prepared plan of what should be happening, you can see when you get a significant deviation," Gibson says. "You have the ability to see if something isn't right and you are able to stop and assess if you should continue or need another solution. In casing running, you could, for instance, be getting higher than anticipated drag forces. You could decide to proceed or pull the casing the string and clean the hole prior to re-running, stuck casing events are costly in both time and money."

The casing running console was developed first as a proof of concept. The real-time data required existed, as did the in-house algorithms looking at hook-loads, drag and pick-up weights of the string being run. Bringing all of this together into a live system with data visualization wasn't.

A lot of work has been done to build infrastructure to analyze and visualize this data in real-time. "We have worked with technical specialists within BP, defining the console objectives, what the information we need to see is and how it needs to be seen so it is useful in decision making," Gibson says. "A specification is compiled, Kongsberg develop the software which is then tested and subject to field trial."

The casing running console provides real-time monitoring of casing, liner and completions running operations, as well as early warning indicators that helps reduce stuck pipe incidents and mud losses. It includes an automated drag chart, detection of static friction, trip schedule versus actual running speeds, hook load warning indicators, and a hook load signature showing calculated values of interest.

Having developed and proved the casing running console, the project moved on to the next 10 consoles, including; cementing; pressure testing; BOP monitoring; rig site fluid management; no drilling surprises (displays correlation to sub-surface boundaries, zones of overpressure, and pre-drill risks); rate of penetration, drilling operations (well bore stability and hole cleaning); tripping; completions; and remote BOP pressure testing.

Development of the BP Well Advisor consoles will be complete by end of 2016 and so attention is focused on deployment of the consoles globally and transition to sustaining operations.

The tools are deployed to the regions most suited to them and where there's a particular job that would benefit from the support of a subject matter expert, they can be drawn in, remotely.

"One of the advantages is anyone [given access] can look at the same data." This enables "shared situational awareness," Gibson says. "You can have onshore personnel in Houston or Sunbury plus operations personnel in the field (both onshore and on rig) all looking at the same data. This replaces phone calls to transfer information and associated interpretations, which hopefully leads to better decision-making."

For Kongsberg, the next step is to take similar tools to the wider market, as SiteCom WellAdvisor. The capability to develop consoles for pretty much anything anyone wants is also available, Wearing says.

Yet, it's still not that easy to get technologies such as these deployed. First there's the business case. But, then there's also the human pushback, from staff who're comfortable doing it how they've always done it.

"One of the things we were actively looking at a few years ago when we initiated consoles, would be making them available to everyone and anyone," Wearing says. "The realization was that certain consoles lend themselves very well to 24/7 monitoring type environment, where certain people monitor them every day from one location, i.e. Houston. This could be certain high-risk wells. Then the consoles can also be used as an alert to say something is outside certain parameters and the expert can then assist decision making. It becomes more efficient." Indeed, in the future the system could even move from an advisory system to something more automated. OE

The South American offshore boom

The South American offshore market is back on the heat map, due to Exxon's major Guyana discovery and Statoil's interest in Brazil's Carcará, says Rystad Energy's Kjetil Solbraekke.

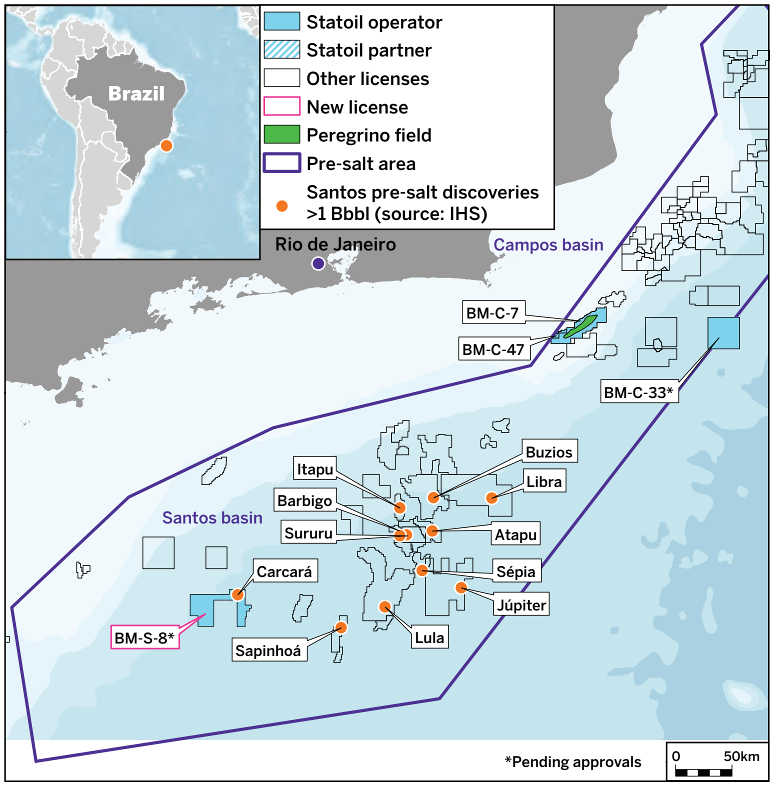
Things are heating up in South America. Exxon has confirmed the giant Liza discovery, offshore Guyana, and is expected to fast track the project towards sanctioning in 2017. Together with recent news that Petrobras' divestment process has finally commenced on the Carcará discovery, with a sale to Statoil for US$2.5 billion, increases the expectations towards the offshore market in South America.

Liza is the northern most discovery on the Atlantic margin that runs from Northeast Brazil towards Guyana. This billion-barrel discovery together with approximately 20 upcoming deepwater exploration wells along the Atlantic margin in northern Brazil over the next 4-5 years shows significant potential for new discoveries in South America. Liza is the first field to be developed along the Atlantic margin, and it illustrates that offshore South America is much more than just pre-salt in Brazil. Potentially, the Atlantic margin will open up a new multi-billion barrel play in South America.

Statoil took over as operator of the Peregrino field (FPSO pictured), offshore Brazil, in 2008. Photo from Statoil.

