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The well intervention issue

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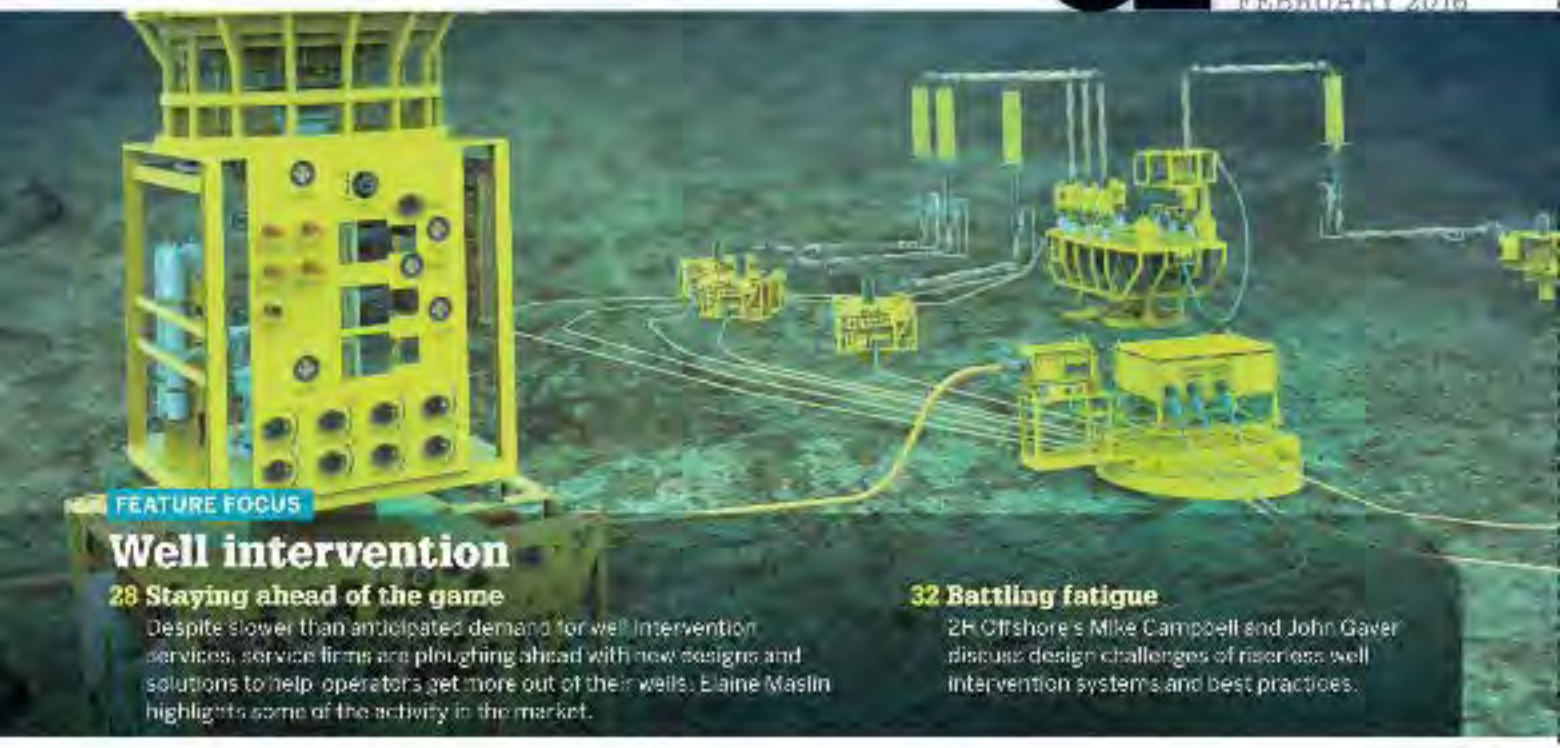

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ON THE COVER

Hardworking. This month's cover depicts a completion workover riser system (CWOR) from GE Oil & Gas, a riser player in the well access and intervention market. GE is one of the firms *OE* spoke with in February's special report on well intervention. See pages 28-35 for more. *Image from GE Oil & Gas.*

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Online Exclusive

Boosting efficiency in the UK North Sea

Falling production efficiency has recently become a thorn in the side of the UK North Sea oil and gas industry. Is the industry getting to grips with its efficiency issues and, some ask, is it really that bad? Elaine Maslin reports.

What's Trending

Unhappy New Year

- Norwegian investment continues to fall
- BP to cut 4000 jobs by 2017
- WoodMac: US$380 billion of projects on hold

Image from Vantage Drilling

Activity

Petrobras cuts capex

Petrobras has made deeper cuts to its five-year business plan in mid-January, cutting planned capital expenses by US$32 billion from the previously announced $130.3 billion it listed last June. Petrobras will put $80 billion (or 81%) of its capex toward exploration and production activities. Petrobras said that the revision keeps Brazilian E&P projects a priority, with an emphasis on pre-salt.

People

Amec CEO resigns

Amec Foster Wheeler's outspoken CEO Samir Brikho stepped down in January.

Ian McHoul, the firm's CFO, has been appointed interim CEO and will chair the group leadership team while the search for the new CEO is conducted.

The company cut its dividend by half in November as it attempts to survive a slump in oil prices — which are now below US$30/bbl.

Brikho, who has led Amec since 2006, oversaw the company's $3 billion acquisition of Swiss engineering group Foster Wheeler in 2014, when oil prices were more than $100/bbl.

On his departure from Amec, Brikho said: "It has been a privilege to lead Amec Foster Wheeler at a time of huge change in the global energy and commodities market. My aim has always been to help to create a leading integrated global service company capable of meeting our customer demands. I am so appreciative of the unstinting work and support of the 40,000 colleagues who all contribute to Amec Foster Wheeler's success."

Undercurrents

What's the deal?

2015 was the slowest year in a decade for merger and acquisition (M&A) activity. That may be somewhat surprising considering in Q1 2015 financial analysts were saying 2015 would be the year of the "mega merger."

"We've seen two blockbuster deals with Halliburton and Schlumberger," said William Stevens, global co-head of the SES/G Group of HSBC Bank, at a CERAWeek panel in Houston back in April 2015. "This might be the return of the big deals."

"A lot of companies are going to be sellers in order to survive," says Mike Bengtson, an attorney with Baker Botts. "If they are not drilling, the production rates are coming down. Cash flow from the hedges is coming down. All the factors that kept them artificially alive, or on the pause button last year, are reversing."

Yet, IHS reported that the total transaction value for global upstream oil and gas M&A deals in 2015 declined 22% to US$143 billion, down from $184 billion in 2014. Wood Mackenzie noted that the average monthly deal count fell by over a third, compared with the preceding 24 months; deal spend collapsed by two-thirds further. It said only 14 deals higher than a billion dollars in value were announced, compared with 46 in 2014.

There were some notable mergers: the $70 billion Shell and BG Group merger, announced last April and still yet to complete, and the $14.8 billion pairing of Schlumberger and Cameron. But, as the price continued to plummet, the resolve to merge also fell.

Several large, unsolicited corporate takeover bids were rejected and asset deal value fell to a 10-year low, according to IHS. These included Houston-based Independent Anadarko's bid for fellow Houston firm Apache and Australian operator Woodside's $8 billion offer for Papua New Guinea-focused Oil Search.

What's the deal? Both IHS and Wood Mackenzie have attributed the M&A slowdown to oil price volatility, which IHS says made it hard for both buyers and sellers to agree on value and outlook.

"There was a big disconnect between buyers and sellers on future price expectations," says Mike Bengtson, an attorney with Baker Botts, who handles M&A. "No one knew how long the price declines would last, and people thought there would be a rebound. As a result, there were a lot of failed sales processes. Properties were taken off the market. No one wanted to be the one who sold at the bottom."

Bengtson expects activity to increase in 2016, with some companies that avoided bankruptcy not able to stave it off this year. "A lot of companies are going to be sellers in order to survive," he says. "If they are not drilling, the production rates are coming down. Cash flow from the hedges is coming down. All the factors that kept them artificially alive, or on the pause button last year, are reversing.

"There's more clarity – people thought this was temporary, but that's not the case," he continues. "We're one year further down the road. Some of the macro trends, Iranian production, the lifting of the US export ban, a lot of the macro trends have come into clearer focus."

So who is likely to be selling those days? Bengtson says what is important this year for companies is to control how capital is being spent. And the likely sellers will be those non-operators that cannot control when exploration or development decisions are made.

Additionally, he says M&A deals are going to be more complicated. "The debt financing that was used to be available, is not as available," Bengtson says. "Borrowing bases have tightened. Buyers are going to have to have available cash, liquidity, or access to the private capital markets." OE

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The Barrel

Fighting for survival

So much for a happy new year. The first few weeks of 2016 have given no cause for cheer with crude falling a further 20%, more job losses, and further project delays or cancellations.

It's been a horrible start to 2016. A record number of short contracts are weighing on the price of crude oil. Plus, the price has broken below the US$30 threshold and $20 a barrel now looks like a very real prospect.

Obviously this is terrible news for the upstream industry and it is going to be an incredibly tough year for everyone involved in or dependent upon oil and gas production. I firmly believe that only the fittest companies will survive.

"It is going to be an incredibly tough year for everyone involved in or dependent upon oil and gas. I firmly believe that only the fittest companies will survive."

Colin Welsh, CEO
Simmons & Company International Limited

It is extremely difficult to be positive in the face of such a torrential flow of bad news, but it's important to put things in perspective.

The declines in North American production are now accelerating and stockpiles there seem to have plateaued.

While Iranian sanctions have now been lifted, it will take some time to agree to contracts with oil companies and service providers in order to begin the work needed to rejuvenate production. So, fears of an overnight glut from there may be overblown.

Demand growth for crude oil in 2015 was 1.8 MMb/d, yet most forecasters are predicting a return to historic norms of just 1 MMb/d of growth in 2016. I struggle to see the logic for this given that low prices typically stimulate demand. Clearly, China is a big part of this. Again, many commentators refer to an impending reduction in the size of China's economy when in fact it's the rate of growth that is slowing and not the size of its overall economy.

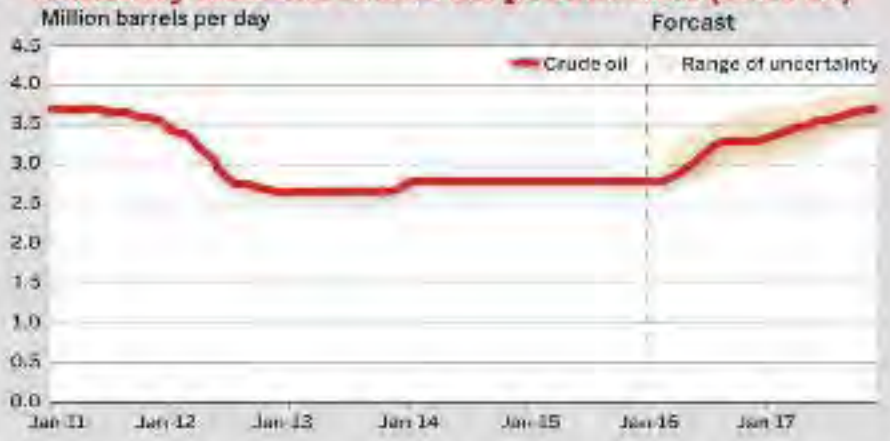
My final point of solace is that despite the recent slump in crude prices the five-year average price is $94/bbl. Markets have a habit of reverting to their long-term averages and $60/bbl – let alone the current price – is simply not economic for any of the major producers, so you have to hope for and expect a recovery before too long.

Unfortunately, it's impossible to predict when that will happen. As Warren Buffett said, "Some things just take time. You can't make a baby in a month by getting nine girls pregnant!"

In the meantime the industry mustn't panic and become locked in short-term thinking. Businesses and their investors need to keep calm, focus on survival and also look through the cycle. The system has suffered a shock but isn't broken and there will be a lot of opportunities ahead for the survivors.

The important thing to remember is that the industry will survive; this current period of difficulty to see many more days in the sun. OE

Monthly Iranian crude oil production (2011-17)



Source: US Energy Information Administration, Short-Term Energy Outlook, January 2016

Colin Welsh joined Simmons & Co. in 1998 to establish the firm's Eastern Hemisphere business. Prior to joining Simmons, in 1987, Welsh established the Aberdeen office of HMD, a newly-formed accountancy and corporate finance firm. Previously, he worked in both the London and Aberdeen offices of Touche Ross. Welsh graduated from Aberdeen University having studied economics, accountancy and law. He went on to qualify as a Scottish Chartered Accountant while working at Ernst & Whinney (now Ernst & Young).

Global E&P Briefs

A Mexico signs remaining PSCs

Pan American Energy and Fieldwood Energy have each signed production sharing contracts with Mexican officials for offshore areas awarded in the phase two bid round on 30 September. The round produced three winning bids for the five blocks offered in the shallow waters of the southeast basin. The third winner, Italy's Eni, signed their PSC back in November. Mexico's secretary of energy (SENER) estimates production could be begin by 2018 and reach a peak of 55,000 b/d. Planned investment is estimated at US$2 billion for the duration of the projects.

B Surveys ramp up off Campeche

Mexico's Pemex extended Fugro's contract to support its exploration drilling activities in the Bay of Campeche, which includes geophysical and geotechnical field operations, laboratory testing and geoconsulting activities. *Fugro Synergy*, an ultra-deepwater geotechnical and well services vessel, will be used for the field program, while the geoconsulting program will continue through 2016.

Additionally, Schlumberger and Statoil signed an agreement to license a large part of the WesternGeco Campeche wide-azimuth deepwater multiclient seismic survey in the southern Gulf of Mexico. The license also includes collaboration with WesternGeco in the seismic processing phase.

A fleet of eight vessels is conducting the survey in the Bay of Campeche for the three-year project. The project follows the Mexican government opening licensing rounds to non-government companies for the first time.

C Repsol requests Guyana extension

Repsol representatives met with Guyana's president David Granger to seek an extension to continue exploratory work in the Kanuku Block offshore the South American country. The company faced several setbacks, the government noted, including a legal dispute with CGX Energy that arose in 2012 over exploration activities in the Georgetown block. This dispute was resolved in 2014.

"We want a short extension in order to continue working in the block and eventually drill a well," said Mikel Erquiaga, Repsol's Latin America exploration director.

The Kanuku block is 50mi off Guyana, and covers an area of 6525sq km. Kanuku represents a high potential exploration opportunity with significant prospectivity mainly in Cretaceous strata in water depths ranging from shallow shelf to 200m, according to partner RWE DEA.

D Anadarko brings Heidelberg online

Anadarko Petroleum has achieved first oil at the Heidelberg spar development in Green Canyon 859 in the US Gulf of Mexico. Originally expected in April 2016, the milestone was achieved about three months ahead of schedule in mid-January.

The Heidelberg development consists of six production wells, two drill centers, dual looped 8in flowlines, 16in oil and gas export lines, and a standalone spar, a 80,000 b/d floating production facility. It was developed as part of a "design one, build two" strategy, being 87% identical to Anadarko's Lucius truss spar. Read more about the Heidelberg and Lucius projects on page 25.

E Premier hits in Isobel Deep

Premier Oil confirmed its Isobel Deep oil discovery offshore the Falklands, as well as an additional discovery in the same well.

The well reached 3014m total depth, hitting 27m of net pay, with no oil water contact or gas, confirming the main oil discovery and additional oil bearing F3 reservoirs.

According to Falkland Oil and Gas, the well, drilled using the *Eirik Raude* semisubmersible drilling rig, successfully penetrated five separate fans within the complex and discovered oil in the Isobel Deep, Isobel, and Emily fan systems.

Operations have now been suspended and the well will be plugged and abandoned as planned.

F Petrobras confirms Carcará Norte

Petrobras concluded two formation tests in the 3-SPS-103 (Carcará Norte) well, confirming the high productivity of the pre-salt carbonate reservoirs.

The results from the fluid

and pressure analyses in the formation tests and the tests conducted in the discovery well and the Carcará Noroeste well (3-SPS-104DA) indicate that it is a single oil accumulation.

The well is in the area of the Carcará Discovery Evaluation Plan (PAD), 4.6km north of the discovery well (4-SPS-86B), in water depth of 2070m and reached final depth of 6338m, inside basaltic rocks.

G Senegal well flows for Cairn

Cairn Energy has successfully tested its SNE-2 appraisal well offshore Senegal. The drill stem test was performed over a 12m interval of high-quality pay and flowed at a maximum stabilized, but constrained rate of ~8000 b/d on a 48/64in choke, confirming the high deliverability of the principal reservoir unit in the SNE-2 well. Initial indications confirm the same 32° API oil quality as seen in SNE-1, Cairn said. The SNE-2 well, drilled to 2800m total depth below sea level, is in 1200m water depth, and is about 100km offshore in the Sangomar Offshore block.

The well has been appraising the 2014 discovery of high quality oil in the SNE-1 well, some 3km to the south.

H Vitol dry off Ivory Coast

Vitol Energy is plugging and abandoning the Aigle-1X exploration well off the Ivory Coast after failing to encounter hydrocarbons, according to partner Genel Energy. The well is in Block CI-508, approximately 40km from San Pedro Western Côte d'Ivoire Basin. The block covers 1060sq km. Aigle-1x was being drilled to test the top-ranked prospect, Interino-Reed, around 4200m below sea level. The well was anticipated to target 300 MMbbl.

J PGS begins Namibia seismic

PGS Exploration began a 3D seismic acquisition survey of approximately 2600sq km in Blocks 2312 & 2412A (Central Blocks) offshore Namibia in mid-January on behalf of Chariot Oil & Gas.

Following the analysis of 2D seismic data acquired on the northwestern flank of the license in 2015, Chariot says it has identified several

I Eni begins Mpungi production

Eni has commenced production from the Mpungi field offshore Angola. Mpungi's startup, follows the West Hub's first oil from the Sangos field in November 2014 and the Cinguvu field in early April 2015. With Mpungi, production is expected to ramp up to approximately 100,000 bo/d in Q1 2016, Eni said.

Mpungi is located within Block 15/06 of the Angolan Deep Offshore, some 350km northwest of Luanda and 130km west of Soyo.

The West Hub Development Project encompasses the development of the Sangos, Cinguvu, Mpungi, Mpungi North, Ochigufu and Vandumbu fields in a water depth ranging from 1000-1500m. The wells are arranged in clusters and connected to the N'Goma FPSO (floating production storage and offloading unit), which has a treatment capacity of 100,000 boe/d.

significant additional leads within the Upper Cretaceous deep water clastic turbidite system.

The survey is expected to take 40 days.

More setbacks for Greater Stella

First production from the UK North Sea Greater Stella Area development has been set back once again. Sail-away of the FPF-1 floating production facility is expected to be delayed by six-12 weeks due to slippage in completion of certain commissioning milestones in the Remontowa shipyard in Poland, says operator Ithaca. Some marine system re-work was also needed to ensure the vessel meets the required sail-away certification standards, said the firm. The result is the first production is now anticipated in Q3 2016.

First gas at Corrib

Shell started first natural gas production from the Corrib field, 83km off Ireland's northwest coast in nearly 350m water depth. At peak annual production, Corrib is expected to produce about 260 MMscf/d of gas, which is 45,000 boe/d. The Corrib field has been developed as a subsea-to-shore tieback solution, and can potentially meet up to 60% of Ireland's gas needs at peak production, according to Shell.

Norwegian licensing round hailed a success

Norway's latest awards in predefined areas (APA) round has been hailed a success with some 56 exploration licenses offered on the Norwegian Continental Shelf.

The APA rounds offered acreage in known areas on the shelf, rather than frontier.

The 56 licenses are split across the North Sea (27), Norwegian Sea (24) and Barents Sea (5). The round involves 36 different oil companies, from international majors to small Norwegian exploration outfits, of which 22 will be offered one or more

Contracts

IKM lands Johan Castberg deal

Statoil awarded IKM Ocean Design a contract for the Johan Castberg subsea project.

The scope of work includes pre-FEED and FEED of pipelines, risers, cables, tie-ins and related structures. Furthermore, detail design and follow-on engineering are included as options along with EPC of pipeline-related structures.

The contract has a duration of two years for the completion of pre-FEED and FEED design, covering the SURF part of the development. Including options, the total contract period and value could extend to seven years and US$22.5 million (NOK 200 million), respectively. The engineering work starts immediately and will be run out of IKM's Lysaker office.