Brazil Offshore

Nonetheless, there is also a very positive development in the pre-salt region. It is now 10 years since Petrobras discovered 8 billion bo in the Lula field, which is under 1000m of fossil salt in ultra-deepwaters off Brazil. Since then, Petrobras has found an additional 30 billion bbl, and some 15 billion bbl of pre-salt oil are now developed. This is only taking into account the part of the discoveries that are within the existing concessions and production sharing agreements (PSA) [Libra]. However, it is also well-known that significant volumes from existing discoveries expand into open or non-licensed areas, and this is expected to be the focus for the next license round in Brazil, also called the "Unitization Round." However, it is assumed that before such a round can take place, the Brazilian government has to make some important adjustments to their petroleum policy.



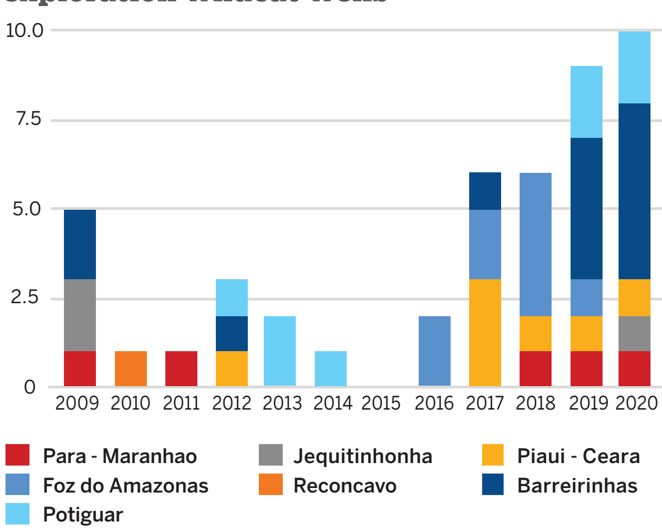
Map of Brazil offshore. Image from Statoil.

Firstly, the Brazilian government has to loosen Petrobras' monopoly as a pre-salt operator. This change of law is expected to happen shortly as the senate has already passed it and only needs to be approved by congress. This change will allow for greater involvement and operatorship by international oil companies in the huge pre-salt opportunities.

Secondly, the government has to confirm the continuation of current tax reliefs for the offshore development also called "Repetro." This is a crucial tax relief on investments that could in itself be a show stopper for new investments in the sector.

Thirdly, the government is required to show more flexibility regarding the decisions on either PSA or normal concessions in the pre-salt area. Today, the law states that there should be PSA in all new pre-salt auctions, something that might complicate proceedings significantly when adding acreage to existing discoveries (the upcoming Unitization Round). A unitization process is implemented to simplify coordination between different consortiums or companies realizing that they have rights to the same reservoir. By awarding new area in an existing discovery with a completely different regulation will not simplify

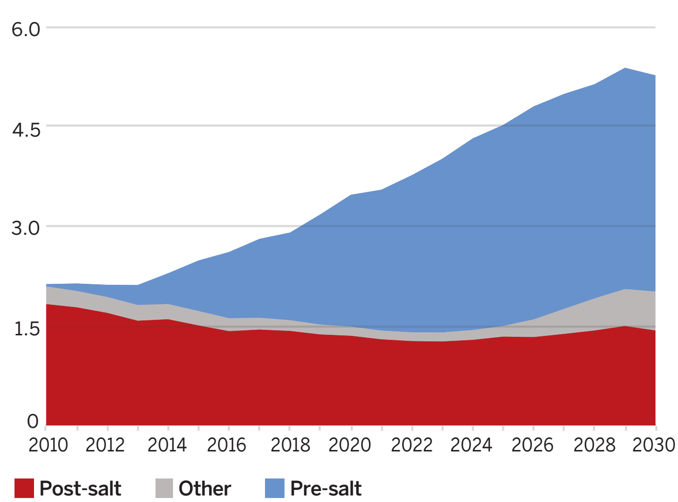
Outlook for Atlantic margin exploration wildcat wells



Source: Rystad Energy ECube

Figure 1: Exploration wells along the Atlantic margin in Brazil.

Brazil long-term production outlook (MMb/d oil and NGLs)



Source: Rystad Energy UCube

Figure 2: Brazil long-term production outlook.

but significantly complicate a coordinated and cost efficient development of a common reservoir.

Lastly, Brazil requires a more realistic and functional local content policy. It is only fair to expect that an increasing share of the supplies for offshore developments can be and should be constructed in Brazil. However, this has to happen over time through strengthening of the local industry and building sustainable competitive suppliers. How to fix the transition to a new regime for local content is a very delicate matter; however, it is crucial in order to get new projects developed.

There are good reasons to expect progress on all these matters, however, we assume that companies will only feel more comfortable when the new government is confirmed to continue. The final vote on impeachment of President Dilma Rousseff is expected to be taking place by the end of August (as *OE* went to press). It is expected that Michel Temer's, current interim president, administration will implement significant changes in oil and gas policies and try to solve the challenges mentioned above.

For Exxon, the Liza project is expected to move forward more smoothly. The current industry in Guyana is fairly limited; the economy is small, and the expectations for local content seems to be more realistic. For the Brazilian industry, a project like Liza should be seen as an opportunity to take advantage of the proximity to Guyana's waters and to show international competitiveness. A successful local industry in Brazil should have exports of products and services as a clear ambition. Both the markets to the northwest of Brazil and in southern Africa should be strategically ideal for the offshore industry working out of Brazil.

If we look at the numbers of floating production, storage and offloading vessels (FPSOs), Brazil (including pre-salt), Guyana, and Southern Africa will demand 40-60 FPSOs over the next 10 years. Subsea systems and over 100 deepwater wells expected to be drilled will certainly assure a huge interest on the offshore market in Brazil.

If we look closer into the pre-salt fields in Brazil, we see several fields with more than 1 billion bbl in reserves, and this is before we have taken into consideration the volumes in the reservoirs, which are still in open acreage.