Subsea 7 bags Egypt fabrication

Subsea 7 inked a contract, worth between $50-$150 million, with Burullus Gas Co. for the platform extension and tie-in on the first phase of BP's West Nile Delta development of the Taurus and Libra fields offshore Egypt.

Fabrication of the deck extension and spools will be carried out at the Petrojet Maadia yard near Alexandria. Offshore work is scheduled to commence in H2 2016 using Subsea 7's Rockwater 2 as the main hook-up and accommodation vessel with Seven Borealis performing the offshore lift of the platform extension and the heavy construction vessel, *Seven Arctic*, installing the umbilical, Subsea 7 said.

Subsea 7's Cairo office and Global Projects Centre in London will immediately begin engineering and project management work on the project.

Aker, OneSubsea team up for Statoil

Statoil has signed master service agreements (MSA) with Aker Solutions and OneSubsea Processing.

The agreements form the basis for potential new engineering, procurement and construction (EPC) for subsea equipment in the medium term future. An EPC option agreement for subsea production system has also been signed with OneSubsea, including framework agreements for subsea operations services and subsea add-ons.

Statoil says the agreements signed form a good basis for future collaboration with three leading subsea suppliers, thereby simplifying collaboration in the time ahead.

"The agreements constitute a framework upon which the suppliers can continue with optimization and cost reducing measures. Future awards will go to the suppliers who are willing to and capable of continuing the drive for sustained quality, standardization, higher efficiency and lower costs," said Torger Rød, vice president for projects in Statoil.

Aqualis gets Borwin3 gig

Aqualis Offshore has been contracted by Petrofac to perform technical support services for its work on the BorWin gamma topside that is destined for the North Sea.

The scope of work includes preparation of technical specifications for the supply of the leg mating units and deck support units, technical support during the procurement process, review of engineering documents from suppliers, and monitoring of the various stages of the fabrication process. Aqualis Offshore's Singapore office will perform the work.

The converter platform will be installed in the German Exclusive Economic Zone in the North Sea, 130km off the coast at 40m water depth.

Castex to install Hummer jacket

Castex Energy is set to fabricate and install a platform jacket over the Main Pass Block 270 No. 3 BP 1 well on its Hummer exploration prospect, in the Gulf of Mexico. The well is about 50mi southeast of Venice, Louisiana, at 215ft water depth. The anticipated time frame for the fabrication, installation, well completion and testing is approximately 6-7 months.

POSH in Prelude tow

POSH Terasea will tow the Shell Prelude FLNG over 3000nm from Samsung Shipyard in Geoje, South Korea, where it is being built, to Australia, where it will be deployed. It will then position the FLNG vessel before it begins production at the Prelude gas field in the Browse LNG basin, 200km off the northwest coast of Australia. POSH Terasea will be in charge of the overall towage project management. ▪

Global E&P Briefs

operatorships. Applications were received from 43 companies.

Norwegian giant Statoil announced it had broken its 2005 APA record for the most number of licenses awarded during a round, after it took home interest in 24 licenses on the NCS, 13 of those as operator and 11 as partner. Statoil was closely followed by Det Norske with six awards during the APA round; Wintershall followed with four.

The five operators offered licenses in the Barents Sea are Statoil (two licenses), Edison, Eni, and Wintershall.

Wintershall spuds Barents well

Wintershall has started drilling on the Kvalross exploration well 7224/2-1 in license PL811, in the Norwegian Barents Sea. Using the *Transocean Arctic* semisubmersible drilling rig, the well will test two independent targets: the Kvalross prospect with significant oil and gas resource potential within Lower Triassic Klappmyss Formation clinoform reservoir and the Kvalhaan prospect, which has additional oil potential within a Mid-Late Triassic Snadd Formation channel. Kvalross is to the south of OMV's significant Wisting and Hanssen oil discoveries.

Iran sanctions lifted

The six world powers (P5+1) and the European Union (EU) reached an agreement with Iran, lifting sanctions on the country. With the sanctions lifted, Western nations can enter Iran for oil exploration and production for the first time in more than a decade.

Iran is now seeking to ramp up its oil output by an additional 500,000 b/d. According to the US Energy Information Administration's short-term energy outlook, Iran's crude oil production has been flat over the last three years, and in 2015 averaged 2.8 MMb/d. The EIA forecasts that Iran's annual average crude oil production will be 3.1 MMb/d in 2016, and almost 3.6 MMb/d in 2017. And, Iran is seeking further investment. In November, the country offered 52 oil and gas development projects in addition to 18 exploration blocks worth an estimated $30 billion. The projects include 29 new and currently producing oilfields and 23 gas developments with onshore fields accounting for 34 of the projects.

Lundin busy in Malaysia

January was an active month for Lundin Petroleum as the company spud the Bambazon exploration well in Block SB307/SB308, offshore East Malaysia. The well will be drilled by the West Prospero jackup to 1250m below mean sea level, and operations are expected to last 25 days.

Additionally, Lundin has completed the Imbok-1 well off East Malaysia, in the same block as Bambazon, opting to plug and abandon the well after it encountered minor oil shows. Imbok-1 was also drilled by the West Prospero

in a program that began back in December. Both wells are targeting Miocene aged sands.

First oil at Tanjong Baram

Petronas achieved first oil from the Tanjong Baram field, offshore Sarawak Malaysia.

The field, which is estimated to produce an average of 2000 b/d, consists of a platform with production tied into the West Lutong Drilling Platform A (WLDP-A) complex via a flexible production pipeline.

The field is operated under a risk service contract with EnQuest Petroleum Development Malaysia as its operator in partnership with Uzma Energy.

Woodside finds Myanmar pay

Woodside Energy has made a gas discovery at the Shwe Yee Htun-1 exploration well in Block A-6 in the Rakhine Basin, in the western offshore area of Myanmar. Yee Htun-1 intersected a gross gas column of approximately 129m, with about 15m of net pay. The announcement comes as work continues on new offshore 3D seismic acquisition in the country, led by Woodside and BG Group, using the *Ramform Titan* and *Ramform Sovereign* vessels.

"Further analysis will be undertaken to understand the full potential of the play, but this de-risks a number of leads which will now be matured," Woodside said. "This discovery is an encouraging outcome for future exploration and appraisal activity in the area."

Emerging from sanction driven isolation in 2013, the government has awarded 20 offshore blocks to 13 international and nine local companies.

Mitra increases Vietnam stake

Mitra Energy has reached an agreement to take a 35% working interest in the Block 51 production sharing contract, offshore Vietnam. The stake was formerly held by Kuwait Foreign Petroleum Exploration Co. This move takes Mitra's net working interest in Block 51 to 70%. Additionally, Mitra has completed the outline development plans for the Nam Du and U Minh fields and sent them to Petrovietnam before submission for Prime Ministerial approval.

Quadrant strikes pay at Roc-1

Quadrant Energy encountered condensate rich gas at the Roc-1 well, in WA-437-P offshore Western Australia.

Through pressure testing, at least three discrete hydrocarbon columns have been encountered. Formation fluid sampling also confirmed a liquids rich gas with a condensate ratio of 20-40 bbl per million cubic feet of gas, which is being evaluated at the rig site and with lab testing to confirm fluid type.

Fugro to survey Northern Carnarvon

Hess has chosen Fugro to conduct a combined geophysical and geotechnical project in the Northern Carnarvon basin offshore Northwest Australia.

Fugro's work will include seabed and shallow geological investigations including in areas of difficult terrain.

Planned for Q1 2016, Fugro will utilize a Hugin 1000 AUVs to map the seabed for the first phase of the survey. Fugro's geoconsultancy team will also deliver an integrated data model for input to Hess' ongoing analysis.

Ichthys LNG one step closer

Audrey Raj speaks to Japanese gas giant INPEX about its US$34 billion Ichthys LNG development and the key components that make up the offshore production facilities of the project.

In 2000, Japanese exploration and production company INPEX Corp. discovered a giant gas and condensate field in the Browse basin, about 200km offshore Western Australia.

The discovery was the start of what has become a multi-billion dollar liquefied natural gas (LNG) development, known as the Ichthys LNG project.

Operated by INPEX, the development partners are Total and CPC Corp, Taiwan, plus the Australian subsidiaries of Tokyo Gas, Osaka Gas, Kansai Electric Power, Chubu Electric Power and Toho Gas.

INPEX announced its final investment decision for Ichthys LNG in 2012. Currently in the construction phase, first production is scheduled for Q3 2017.

The project is expected to produce 8.9 MTPA of LNG and 1.6 MTPA of liquefied petroleum gas (LPG), along with up to approximately 100,000 b/d of condensate at peak production.

Gas from the Ichthys field will be exported to onshore facilities near Darwin for processing, via an 890km pipeline, and shipped as LNG to Japan and other markets, with long-term sales and purchase agreements already secured.

Meanwhile, condensate extracted from the field will be stored and shipped directly from a floating production, stor-

Ichthys LNG CPF. Photo by – INPEX

The monoethylene glycol injection module is lifted and installed onto the hull of the Ichthys LNG FPSO in South Korea.

ga and offloading (FPSO) facility that is permanently moored at the field.

The FPSO, which features accommodations for up to 200 people, will process and store most of the condensate delivered from the project's floating central processing facility (CPF) – the first semisubmersible production platform in Australian waters according to INPEX – before periodically offloading it to carriers for export.

Construction on the CPF module, weighing 3600-tonnes and measuring 80m x 43m x 28m, began in January 2013. The hull was launched in September 2015 from the Samsung Heavy Industries (SHI) shipyard in Geoje, South Korea, where it is being constructed.

It is currently berthed by a quayside at the shipyard, with work continuing to install the living quarters, plus integrate and commission all equipment in preparation for its sail away.

Floating production facilities

INPEX is and has been involved in numerous LNG developments around the region, such as the Bayu-Undan project in the Timor Sea Joint Petroleum Development Area, the Prelude FLNG development in Western Australia and the Offshore Mahakam block and Tangguh LNG project in Indonesia, to name a few.

"These are all important gas projects contributing to our growth," says Carlo Niederberger, a public relations representative of INPEX. "The knowledge and experience we have gained through these projects is today being applied to the Ichthys LNG project.

"Involvement in multiple projects allows us to continue to secure a balanced portfolio, while establishing appropriate risk management by combining different projects to ensure an optimal balance across key parameters, such as regional distribution and exploration, development and production activities," he explains.