The fields predominantly show a breakeven oil price (10% IRR) between \$40-80/bbl, with Lula at \$40 and Carcará in the top range between \$55-70/boe. There is certainly significant upside potential to the numbers in Carcará linked to getting increased recovery of reserves out of the field and also to evaluate a more efficient development with lower costs per barrel. An efficient development of the pre-salt also depends on the policies of the government.

A last very important issue for Carcará is the "Unitization Round." It is assumed that as much as 30-50% of the whole Carcará structure could be in open acreage and that this will be unitized with the existing Carcará license. This will make the development of Carcará even more robust, and would reduce the breakeven oil price even further. This could become a better investment opportunity than the giant Libra field.

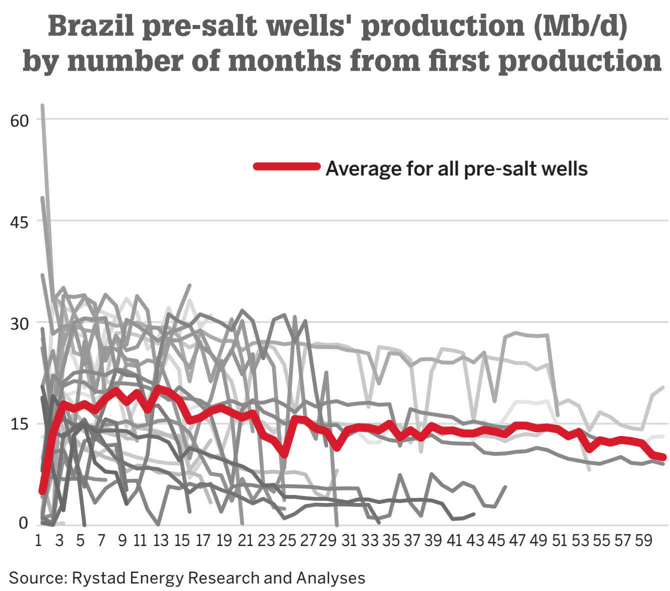


Figure 3: Oil production from pre-salt wells in terms of number of months from start of production

The key strength of the pre-salt fields is the extremely high productivity in the wells as shown in Figure 2. Having wells producing up to 50,000 b/d with low decline rates is unique in the world of oil fields. By getting more diversity of operators one should expect a positive development on learning curves for drilling wells, and executing on project development. Brazil's production is expected to increase to above 3 MMb/d within three years. The pre-salt is expected to be half of this volume and will continue to increase going forward. Given a successful oil and gas policy, Brazil could produce around 5 MMb/d within 10 years from now, placing it among the seven largest producers in the world.

The Liza field has a breakeven cost in the low range compared to the pre-salt fields in Brazil, and is expected to be sanctioned in 2017. The field is the first to be developed on the Atlantic margin and Exxon's plans to develop the field is a strong proof of feasibility of developing deepwater fields outside South America. Maybe Liza will become a good and very relevant benchmark for the many developments in the pre-salt region in Brazil, and for the cost of developing a giant deepwater field in South America with very limited local content requirements.

The potential in South America is huge and with the Exxon discovery and Statoil's acquisition it seems activity again is about to return to the continent. **OE**

Kjetil Sobraekke *is senior vice president for South America at Rystad Energy, and he heads the firm's Rio de Janeiro office. Sobraekke has more than 25 years of oil and gas experience in both Europe and South America. Since 2005, Sobraekke has lived in Brazil, where he previously served as CEO for Panoro Energy, and general manager for Norsk Hydro.*

Brazil Offshore

Rio games

Left: The Olympics logo with Brazil's Christ the Redeemer statue in the background.

Below: International Olympic Committee President Thomas Bach participates in the Olympic Torch Relay in Rio de Janeiro before the opening ceremony of the Rio 2016 Olympic Games.
Photos by Ian Jones/IOC.

Brazil has been a global leader in deepwater technology. If it can put its troubles behind, it has a real opportunity to be the world leader, says io oil & gas' Ed Hernandez.

As host of the Rio 2016 Olympic and Paralympic Games last month, the world's eyes have been turned to Brazil this summer. Yet, there were clouds on the horizon.

Only weeks before the games, the price tag for the Rio 2016 Olympic and Paralympic Games had risen by 400 million reais (US$124 million) since August 2015, primarily due to rising costs of supplying temporary power and seating at venues. The projected total cost for the games, including large and troubled infrastructure projects like an extended subway and reformed port area, now stands at 39.1 billion reais ($12.1 billion).

For many observers, this is a story of Brazil's obvious potential being compromised by its over-reaching leaders. Such a tale will be familiar to those in the oil and gas industry, who will associate Brazil with its embattled President Dilma Rouseff and the issues currently facing Brazil's national oil company, Petrobras. Yet, beyond the headlines, changes are afoot that suggest the future for Brazil might be very bright indeed.

Promisingly, after many years of relative isolation, Brazil is finally taking steps to open its oil and gas sector, making it more attractive to foreign investors. Driven by the country's new Energy Minister Eduardo Braga, reforms are being put in place to allow foreign oil and gas firms to access Brazil's major offshore oil deposits without needing to work in partnership with Petrobras (as is currently the case).

Indeed, in July, Statoil made the most of this opportunity and paid $2.5 billion for a substantial part of the Carcará oil discovery in the Santos Basin, one of the largest discoveries in the world in recent years.

While some of the reforms being implemented might be controversial in the eyes of Brazilian nationals, these measures could allow the country to finally benefit from its long underexploited assets.

The fact remains that, despite the current corruption scandals and the low global oil prices, Brazil has led the way in the region with respect to research and development, policy creation and exploration campaigns in deep and ultra-deepwater.

Brazil's pre-salt offshore contains an estimated 56 billion bo, but also presents a significant technical challenge. There are difficulties around ultra-deepwater, deep carbonate reservoirs, the high gas-oil ratio of areas, CO_2 content, high-pressure and low-temperature, thick salt layers (more than 2000m in places) as well as long distances from the coast and often turbulent oceanic conditions. The specific geology of the area also means that petroleum is extremely hot, which can cause precipitation in extraction lines that are in contact with sea water.