"In this instance, however, INPEX is the first-ever Japanese operator leading a large scale LNG development. The CPF, FPSO, subsea production system, flowlines and flexible risers make up the key offshore production facilities of Ichthys LNG."

Hydrocarbons lifted from the production wells will be collected by the subsea production system and channeled through the flowlines and flexible risers to the floating CPF.

Here they will undergo initial processing to extract condensate and water, and remove impurities in order to make them suitable for transportation to the onshore gas liquefaction plant in Darwin through the gas export pipeline.

Niederberger says the FPSO, positioned about 3km from the CPF, will receive, process and store condensate from the CPF, and periodically offload stabilized condensate to shuttle carriers for direct export to the market, while sending re-pressurized natural gas back to the CPF.

"The FPSO, whose keel was laid in

Installing the Ichthys LNG offshore gas export pipeline.

February 2014, is a key offshore component of the Ichthys LNG project. Designed to hold more than 1 MMbbl of condensate, the FPSO will be used for condensate dewatering, stabilization, storage and export. So, its importance cannot be overstated," he says.

Construction of the 336m x 59m FPSO unit, being built in Korea by Daewoo Shipbuilding & Marine Engineering (DSME), is proceeding according to schedule. This year the facility will continue to undergo installation work and will then be towed 5600km to the Ichthys gas-condensate field, where it will be permanently moored for 40 years on a fixed turret from SBM Offshore.

Working the field

The Ichthys field's estimated reserves are some 12 Tcf of gas and 500 MMbbl of condensate. To extract gas and condensate from the field, wells are being drilled in the Browse basin.

The drilling rig *ENSCO 5006*, which arrived at the field after undergoing major upgrades in Singapore, spudded the first development well in February 2015.

Initially targeting the Brewster formation with 20 production wells, drilling operations were being undertaken on 13 separate wells as of October 2015. The wells are being drilled into reservoirs about 4000-4500m beneath the seabed.

Economical benefits

Niederberger says the Ichthys LNG project is vitally important to Australia and particularly to the Northern Territory economy.

"In fact, in constructing the project, INPEX and its partners will contribute more than US$8 billion (AU$13 billion) to the Australian economy and $5.7 billion (AU$8.2 billion) in the Northern Territory alone," he says.

"With a 40-year plus life span, the Ichthys LNG development offers a multi-generational economic opportunity. During operations, INPEX expects to employ approximately 1200 personnel, including about 750 to oversee productive activities, along with services from a range of businesses to support the operation.

"The project is also a key part of the Northern Territory government's plan to establish the area as the gateway to Asia and is expected to deliver considerable benefits," Niederberger continues.

"This includes new business opportunities, major new and improved infrastructure and expanded economic, employment and training outcomes."

Future plans

To ensure sustainable growth in the medium-to long-term, INPEX plans to focus first and foremost on safely bringing Ichthys LNG to production.

"This will be followed by efforts to proceed with the INPEX-operated Abadi LNG project offshore Indonesia, with the support of the Indonesian government and other project stakeholders," Niederberger says.

"INPEX also plans to strengthen its gas supply chain and reinforce its renewable energy initiatives. Specifically, the company will aim to reach a gas supply volume in Japan of 25 Bcm per year by the early 2020s.

"We are looking to also promote efforts to commercialize renewable energies, and reinforce research and development activities for the benefit of coming generations, and aim to become an integrated energy company with natural gas at its core," Niederberger concludes. **OE**

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Finding meaning in standardization and replication

To create meaningful cost reduction – or value creation – the industry will need to be more aligned in its understanding of what exactly terms like standardization and fit-for-purpose mean. Meg Chesshyre reports.

There needs to be common terminology and a clear understanding of the different drivers across the entire industry if the goal of significant and meaningful cost reduction (or value creation) is to be achieved, industry consultant Alex Hunt, told a recent London conference.

Alex Hunt

Hunt is the founder of Woodview Technology, a consultancy specializing in the identification, development and implementation of emerging and new technologies for the oil and gas industry.

In response to the current focus on cost reduction, a number of possible solutions are receiving attention, he told the Subsea Integrity and Efficiency Conference, organized jointly by Subsea UK and the Society of Underwater Technology. These include fit-for-purpose functional specifications, catalog engineering, replication, standardization, equipment reuse, increased use of new technology and improved collaboration. However, following a series of recent workshops, it has become clear that these have different meanings to different companies.

For example, cost reduction implies capex to some operators, but life-of-field ownership costs to others. A more appropriate term might be value creation rather than cost reduction.

Alan Peek

Similarly, standardization means interchangeability to some companies and interoperability to others. "We tried to have standard contracts for joint industry research projects. It was an absolute nightmare," Hunt said. He put up a slide published recently by Ernst and Young, showing that non-collaborators are actually more efficient than collaborators. The cost overruns are less.

Replication is a subset of standardization. It has been used by Statoil on 13 fast-track projects in the last 3-4 years. The Gulf of Mexico uses standard platforms, and Brazil uses replication for its floating production, storage and offloading (FPSO) vessels, partly driven by the limitation of Brazilian shipyards.

There is still a lack of awareness of technology readiness levels (TRL), however, with many companies using the term "proven technology" without stating the TRL that this implies, Hunt said. What is new technology? Hunt had heard low dosage hydrate inhibitors referred to as new technology in a recent presentation. They have been around and commercially

The replicated Heidelberg spar onboard Dockwise's *Mighty Servant I*. Photo from Archive Publication

In-Depth

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 [illegible]	72	72	48	
Deep [illegible]	11	29	15	
Ultradeep [illegible]	17	16	13	1
Total	[illegible]	[illegible]	76	1
Start of 2016 / Date comparison	1?? / 1	134 / —	72 / 4	1

[illegible]

Reserves in the Golden Triangle

by water depth 2016-20

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	8	[illegible]	333.20
Deep	1	1204.00	1596.00
Ultradeep	[illegible]	11,715.00	12,893.00
United States			
Shallow	[illegible]	[illegible]	134
Deep	20	1022.27	1048.48
Ultradeep	76	[illegible]	1300.00
West Africa			
Shallow	129	[illegible]	16,948.62
Deep	38	5412.50	6650.00
Ultradeep	[illegible]	[illegible]	2800.00
Total [illegible]	[illegible]	29,143.98	43,179.30

Greenfield reserves

2016-23

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow [illegible]	[illegible]	36,250.69	482,005.76
Deep [illegible]	[illegible]	[illegible]	145,822.62
Ultradeep [illegible]	64	17,492.80	69,900.00
Total	[illegible]	[illegible]	566,716.53

Pipelines

(operational and 2015 onwards)

	(km)	[illegible]
<8in.		
Operational/installed	42,207	[illegible]
Planned/possible	24,553	[illegible]
	66,760	[illegible]
8-16in.		
Operational/installed	83,557	[illegible]
Planned/possible	49,935	[illegible]
	133,492	[illegible]
>16in.		
Operational/installed	94,030	[illegible]
Planned/possible	44,631	[illegible]
	138,661	[illegible]

Production systems worldwide

(operational and 2015 onwards)

Floaters		[illegible]
Operational	274	[illegible]
Construction/Conversion	50	[illegible]
Planned/possible	320	[illegible]
	644	[illegible]
Fixed platforms		
Operational	9278	[illegible]
Construction/Conversion	92	[illegible]
Planned/possible	1406	[illegible]
	10,776	[illegible]
Subsea wells		
Operational	4837	[illegible]
Develop	422	[illegible]
Planned/possible	6536	[illegible]
	11,795	[illegible]

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	[illegible]	28,959.04	32,122.38	19,548.43	14,115.83	27,385.17	27,408.20
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-
Deep	[illegible]	1081.38	5481.04	2271.55	4592.11	6153.51	16,472.83
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
Ultradeep	[illegible]	2037.21	3057.88	3228.63	5443.92	7477.93	10,596.42
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-
Total	[illegible]	32,327.63	40,380.22	25,008.61	24,151.64	41,016.61	54,377.45

18 January 2016

available for 15 years, he points out.

Successful collaborations will require the active involvement of customers as well as the supply chain. It is unlikely that many of these initiatives will make significant progress if companies continue to use the same terms, but with different meanings and expectations of the outcomes. There has to be an alignment of goals between customer and client, Hunt said. "You can't have a Saville Row suit at department store prices," he said. Hunt concluded with a message to the oil companies and large suppliers, less important for the small-to-medium sized enterprises, who know it already. "Don't talk the talk, if you can't walk the walk."

Moral obligation

The industry has a moral as well as an economic obligation to maximize total production from its aging assets, is the view of Alan Peck, vice president, subsea control and communications, Proserv. He said that Proserv had developed an innovative way of retrofitting an established original equipment manufacturer's subsea control module with its Artemis 2G subsea electronic module. This technology can be deployed on older infrastructure using retrofit and coexist techniques to secure and enhance production without costly new umbilical lay or complete system change out.

Peck examined a number of case studies where such brownfield subsea control system enhancements have been implemented. In the North Sea, Proserv upgraded CNR's existing subsea control system on the Tiffany field enabling it to add two wells without a full system change. On Statoil's Troll C, the Proserv control and monitoring system dramatically improved the system capability using existing infrastructure. A subsea controls electronic module and surface retrofit at Ithaca's Anglia field enabled production to continue for from an otherwise unproductive field. A retrofit open communications hub was supplied for Shell's P6 project in the Gulf of Mexico.

Optimizing water injection

A significant number of North Sea fields are under-performing in terms of production targets, due to poor reservoir pressures, said Scott Wilson, manager, integrated solutions, OneSubsea.

Wilson outlined a single water injection booster pump application, developed by OneSubsea, which can be installed onto a live or shut-in producer well to increase reservoir pressure and therefore, production, allowing an immediate fall in lifting costs. Such pumps can be leased from the supplier, negating capex during these difficult market conditions.

By interrogating relevant reservoir data, a water injection pump can be accurately deployed to increase production rates, which, given the predominance of ullage within the central and northern north sea systems infrastructure should be readily accommodated allowing immediate benefit to the operators' projects, covering all aspects of development from concept evaluation through to final commissioning.

New functionality through net shape?

Recent developments in net shape manufacture enable new functionality in offshore components, said Charley Carpenter, Net Shape technology manager for the Manufacturing

All in the family

Many companies often try to replicate successful prior projects and one such company that has managed to do so is Houston-based independent Anadarko Petroleum.

The company opted for a "design one, build two" strategy when it came to developing the Lucius and Heidelberg fields in the deepwater Gulf of Mexico (*OE: August 2015*), choosing to use a standalone spar for each. Lucius came online first, in January 2015, and Heidelberg followed, just last month (january 2016) – three months earlier than expected.

The Lucius field is about 275mi southeast of Galveston, Texas, and includes portions of Keathley Canyon blocks 874, 875, 918 and 919 in the deepwater Gulf of Mexico, in about 7000ft water depth. The 110ft-diameter spar was designed for 80,000 bo/d and 450 MMcf/d of natural gas. Reserves will be produced through six initial wet tree wells.

Heidelberg is in Green Canyon 859, some 390mi off Texas, and consists of six production wells, one standalone truss spar, two drill centers, dual looped 8in flowlines, and 16in oil and gas export lines. The 80,000 bo/d, 80 MMcf/d-capacity Heidelberg spar is able to operate in water 5300ft deep. It has a maximum topsides operating weight of 16,000-ton, and a hull weight of 23,000-ton. The spar is 605ft-long with a 110ft-diameter.

According to Anadarko, the company was able to keep the Heidelberg design 87% identical to Lucius. And Anadarko kept much of the same processes in place. Heidelberg's topsides, like Lucius, were constructed at the Kiewit yard in Ingleside, Texas. The pair's hulls were constructed by Technip in Pori, Finland. To reach Texas, the Heidelberg spar sailed 7300nm over 27 days from September to October 2014 on Dockwise's *Mighty Servant I*. The same journey its sister spar, Lucius, made in 2013.

Anadarko operates Lucius with 23.8% interest. Its partners are Freeport-McMoran (25.1%), ExxonMobil (23.3%), Petrobras (11.5%), Eni (8.5%), and Inpex (7.75%). Anadarko operates Heidelberg with 31.5% interest. Its partners on that project include Cobalt (9.375%), Eni (12.5%), ExxonMobil (9.375%), Freeport McMoRan (12.5%), Marubeni (12.75%), and Statoil (12%).

—Audrey Leon

The Lucius spar. Anadarko Petroleum kept the Heidelberg design 87% identical to Lucius'.
Images from Anadarko Petroleum.

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	108	82	26	75%
Jackup	401	278	123	69%
Semisub	153	103	50	67%
Tenders	31	20	11	64%
Total	693	483	210	69%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	35	32	3	91%
Jackup	23	6	17	26%
Semisub	18	15	3	83%
Tenders	N/A	N/A	N/A	N/A
Total	76	53	23	69%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	16	5	11	31%
Jackup	120	75	45	62%
Semisub	35	14	21	40%
Tenders	21	14	7	66%
Total	192	108	84	56%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	21	7	75%
Jackup	54	41	13	75%
Semisub	31	28	3	90%
Tenders	2	1	1	50%
Total	115	91	24	79%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	48	42	6	87%
Semisub	45	32	13	71%
Tenders	N/A	N/A	N/A	N/A
Total	93	74	19	79%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	108	87	21	80%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	113	90	23	79%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	21	2	91%
Jackup	23	17	6	73%
Semisub	10	7	3	70%
Tenders	8	5	3	62%
Total	64	50	14	78%

Eastern Europe

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

Source: InfieldRigs

[illegible] January 2016

[illegible]

Artemis 2G subsea electronic module.
Photo from Proserv.

Technology Centre (MTC). This includes introducing next generation alloys, bi-material components and parts with complex un-machinable design enabling robust manufacture of more resilient components for future subsea applications. He described net shape manufacture using powder hot isostatic pressing (PHIP) as "undoubtedly a game-changing technology." "When you produce a component by a net shape manufacturing method it comes out the right geometry, and all you have to do is tidy up the mating faces," he said.

With improvements in capsule design and the introduction of computer process modeling in the early 2000s, the complexity and material efficiency of PHIP components has increased. This has led to the introduction of material efficient PHIP components into the market such as manifolds, valve bodies and wye pieces with reduced inspection requirements, enhanced corrosion resistance and greater functional performance when compared with traditional forged products.

The MTC in Coventry, England, develops next-generation powder metallurgy manufacture routes for the high value manufacturing sectors. Carpenter is responsible for the coordination of a dedicated team of net shape research engineers within the UK's National Centre for net shape and additive manufacture.

Decommissioning – an attractive option

In the current low oil price environment decommissioning is becoming more of an attractive option, Iva Erkic, an analyst with Douglas Westwood, told the conference.

"Decommissioning might actually take place on the basis that there are around 800 plugged and abandoned wells and around 250 topsides in the North Sea alone potentially qualifying for decommissioning over the next five years."

She said that in a low price environment operators would like to reduce risk, and that one way to do this was to remove decommissioning liabilities from their balance sheets.

A new incentive for decommissioning is the fact that service companies that carry out decommissioning are now idle, and therefore, might be able to provide services at a lower cost. Delaying decommissioning costs more in the long run (higher maintenance, engineering + removal costs). OE

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Staying of the game

Despite slower than anticipated demand for well intervention services, service firms are ploughing ahead with new designs and solutions to help operators get more out of their wells. Elaine Maslin highlights some of the activity in the market.

In theory, there's a huge global market for subsea well intervention, with a limited number of vessels out there to do the job.

"If you look at how many subsea wells there are, based on 20 days for one intervention, only 6% of wells can have interventions on them per year with the amount of well intervention vessels (not including drilling rigs) we have today," says Robert Plat, principal consultant at Netherlands-based Royal IHC, speaking at the Offshore Energy conference in Amsterdam in late 2015.

The cost also appears to be attractive, particularly as it relates to increasing production from existing assets.

"The incremental cost for additional oil volumes will be lower than the cost per barrel for development of new fields," says Erik Dietrichson, manager – Eastern Region Well Intervention Service, FMC Technologies. "If the cost for a typical RLWI operation is US$5 million and the incremental increase in volume following a successful operation results in an additional 1 MMbbl, the cost per barrel will be $5. Development cost of a medium sized new field offshore Norway is typically $50-60/bbl."

Yet, the potential hasn't quite yet translated into actual work. Dietrichson believes part of the reason can be found if you look at who is sitting on the some 5000 subsea wells in operation globally. "There are only 6-7 oil companies operating more than 200 subsea wells," he says. "Two companies are dominating the market; Petrobras and Statoil are responsible for 800-900 subsea wells each... [with] all of these in their respective home country. Shell, BP, Total and ExxonMobil have 300-400 subsea wells each, but these are spread over 4-8 countries. The consequence is that the biggest operator in West Africa, Total, is one-third the size of the Brazilian and Norwegian markets and the biggest operators in the US Gulf of Mexico are one-tenth the size of the Brazilian and Norwegian markets."

The result is insufficient market volumes for vessels in most markets. It has also meant there are growing numbers of firms offering smaller, cheaper, flexible solutions to take up parts of the subsea well intervention market, particularly around fluid intervention.

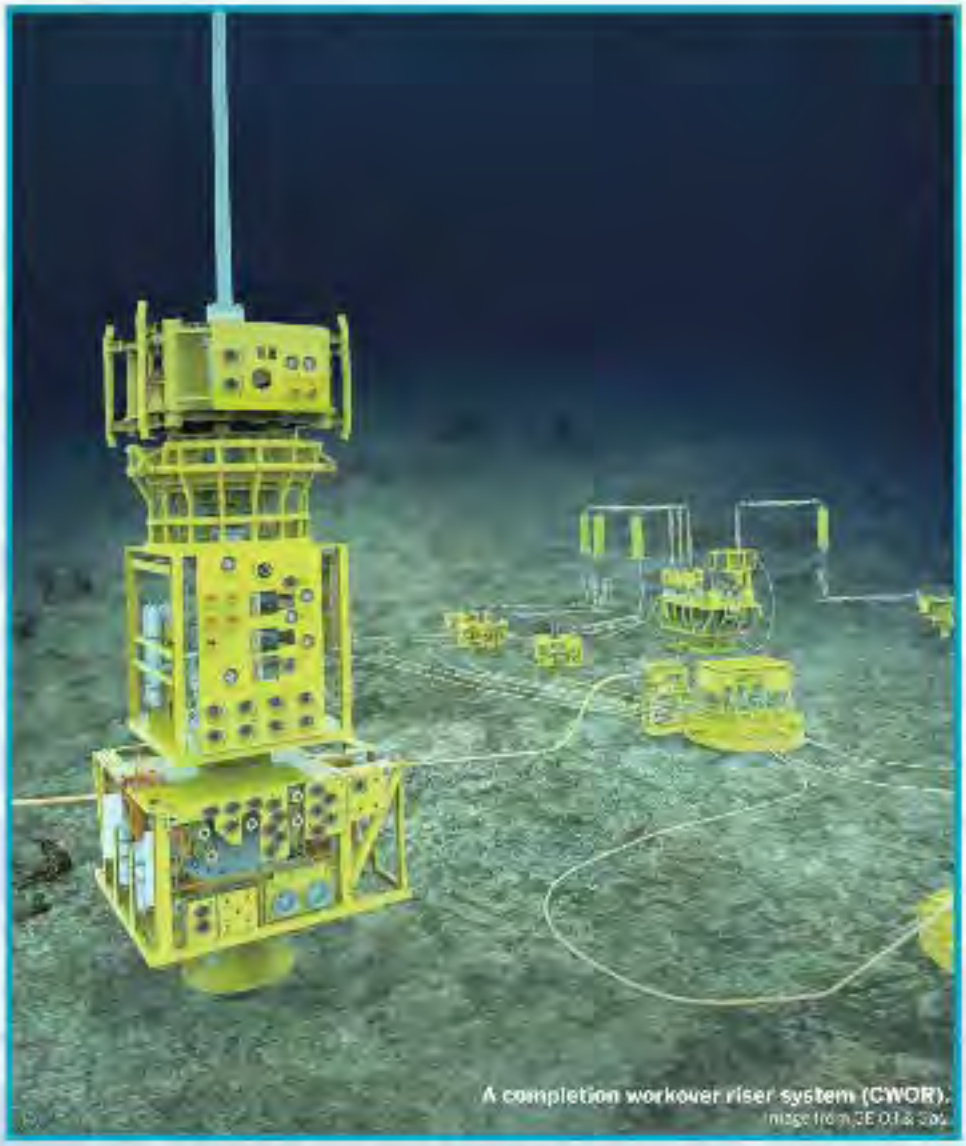
GE

GE Oil & Gas has been quietly building up its expertise in well intervention, throughout the subsea well lifespan, from installation to plugging and abandonment, under the banner WellAccess. Notably, in May 2015, the firm struck up a memorandum of understanding with Enpro Subsea for work with its Integrated Subsea Sampling and Injection (ISSI) system.