However, such difficulties are not insurmountable, and there are significant returns to be made for operators who can meet these technical challenges. By liberalizing Brazil's oil and gas industry, the country's government has made it more attractive for IOCs (independent oil companies) to commit research and development resources to the province, accelerating the rate at which these technical problems can be solved.

Importantly, recent discoveries in shallow waters have also surprised the market with estimates reaching 3 billion bo in a single well. The new big discoveries in this region could make Brazil the sixth largest oil and gas producer in the world in future years.

Ever since Stefan Zweig, writing in 1941, dubbed it "the land of the future," Brazil has been reproached for failing to live up to the promise that its size, its resources and its insulation from the wars and troubles afflicting other parts of the world seemed to hold out. However, when it comes to oil and gas, putting recent scandals behind itself, and embracing innovative ways of working and thinking, particularly in ultra-deepwater, Brazil has a real opportunity to be the world leader many hoped it would become. OE

Ed Hernandez is vice president of operations – Americas, for io oil & gas consulting, where he is responsible for business development in Latin America. He has more than 20 years' experience in the energy industry, working on numerous international and domestic projects from oil and gas production and pipelines to power generation. Hernandez holds a BS in mechanical engineering from Texas A&M University.

Brazilian uptick

A number of key contracts were awarded in 1H 2016 in Brazil, pointing to a recovery of the local oil and gas sector.

The *Polvo* FPSO (right) while docked at Keppel FELS shipyard. Photo from Keppel.

At the time of writing, the winning bidder for the charter contract of the Libra (pilot project) and Sépia floating production, storage and offloading (FPSO) units had yet to be announced.

In July, Petrobras received proposals from SBM Offshore, Modec, BW Offshore and the Bluewater and Queiroz Galvão consortium, but it was later revealed that only Modec qualified for the two contracts. Local industry sources speculate that a re-bid is likely to take place.

In late June, Wood Group was awarded a "multi-million dollar" contract to provide detailed engineering and procurement services to Statoil for the development of the WHP-C wellhead platform. The work will be performed for US-based Kiewit Offshore Services, which will build the platform's deck. WHP-C will be the third wellhead platform at the Peregrino heavy field in the Campos basin and its construction is part of the field's second development phase.

Subsea

In April, Aker Solutions was awarded a three-year US$134 million contract by Petrobras covering the maintenance, storage, parts supply and technical assistance for all the equipment delivered to the oil company in Brazil. Aker's subsea services unit in Rio das Ostras will be responsible for the contract, which will meet an 87% local content requirement.

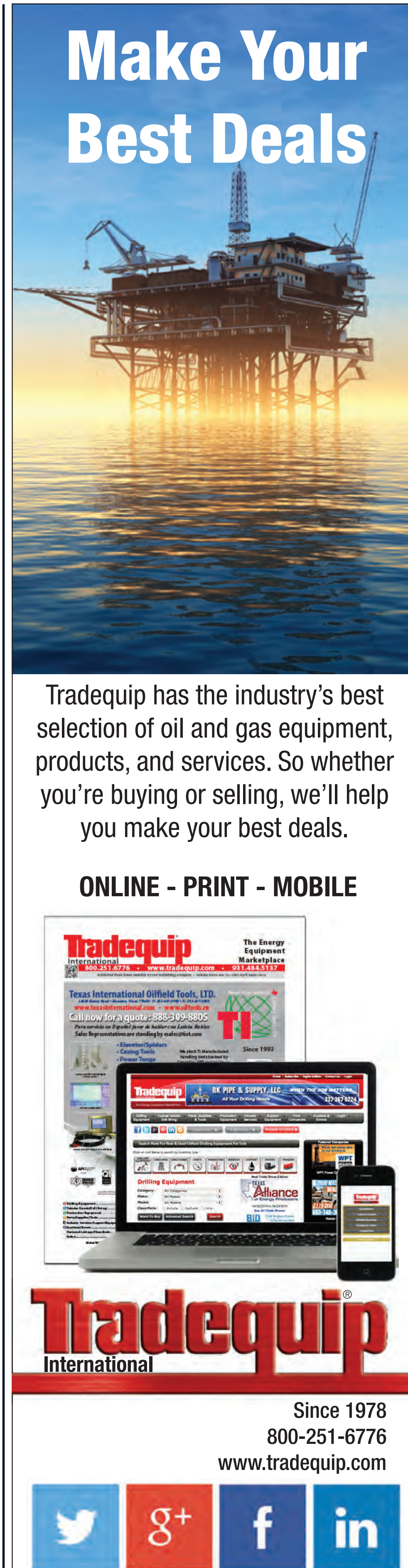
Operations and maintenance

In early January, Wood Group PSN was awarded a two-year contract by PetroRio, a local oil company, to provide operation and maintenance services for the Polvo A fixed platform at field of the same name in the Campos Basin. In addition to this platform, the field also features the FPSO *Polvo*, owned by BW Offshore. The FPSO specialist obtained a two-year extension of its lease and operation contract with PetroRio in December 2015.

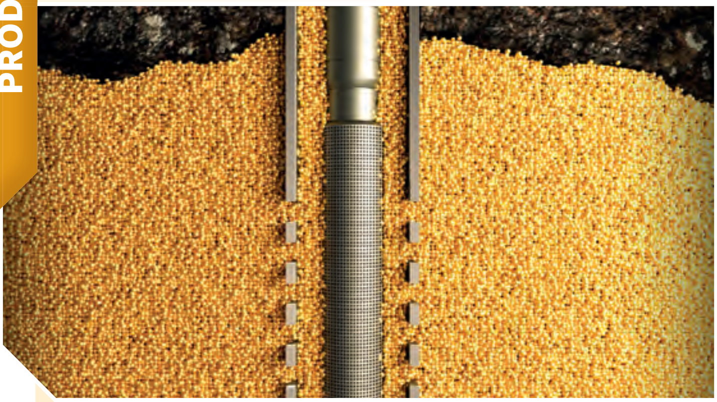
Market perspectives

The acquisition of a 66% operated interest in the Carcará pre-salt field by Statoil announced in July was welcomed by the local supply chain, which also met with great enthusiasm plans by Karoon to install an FPSO in the Santos basin by 2019. Meanwhile, the release of Petrobras' 2016-2020 business plan, due in October, is highly anticipated.