Then, in October, GE Oil & Gas bought Norwegian subsea well intervention firm Advantec, including its installation workover control system (IWOCS) capabilities and IWOCS fleet. Drawing on both firms, GE Oil & Gas sold its first subsea fluid intervention system into the US Gulf of Mexico market in 2015, with deployment expected this year and it plans to introduce it to offshore West Africa after that. It will offer services for fluid intervention and scale squeezes and stimulation, etc.

Aberdeen-based Enpro, previously known as Canaco, was

ahead



A completion workover riser system (CWOR). Image from GE Oil & Gas

founded by the team behind the MARS (multiple application reinjection system) product bought by Cameron in 2007. Advanten was set up in 2005 to provide electro hydraulic systems, including IWOCS, with offices in Norway, the UK, Lithuania and the US.

"[Using Enpro's ISSI] instead of going through a pressure containment system on the tree, you go in through the spool piece on the side of the tree and inject in bulk. This debottlenecks the plumbing," says Carl Roemmele, WellAccess leader, GE Oil & Gas. An ROV is used to "plug it in" and suddenly you don't need a rig or intervention vessel, he says.

What's good about Advantec, Roemmele says, is that is has developed a Lego-block type of service, where its standard products, which make up the biggest rental fleet outside the US Gulf of Mexico, can be brought together to build systems in a third of the time that they would otherwise. It also has control over its manufacturing, which was attractive to GE, Roemmele says.

The WellAccess expansion doesn't stop there. The firm bought two completion workover riser (CWOR) systems from an operator last year, expanding its fleet, with which it's looking to work with clients to create a club model, where operators have access to a bank of equipment and services, instead of paying one off project by project costs. WellAccess is also offering more subsea test tree (SSTT) services and has been working in decommissioning, Roemmele says, and not just on GE trees. "We are moving from a product company to a services company," he says. An example of this is a contract with Eni in Ghana on the OCTP (Offshore Cape Three Points) project to supply IWOCS and landing strings and potentially fluid intervention using Enpro's fluid intervention equipment through field life. The firm is putting a new base in Ghana for the work.

Magma

The relatively new kid on the oilfield block, Magma Global is using composites technology developed for the superyacht industry to make flowlines and jumpers, and ultimately risers, for the oil and gas industry.

The m-IDP system on a backdeck.
Image from Magma Global

The Portsmouth, UK-based firm is working with Peterhead-based Maritime Developments Ltd. (MDL) to produce a portable well intervention package, using a compact vertical lay system with a built in reel. The first package is set to be shipped to the US Gulf of Mexico later this year. It will have a 3200m, 3in m-pipe for light well intervention in deepwater with 5-15,000psi operating pressures and corrosive fluids. The idea is that it could be deployed on a vessel of opportunity, along with a lower riser package, emergency disconnect package and ROV, etc., for intervention operations such as scale-squeeze.

The package will include Magma's m-pipe, a high-strength carbon fiber pipe manufactured using PEEK polymer, which gives improved high-pressure and high-temperature (up to 200°C) and sour service capability, including H_2S. And, compared to steel-based products in deepwater, it's also better able to handle brine at pressures up to 10,000psi, compared to coiled tube. It's also about 10 times lighter than steel pipe, enabling deployment from smaller vessels, Magma says.

The m-pipe is manufactured by combining Victrex PEEK polymer, high grade carbon fiber and S-2 glass fibers to the outside of a PEEK pipeline, using high-powered laser additive manufacturing, due to the heat required, and enabling bespoke tailoring to specific solutions. This includes adding more material to create strengthened end fittings, in order to remove the need for bend stiffeners, etc.

"The hydraulic well stimulation market is predicted to increase by 43% to US$4.3 billion by 2018 [Data: MarketsandMarkets]," says Andrew Kerry-Bedell, marketing manager, Magma Global. "However, this type of well intervention has been held back in its expansion by several key factors. These include relatively high dayrate costs from the use of rigs rather than smaller intervention vessels, combined with operational risks and complexities due to the short fatigue life and pressure and flow rate limitations of the steel coiled tube units usually deployed. These factors have become even more problematical with the higher pressure and higher flow rate requirements of fluid delivery for well intervention in increasingly deeper waters."

He says Magma's package allows operators easy access to a high-pressure, high flow rate hydraulic intervention pumping system on a dayrate rental basis, making it commercially attractive.

Ulstein

The supply chain has not given up on creating a high-spec well intervention vessel, however. German firm Herrenknecht Vertical and Dutch ship designer and builder Ulstein have been working on a heavy well intervention vessel design.

They describe it as a well intervention vessel, with capabilities close to a drilling vessel, but with lower capex and opex. It would be a $100 million vessel with $60 million topsides working on a $175-225,000 dayrate (figures given in October 2015), depending on the function and how dayrates are defined, according to a presentation at the Offshore Energy conference.

It would be able to perform wireline, slickline, and coiled tubing operations, plus pull tubing and work with risers in water depth up to 2500m and 35,000ft drilling depth. In addition, it would be able to perform slimhole drilling and Xmas tree installation.

Bram Lambregts, marketing and sales manager, Ulstein Design & Solutions, said the two firms had looked closely at system integration and the layout of the vessel through network integrity theory, in order to combine equipment and functionality that needs to be close to each other. "The result is a compact vessel design because of compart functionality and automation," Lambregts says.

The vessel has automated riser handling, including a catwalk lift system and skidding, a riser pipe combi catwalk and an ability to continuously trip 30 risers/hr. Pipe handling, up to 27in, is also automated, with integrated pipe storage and iron roughneck and continuous tripping at 2000ft/hr. It has an HVC Tern Invader 750 drill tower, a rigless hoisting system, using an A-frame, and integrated heave compensation. On the rig floor, it has a 1000kW top drive with top hole drilling capability, 49.5in auxiliary rotary table and multi-functional iron roughneck with riser handling guider arm.

The design is 155.4m-long, with a 18.4m-beam and 9m draft. It will be able to transit at 15 knots, and will be DP3, with SPS and MCDO classification. It will have a helideck, 4000sq m deck space, Xbow design, be able to carry 4000-tonne of drilling consumables, and will have a 300-tonne BOP crane, an 18¾in BOP, a 150-tonne AHC crane, accommodation for 100 people, retractable thrusters, and ROV hangar.

"We have been looking at which equipment can be used as multi-purpose equipment," says Dennis Vollmar, from Germany's Herrenknecht Vertical. "We have been thinking how to accommodate all needs of the well intervention tower in to

Uistein's heavy well intervention vessel design. Image from Uistein

OSD-IMT well intervention vessel design. Image from OSD-IMT

BOP gantry crane. The benefits are that it's skiddable and you can stack all parts in the BOP stack area, which opens up the aft deck of the vessel." This opens it do performing plugging and abandonment work P&A or increasing pipe storage.

OSD-IMT

OSD-IMT, a UK division of Netherlands-based Offshore Ship designers, is working on a riserless light well intervention vessel. The firm announced last July it is designing two, 120m IMT9120 riserless light well intervention/inspection repair maintenance repair vessels for Austin Offshore, the shipping arm of Upstream Drilling, based in Singapore. They are due to be able to each deploy three ROVs, have a 250-tonne AHC crane, and travelling gantry well intervention tower system. The 9500 dry weight tonnage, 120m-long vessels will have accommodation for 140. The vessels are due to be built by China Merchants Industry Holdings, Hong Kong.

Helix

Meanwhile, Helix Energy Solutions has also been looking additional potential uses for its vessels, including plugging and abandonment (P&A) and well construction.

Speaking at Offshore Energy, Helix Well Ops' Phil Bosworth outlined how well intervention vessels can help reduce costs in P&A campaigns, either by running campaigns using Cat A vessels or using heavy duty Cat B well intervention vessels for full P&A work.

The advantage of using a Cat B vessel is being able to access the tower more easily than on a rig and to change between wireline and coiled tubing faster, Bosworth says. Cat B vessels could also be brought on well construction scopes, for top hole drilling, installing upper completions and Xmas trees as well as well stimulation and flowback, he says.

"Having have a rig and a well intervention vessel working side by side throughout the development work is something we are looking at," Bosworth says. "A Cat B vessel can do 5-50% of well construction cycle. We had been targeting intervention, we are now focusing on taking work off the drilling rig. This enables lots of options and flexibility when scheduling new field developments, because you can batch construct wells more easily and if something goes wrong you also have flexibility. It gives flexibility in well construction schedule." This could also save 5-30% drilling costs, Bosworth says.

Helix has two Cat B vessels being built for use in Brazil. The *Siem Helix 1* and *Siem Helix 2* monohull vessels are being built by Siem Offshore at the Flensburger shipyard in Germany, which Siem now owns, and are due to be delivered this year and go on seven-year contracts to Helix. **OE**

It's not all subsea

Norway's E Plug was been named 2015 winner of the Intervention & Coiled Tubing Association (ICoTA) European Chapter's Innovation Award, presented during the SPE ICoTA European Well Intervention Conference in Aberdeen late 2015.

Scott Mitchell, Chair of the European Chapter of ICoTA (left), presents the award to Thomas Johansen, CEO of E Plug.

E Plug's 5½in TorcPlug is a single run multiple set and release plug technology which enables a plug to be set and repositioned or reset multiple times, as opposed to conventional bridge plugs. The TorcPlug is run on an e-line with an electrical manipulation tool (EMT), which transfers torque to the plug actuating the centralizer, slips and setting element. By use of rotational force, the plug is compressed and retracted, allowing the plug to be set and repositioned multiple times. TorcPlug also has an independently operated internal valve, which can be used to equalize across the plug before pulling it.

Developed by E Plug, with technical support from Statoil and Welltec, and additional support from E Innovation, Innovation Norway and the Research Council of Norway, TorcPlug went into commercial use offshore Norway in August 2015, on Statoil's Statfjord field. It was run in hole and set and released at three different depths to verify tubing integrity and location of a leak point.