*A graduate in International Relations, **Pietro Ferreira** works as a Regional Analyst at the Energy Industries Council (EIC) regional office in Rio de Janeiro, Brazil.*



Solutions



CARBO develops FUSION

CARBO has introduced FUSION, a proppant pack consolidation technology for deepwater injection and production wells, which is designed to create a bonded proppant pack with or without closure stress.

FUSION technology has been developed to allow increased injection and production rates in deepwater fields, enabling pressure maintenance and increased ultimate recovery and ROI (return on investment). FUSION aims to improve well productivity by enabling operators to create a high-integrity, high-permeability annular pack in the low compressive strength environment of the annulus that retains its integrity under high water injection rates.

The technology features durable, ultra-high conductivity ceramic proppant with a proprietary resin coating, which enables controlled bonding of the proppant pack by using a unique chemical-activator. The chemical-activated bonding process forms a strong, flexible bond without compression, even in low temperature environments, to create a high integrity pack meant to withstand stress cycling to sustain long-term proppant pack integrity.

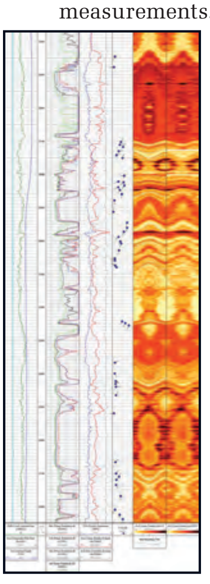
Permanently detectable CARBONRT inert tracer technology is manufactured into the substrate of every proppant grain, enabling proppant in the annulus to be detected (with a standard neutron logging tool) to evaluate pack placement and quality at any time during the life of the well. www.carboceramics.com

Halliburton launches LWD density service

Sperry Drilling, a Halliburton business, introduced the 9.5in Azimuthal Lithodensity (ALD) service, providing real-time density measurements and images in boreholes up to 17.5in.

ALD is designed to provide downhole density measurements, including high-quality borehole image logs, to help optimize wellbore placement through geosteering and to reduce geological uncertainties. The measurements, delivered via LWD (logging-while-drilling), can eliminate wireline conveyance runs and capture data immediately after drilling when the borehole is in the best condition.

The 9.5in ALD provides the same functionality as its smaller counterparts, including azimuthal density, and photoelectric and acoustic stand-off measurements. This information has a wide range of applications that can help determine a formation's porosity, rock strength, pore pressure and borehole geometry.



In the Gulf of Mexico, as an alternative to wireline runs, an operator used the density measurement to identify shallow hydrocarbon deposits in a 17.5-in borehole. In another case, an operator used borehole density images in real-time to determine the formation dip and reservoir structure immediately below a massive salt interval in a 16.5in borehole, where surface seismic data was poor. www.halliburton.com

James Fisher unveils excavation tool

James Fisher Subsea Excavation, part of James Fisher and Sons, has brought the SP12000 mass flow excavation (MFE) tool to market to support clients with large scale excavations.

The SP12000 produces more than 6-tonne of thrust at full power and a volume output of 12,000 L/sec (3170 gal/sec) of water, which can be used for large seabed preparation projects, sandwave clearances, freespan rectifications and large diameter pipeline trenching.

James Fisher Subsea Excavation's team completed an extensive re-engineering project on the SP12000. Advanced hydrodynamics and improved efficiency have been combined to improve the flow regime for a mass or controlled flow excavator to cut trench. Despite its size, the fully-controllable SP12000 is also capable of smaller-scale, precision excavation. www.jfsubseaexcavation.com

Damen eyes decommissioning

Dutch firm Damen Shipyards Group's latest concept design, the Damen Decommissioning Series, will specialize in three core areas for oil and gas decommissioning: topside decommissioning, offshore platform removal, and subsea cleaning and removal.

A monohull vessel designed with a split stern will be used for platform removal operations.

"This ship will be able to reverse up to a jacket, where it will be ballasted to sink below the platform. Upon deballasting, the vessel will rise up to pick up the platform," said Justin Rietveld, who carried out the in-house research at Damen.

Preliminary estimates show the vessel will be capable of decommissioning fixed platforms up to 1600-tonne, covering over half of the fixed platforms in the North Sea, says Damen.

The concept design includes modular add-ons, including a (temporary) crane or helideck installation, opening markets outside of decommissioning. Functionality can be boosted with the addition of accommodation modules to increase personnel capacity. Another option will be the addition of a temporary platform to create a solid stern, increasing the deck capacity, allowing monopiles and foundations to be transported and installed for the offshore wind industry.

www.damen.com

Gastech

Conference & Exhibition

4-7 APRIL 2017

Makuhari Messe Chiba,
Tokyo, Japan

Hosted by: Japan Gastech Consortium

Diamond Sponsor:

80% exhibition space sold

EXHIBIT AT THE WORLD'S LARGEST GAS EVENT

Gastech is geared to energy professionals who are operating on a technical and strategic level across the global gas and LNG sector. By exhibiting at Gastech 2017, you will be part of the world's largest and most influential gathering in the natural gas and LNG industry.

54,000+ Square Metres Exhibition Space

25,000+ International Attendees

2,500 Commercial and Technical Delegates

750+ Hosted Meetings

600+ Regional and International Exhibitors

350+ CEOs, Government & Ministers

200+ Speakers from Leading Energy Specialists and Companies

70+ Countries representing the global gas production, supply, service & technology value chain

30 New Technical Conference Sessions

14 International Country Pavilions

4 Days packed with high quality Commercial Conference content

Who exhibits?

Exhibiting companies represent the following sectors:
IOCs, NOCs, EPCs & FEEDs, Shipbuilders, Marine Engineering, Gas Processing and LNG Technology & Service Providers.

To discuss your participation please email sales@gastechevent.com or call

LONDON
Damian Howard
T: +44 (0) 203 772 6038

JAPAN
Atsuhiro Furuya (Tony)
T: +81 (3) 6890 0783

SINGAPORE
Shunker Goel
T: +65 6422 1489

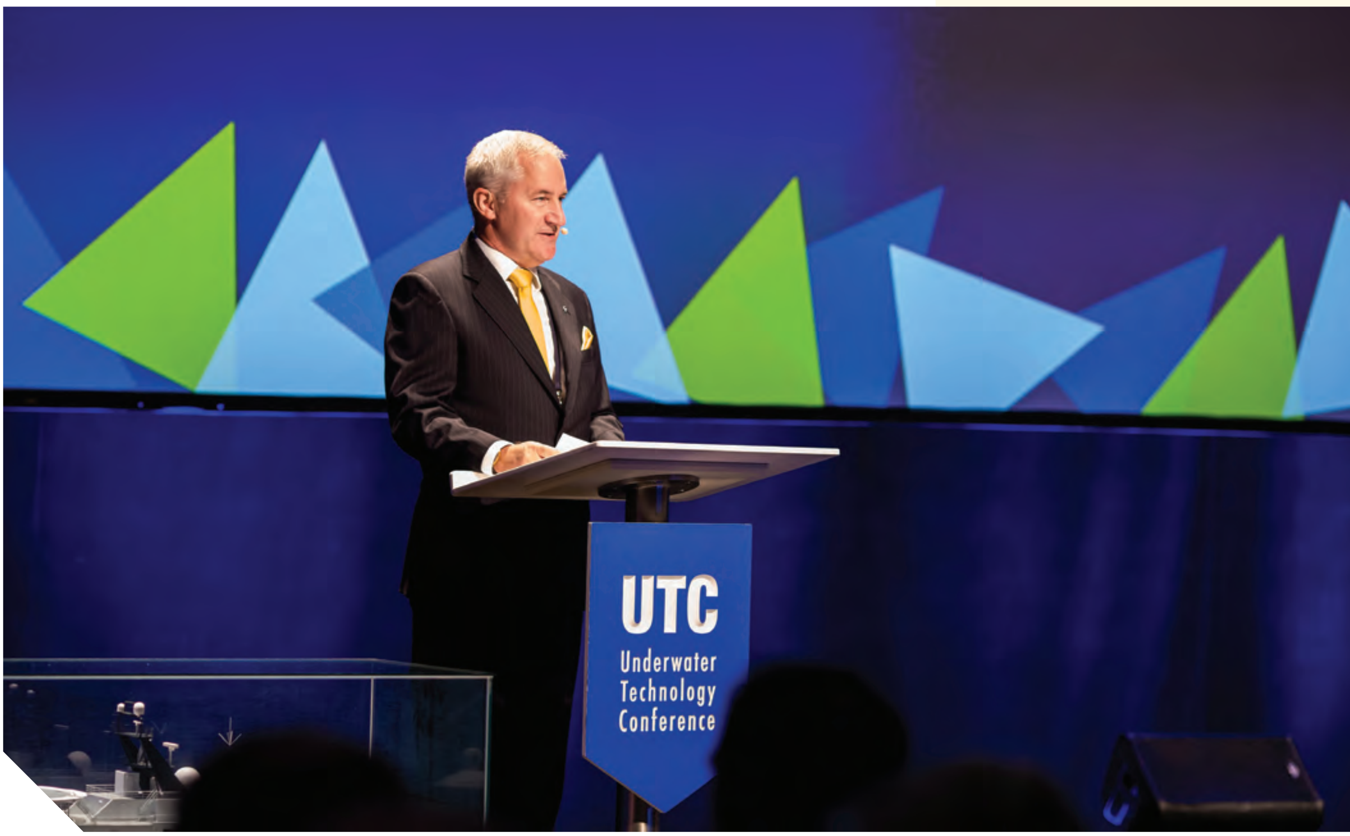
www.gastechevent.com/oe1

Organised by: dmg::events global energy

Spotlight

Collaboration, Bach and subsea processing

Elaine Maslin profiles Statoil's project manager technology development and UTC conference moderator Simon Davies.



Simon Davies. Photo from Statoil.

Over the past three years, Simon Davies has been the genial and reflective moderator of the annual Underwater Technology Conference in Bergen leading us through from the agonies of the end of a sustained period of growth and cost escalations through to today's focus on lean.

He's also part of a Norwegian choir, singing the music of J.S. Bach in Norway and overseas (earlier this year they performed in Vilnius, Lithuania).

But, he's also known for his time at Kvaerner and Statoil, where, at the latter, one of his achievements was to help initiate the process to unlock a tranche of marginal fields through the creation of Statoil's successful Fast-Track subsea tieback program.

Fast-Track cut the normal development time for small subsea tiebacks in half from about five years to just 2.5, using simplified standardized equipment. Some 11 fields were targeted, containing around 700 MMboe, with 10 of those already in production, and the last field expected to come on stream in Q3 2016.

> "Technology is about collaboration. Much of our focus at the moment is to use technologies that help us save time and money..."

Davies wasn't at Statoil long before he was thrown in the deep end with this project in late 2009. "I was someone new in the organization and didn't know how things were being done and it meant I was able to bring in new thinking and challenge the team members selected to develop the Fast-Track principles," he says. The key was a group of marginal discoveries that were not meeting investment hurdles on their own – as a portfolio, Davies says. "If you could treat them as a portfolio of standardized subsea tieback solutions, you could reduce the time it took to develop them and reduce the cost as well."

It was an aggressive program. Even the process to formulate this idea was quick– just six weeks working day and night.