The other finalists for the 2015 award were CapWell and Interwell. CapWell was shortlisted for its development of Capline, a new way to reduce the complexity of well interventions to make them more efficient. Interwell, a previous winner of the award, has developed a wireless barrier verification system to meet the demand for barrier plug integrity assurance. •

Battling fatigue

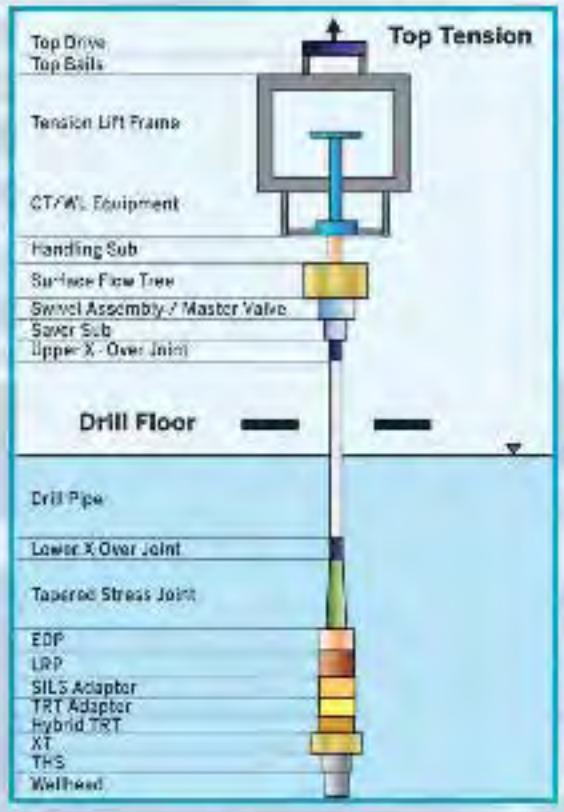
2H Offshore's Mike Campbell and John Gaver discuss design challenges of riserless well intervention systems and best practices.

Riserless coiled tubing well intervention is growing in popularity within the industry. These systems have the benefit of being significantly less expensive when compared to traditional well intervention systems. While labeled "riserless," they are in essence riser systems and should be treated accordingly. However, they have additional unique design challenges. Due to high plastic strains in the reeled coiled tubing and dynamic loading at the hangoff location, fatigue failure is a sizeable risk.

Traditional invention risers are typically comprised of a top tensioned 5-7in diameter pipe. Coiled tubing is generally deployed inside the intervention riser. In riserless systems, the outer pipe is removed, leaving just the coiled tubing. A traditional intervention riser stack-up (left side) is compared to a riserless intervention system (right side) in the Figure 1.

The reeled coiled tubing is deployed over a sheave through the vessel's moonpool or over the vessel's side. The fluid conduit extends from the vessel to an elevation of approximately 50-75ft above the mud line. A clump weight is attached to the bottom of the coiled tubing to limit the system's dynamic response during installation and straighten the coiled tubing as it passes over the sheave. The bottom of the coiled tubing is connected to a subsea assembly on top of the tree via a slick flying lead.

The primary area of concern in these systems is the region of coiled tubing in contact with the turn-down sheave. A typical subsea pumping operation requires the coiled tubing to undergo multiple plastic



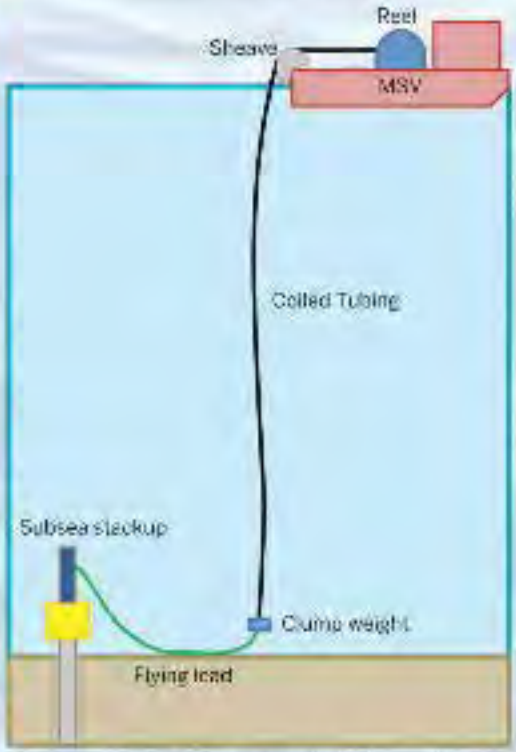


Figure 1 – Traditional vs riserless intervention systems. Images from 2H Offshore

strain cycles as it is deployed and retrieved. Additionally, the coiled tubing will undergo dynamic fatigue loading during operation from the vessel motions and interaction with the sheave. The geometry of the sheave will dictate both the strength and fatigue response of the system. A smaller sheave radius will induce the following:

1. Increased low cycle fatigue damage induced from reeling during deployment and retrieval.

2. Increased residual stresses in the suspended region of the coiled tubing.

3. Increased strains in "on sheave" section of the coiled tubing induced by vessel motions.

As a recommendation, the minimum sheave diameter should be 48 times greater than the outer diameter of the coiled tubing, as per NORSOK D-002 Section 7.5. This sizing ratio provides a good balance between the system footprint and coiled tubing structural performance.

The critical sheave locations (A, B, and the fatigue hotspot) are shown in Figure 2. When calculating the fatigue response at each location, the peel-off effect must be correctly modeled. If it is assumed that the coiled tubing is tangent to the top and side of the sheave at Point A and Point B, the fatigue hotspot would, in theory, instantly transition from having a finite curvature to having infinite curvature. This would result in a fatigue life measured in minutes rather than weeks at Point B. In actuality, the stiffness of the coiled tubing causes a much more gradual "peel off" region. The points of peel off initiation are identified with green arrows in Figure 2.

A fatigue hotspot, existing just below Point B, is the location where failure is most likely to occur. Detailed analysis of the fatigue hotspot is suggested before operations commence.

As discussed above, the fatigue hotspot will experience low cycle fatigue (defined as <1000 cycles to failure) during installation/retrieval and high cycle fatigue (defined as >1000 cycles to failure) during its service life. Calculating high and low cycle fatigue independently from each other is routinely performed. However, this approach can underestimate the fatigue capacity of the system, and correctly accounting for combined high and low cycle fatigue is critical in this application.

Miner's Linear Damage Rule is a linear method of combining fatigue damage, which is useful if the damage is in the same fatigue domain (high or low cycle).

However, Miner's rule becomes inaccurate when combining low and high cycle fatigue. Therefore, its sole use is not appropriate when analyzing riserless subsea pumping systems. Two fatigue damage summation rules which are useful for combining high and low cycle fatigue are discussed below.

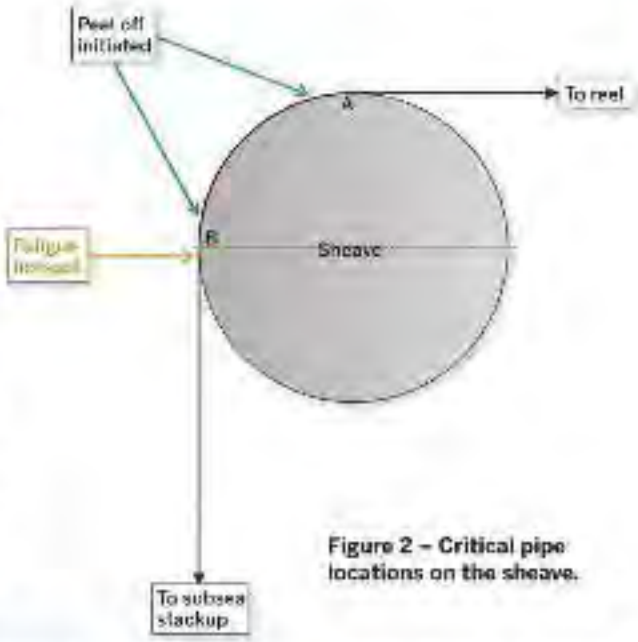


Figure 2 – Critical pipe locations on the sheave.

Non-linear fatigue combination methods

The power rule and other non-linear damage summation laws can be used to convert the low cycle reeling fatigue into an equivalent high cycle fatigue damage rate. This equivalent high cycle fatigue damage can be summed using Miner's rule with the high cycle operational fatigue damage to provide an overall fatigue damage. High cycle and low cycle fatigue must be calculated independently for these damage summation rules to be applicable. The power rule and other non-linear damage summation laws are experimentally fit curves and require some material testing. The power rule is fit to the material type and geometry through the use of an exponent, p. When no experimental data is available, the power law can still be used by assuming a conservative p-value.

Additionally, the power rule requires knowledge of the loading sequence to be used. This is suitable for riserless well intervention, however, because the load sequence is predictable. Assuming all low cycle fatigue damage occurs prior to any high cycle fatigue damage will result in a conservative fatigue damage accumulation value.

Periodic overload curve

While the power rule and other non-linear fatigue damage accumulation laws only serve to combine high and low cycle fatigue, the periodic overload approach takes into account the effect of the overload cycles (reeling cycles) on the operational cycles. The periodic overload strain-life curve is developed using tests that apply periodic overloads at regular intervals so that all the applied small cycle stress/strain ranges are fully effective. When the specimen fails, an equivalent fatigue life for the small cycles can then be obtained using a derivative of Miner's rule.

An effective strain-life curve accounting for periodic overloading is thus generated. This curve is represented by the red curve below the blue constant amplitude strain-life curve in

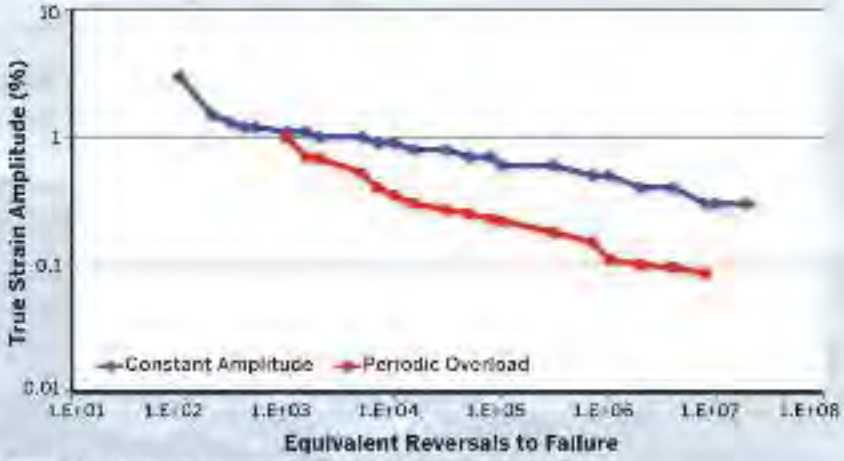


Figure 3 – Periodic overload strain-life curve.