Subsea processing technologies, collaboration, networking and bringing people together, but always with a commercial eye, have been themes throughout Davies' career – and maybe not quite the outcome he would have had if he'd taken his initial career choice as a weapons engineer in the Royal Navy.

Davies was born in Gibraltar and brought up in Malta in a military family: his father was in the Royal Fleet Auxiliary. After being steered away from a career in the forces, he went for a degree in chemical engineering at Heriot-Watt University in Edinburgh.

Heriot-Watt is well-connected within the industry and had an Institute of Offshore Engineering, where Davies first worked upon graduation. This job resulted in numerous connections with the Norwegian industry, but also in Davies helping to set up a water treatment and test facility for Conoco next to Occidental's Flotta terminal, Orkney. Water treatment was a hot topic at the time, so the project also spawned various joint industry projects.

The job saw Davies living in Kirkwall, on the Orkney mainland and commuting to work by boat.

But, in 1993, after meeting his future wife, a Norwegian, he moved to Norway, and not long after, he joined Kvaerner Process Systems Group, overseeing technology development. "I was very lucky there," he says. "When Aker Solutions and Kvaerner converged, I ended up coordinating technology across those two." When Davies joined Kvaerner, the seeds of subsea separation and boosting were being sewn. It was an early contact with subsea processing that has kept Davies interested in the field ever since.

At Aker Kvaerner, Davies helped connect the dots, running the technology network within the organization, looking after license agreements, lifting the focus on IP and trademarks.

The next stop was Norsk Hydro, joining a research center in Porsgrunn, Norway, looking at a range of technologies, culminating in manager for Arctic technologies. However, when Hydro merged with Statoil, the Arctic team was split-up and Davies moved to Shell Technology in Oslo.

But, it wasn't long before Davies was back at Statoil, joining in 2009 as a project leader in the subsea and marine technology organization. He currently works as a project manager in the technology efficiency organization.

For Davies, it's all about new ideas and working with others. "Technology is about collaboration. Much of our focus at the moment is to use technologies that help us save time and money in Statoil, but it is also important for the suppliers that we work with to have their investment turned into income."

Technology development and implementation can take time. "We have to stay focused on technology development, but we also have to work on the business case for it," Davies says. "A good business case means that it is worth managing the risk of deploying something different that hasn't been tried before." OE

Activity

Intertek invests in center of excellence

Intertek invested a further US$1.04 million (£800,000) in its Manchester, UK, corrosion and materials center, renamed The Manchester Technology Centre for research, consulting and testing services.

This latest investment has enabled Intertek's Production and Integrity Assurance (P&IA) to integrate its specialist consultancy, corrosion management, infrastructure, asset integrity and production chemistry facilities into one purpose-built center of excellence, to answer increasing demand for these services worldwide.

"Investing in The Manchester Technology Centre will enhance our failure investigation, materials evaluation and testing capabilities," said Gareth John, director of consulting services, Intertek P&IA. "This state of the art facility also places Intertek in an ideal position to conduct specialist investigations, including innovative research and development programs."

Last year, P&IA invested $1.56 million (£1.2 million) into the center and expanded the site to 40,000sq ft. ▪

Subsea 7 acquires Swagelining

Subsea 7 moved to acquire polymer lining technology firm Swagelining in August. The two firms have already cooperated together, designing and installing in excess of 150km of reeled and bundled polyethylene (PE) lined water injection flowlines in the North Sea, for a number of operators and developments. Swagelining employs about 50 people and occupies leased space at North Clydesdale Industrial Park, Glasgow. "The acquisition of Swagelining will enable Subsea 7 to enhance its flowline and riser technology portfolios, and supports Subsea 7's commitment to develop and apply technologies that reduce cost, enhance production and extend field life," said Thomas Sunde, Subsea 7 VP Technology.

Solstad, REM agree to merger

Norwegian offshore support vessel firms Solstad Offshore and REM Offshore have agreed to combine. The united company will operate a combined fleet of 62 vessels.

After the merger, Solstad will retain its Skudeneshavn head office, from which the combined fleet of construction support vessels will be operated.

The combined fleet of platform supply vessels will be operated from the current REM head office in Fosnavåg.

"Solstad and REM both see the need to create larger entities with financial and operational strength to weather the downturn," says Lars Peder Solstad, CEO of Solstad, of the merger plans. "The combination of Solstad and REM is one step in the right direction, but there remains a strong rationale for further consolidation."

Van Oord adds wind farm expertise

Van Oord, a dredging, marine engineering and offshore projects contractor, will acquire the offshore wind activities of Bilfinger Marine & Offshore Systems, a German company active in the engineering, construction and installation of foundations for offshore wind parks and harbor construction.

The agreement covers the acquisition of assets and employees related to the offshore wind activities.

Van Oord will also replace the crane on the *Aeolus* installation vessel with a crane with a lifting capacity of 1600-tonne and extend the transport capacity. This will enable Van Oord to continue to install the increasingly larger foundations and heavier turbines at wind farms. Modification to the *Aeolus* will be completed in early 2018.

Forum opens Houston Syntech plant

Forum Energy Technologies (FET) has opened a new plant outside Houston expanding its syntactic foam manufacturing capabilities.

The six-acre facility in Bryan, Texas, brings Forum's Syntech product line closer to clients in the oil and gas industry and has the capacity to support future growth.

Syntech is used to provide buoyancy modules for use in remotely operated vehicles (ROVs) and other submersible equipment. The new plant not only allows the expansion of Forum's ROV flotation manufacturing capabilities, but also includes the expansion into manufacturing larger installation buoyancy modules, rigging buoyancy and custom/project specific flotation modules. Syntech will share the property with another of Forum's brands, Dynacon.

James Fisher buys Lexmar, HSSE

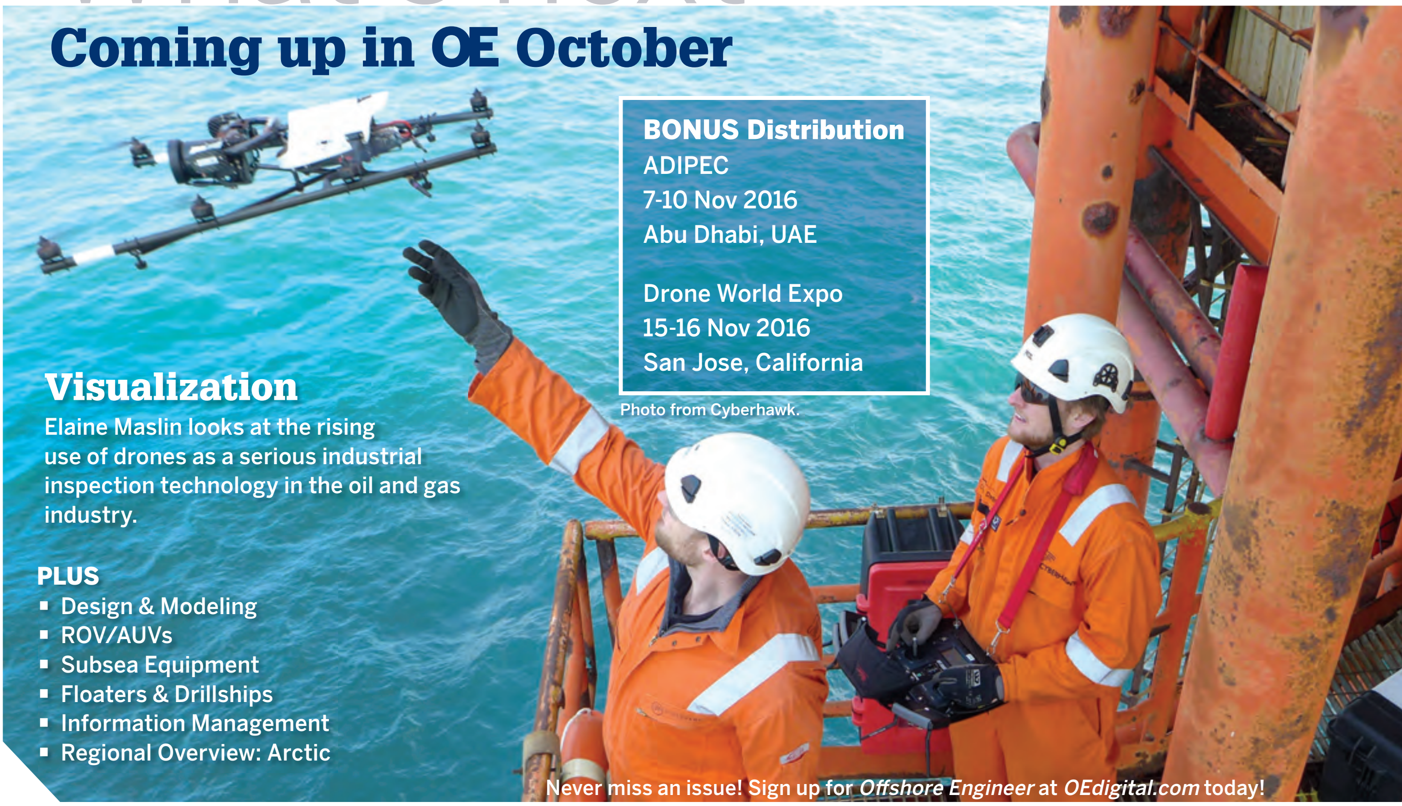
August was a busy month for UK-based marine specialists James Fisher & Sons. The group moved to acquired Singapore-based Lexmar Sat Systems and England-based Hughes Sub Surface Engineering. The US$20 million Lexmar acquisition is thought to strengthen James Fisher's specialist diving equipment services, and will be strategic due to its placement in the Asia Pacific region.

Bootle, England-based Hughes Sub Surface Engineering is a specialist diving, subsea and marine project company. James Fisher expects the acquisition to further enhance existing subsea activities and, through the combination of complementary capabilities, create a comprehensive portfolio of services focused in the oil and gas, marine renewables, power generation and marine civil engineering sectors. ▪

Editorial Index

What's next

Coming up in OE October



BONUS Distribution
ADIPEC
7-10 Nov 2016
Abu Dhabi, UAE

Drone World Expo
15-16 Nov 2016
San Jose, California

Photo from Cyberhawk.

Visualization

Elaine Maslin looks at the rising use of drones as a serious industrial inspection technology in the oil and gas industry.

PLUS
- Design & Modeling
- ROV/AUVs
- Subsea Equipment
- Floaters & Drillships
- Information Management
- Regional Overview: Arctic

Never miss an issue! Sign up for *Offshore Engineer* at *OEdigital.com* today!

Ad Index

OE

Advertising sales

NORTH AMERICA
Amy Vallance
Phone: +1 281-758-5733
avallance@atcomedia.com

UNITED KINGDOM SCANDINAVIA, GERMANY AND AUSTRIA
Brenda Homewood, Alad Ltd
Phone: +44 01732 459683
Fax: +44 01732 455837
brenda@aladltd.co.uk

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

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

FRANCE/SPAIN
Paul Thornhill, Alad Ltd
Phone: +44 01732 459683
paul@aladltd.co.uk

ASIA PACIFIC
June Jonet
Tel: +65 8112 6844
Email: junejonet@thesilverback.com


ONSHORE. OFFSHORE. EVERY SHORE.
IT ALL STARTS WITH API.™
No matter where you go around the world, the oil and natural gas industry relies on API Certification, API Training, API Events, API Standards, API Statistics, and API Safety. Show the world your commitment to quality. Start with API.
energy API®
It's times like these you need people like us.®
See us at Rio Oil & Gas 2016, booth R34a.
877.562.5187 (Toll-free U.S. & Canada) | +1.202.682.8041 (Local & International) | sales@api.org | www.api.org
© 2016 – API, all rights reserved. API, the API logo and the "It All Starts with API" tagline are trademarks or registered trademarks of API in the United States and/or other countries.

© 2015 National Oilwell Varco | All Rights Reserved