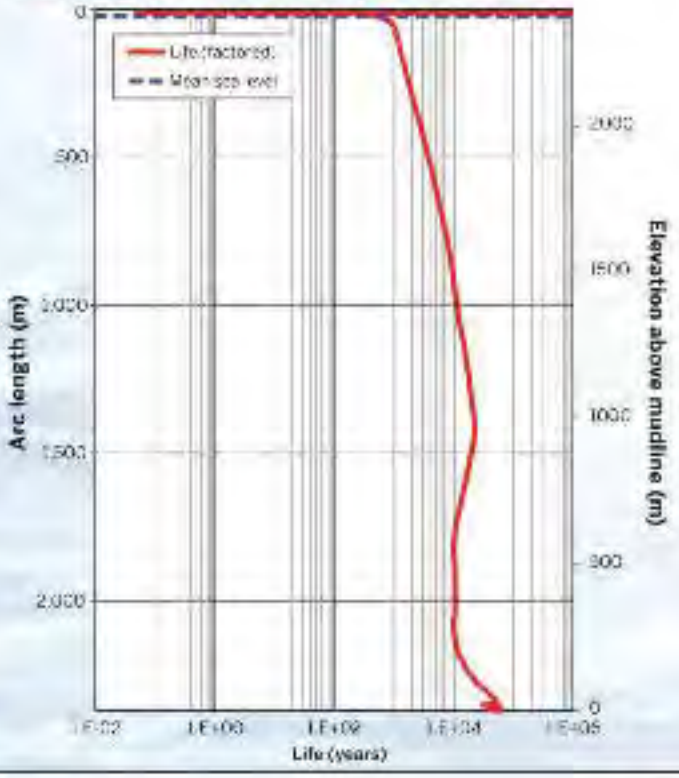
Figure3. The constant amplitude and periodic overload curves are the same when their strain amplitudes result in low cycle fatigue. However, the curves diverge as the overload cycles become significantly more damaging than the operational cycles. This effectively de-rates the fatigue life.

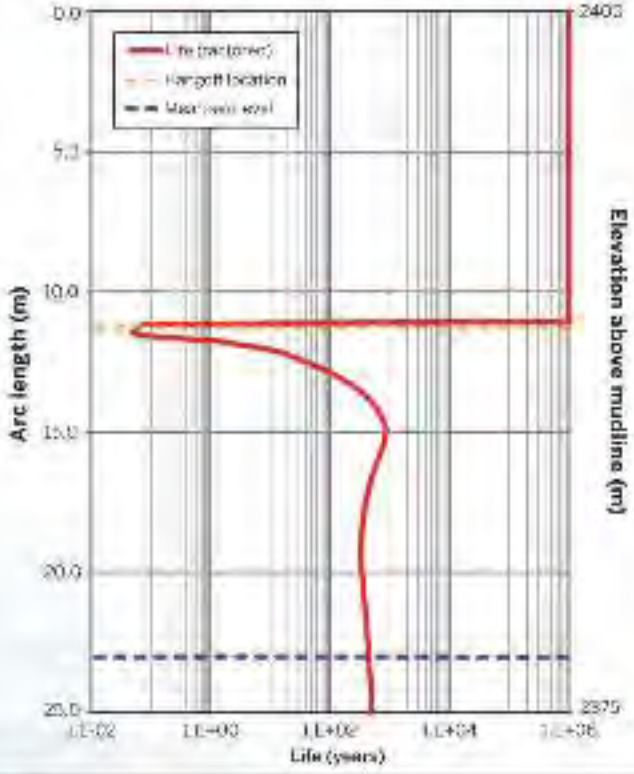
The fatigue response of an example case study from a Gulf of Mexico riserless intervention system is shown in Figure 4. The plot on the left shows the full length of the tubing, while the plot on the right shows a zoomed in view of the hangoff region. The dotted blue line represents the water line, and the dotted orange line represents the fatigue hotspot on the sheave.

The average fatigue life along the entire length of the coiled tubing is approximately 1000 years, but the fatigue life drops to approximately three weeks at the hotspot location. However, this fatigue damage is extremely localized and can be managed. To mitigate risk of fatigue failure, implementation of over-reeling is recommended, where the coiled tubing is incrementally reeled in at predefined intervals.

In conclusion, the reduced cost of riserless well intervention is becoming more attractive to oil field operators in the current oil market. However, there are challenges that must be addressed. In addition to complying with existing riser standards, there are uncertainties surrounding the strength and fatigue response at the sheave hangoff location. This article has proposed some methods of more accurately assessing the

Figure 4: **Case study – Fatigue life**
Sheave deployed subsea pumping system





relationship between high and low cycle fatigue in the coiled tubing and operational strategies for mitigating the risk of fatigue failure. OE

***Mike Campbell** is a vice president at 2H Offshore and has focused his career on riser and conductor systems for close to 20 years. He has extensive experience in the specification, design, riser monitoring and integrity management of a variety of riser and subsea systems. Campbell is also a director of Ciarus Subsea Integrity Inc. He is a graduate from the University of Sheffield and is based out of Houston.*

***John Carver** has worked as an engineer at 2H Offshore for 2.5 years. He has participated in multiple coiled tubing and riserless well intervention workshops. He is an active member of the API 17G2 – Riserless Well Intervention Committee and presented on riserless well intervention at the Offshore Well Intervention Conference held in Houston last fall. He is a graduate from Georgia Tech and is based out of Houston.*

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Currents and cold fronts

Jerry Lee looks at how to deal with deepwater drilling riser operation in high currents, typhoons and cold fronts offshore Japan.

Offshore drilling operations are by nature more complex and challenging than onshore. Add in typhoons, cold fronts, and high currents, and the challenge is compounded.

In 2012 and 2013, JAMSTEC (Japan Agency for Marine-Earth Science and Technology) undertook the Integrated Ocean Drilling Program expeditions 338 and 348, respectively, in the Nankai Trough, a mega-earthquake site. The drill site, C0002, is 80km southeast of Japan's Kii peninsula, 1938m below mean sea level, in the Forearc basin.

Using the *Chikyu*, a dynamic positioning (DP) capable drillship, the target depth was 5200m below sea floor, where cores were taken and sensors installed to monitor and collect earthquake information.

Before reaching the target, however, the *Chikyu* had to contend with the Kuroshio current, which can vary daily, typhoons, and cold fronts. To mitigate these issues, JAMSTEC partnered with Houston-based Stress Engineering Services to optimize operations.

Kuroshio current

"The magnitude and depth of the Kuroshio current poses a number of problems for riser deployment, controlling flex joint angles while drilling and vortex induced vibration of the drilling riser system," says Kenneth Bhalla, principal at Stress Engineering Services.

At the site, the Kuroshio current not only changes speed throughout the day, but also direction, and has a non-uniform profile, meaning the current at the surface is much higher than near the sea floor.

For example, currents greater than 3.5 knots at the surface are typically reduced to 1 knot at 800m below mean seal level and to 0.5 knot at 600m below mean sea level.* These currents can have significant effect during riser deployment and retrieval, and blowout preventer (BOP)/lower marine riser package (LMRP) landing operations.

To cope with these factors, an offsite deployment procedure was adopted to deploy the risers, BOP and LMRP. Like the name suggests, an offsite deployment involves the deployment of equipment away from the high currents at the drill site, in a location with lower current. The equipment will then transit to the drill site.

For this operation, the *Chikyu* uses a method called drift on site, whereby the *Chikyu* deploys its equipment and drifts down current to the drill site. Using this method, however, puts the equipment at risk of running into shallow ridges or missing the drill site. As a result, detailed bathymetry charts were used to define the approach and evacuation routes, with remotely operated vehicles used to survey areas where clearance is less than 50m.

Another concern, due to the currents, is the change in angle of the flex joint; as the current increases, so does the angle. API RP 16Q address this issue and limits the flex joint angle to 2° during drilling mode when surface currents exceeds 3 knots. However, operations were allowed to continue if the current exceeded 3 knots as long as the angle remained 2° or less. Thus, tensioners attached to telescopic joints were utilized to help absorb some of the bending stress caused by the currents, managing the effects of high currents and sea state and allowed drilling operations to continue.

A further issue induced by high currents is fatigue damage to the riser caused by vortex induced vibration (VIV). To address VIV, fairings are used to mitigate the effects, though the fairings are only implemented on the top sections of the riser which will face higher current due to time constraints.

Additionally, to prevent equipment damage and alleviate VIV concerns, operations are restricted to currents traveling 2.5 knots or less. Accordingly, the currents are monitored using two acoustic current doppler profiler (ADCP) equipped supply boats at the drill site and 5mi southwest of the *Chikyu*.

Typhoons and cold fronts

With drilling occurring between autumn and winter, operations can be affected by cold fronts and seasonal typhoons.

"Typhoons and cold fronts can develop quickly at this location and cause the vessel to be "pushed off" location, thus halting all drilling operations," Bhalla says.

Cold fronts, which usually occur from November-January, can cause strong wind gusts, and sudden changes in direction causing significantly more drag.

The drilling riser deployment from the *Chikyu* drillship.

thereby forcing the ship out of position.

The procedure in such cases is to first direct the vessel heading to face southwest by south-southwest, to respond to the strong winds that come from the south and the high currents flowing from the west-east direction. However, once the direction of the wind changes to northwest by north-northwest, drag forces increase significantly, causing the vessel to lose position and drift. To prepare for this, the drilling assembly is raised above the BOP, the blind shear rams are closed, the riser displaced to sea water, and emergency disconnect sequences (EDS) are enabled to disconnect the LMRP from the BOP. Also, a rubber joint is installed to prevent damage caused by the intermediate flex joint contacting the keel during the force off.

The *Chikyu* drillship.

With a narrow operational window, the expeditions need to spend as much time being productive as possible. Specific operational criteria were established for dealing with the cold fronts, which are dependent on forecasted conditions. When wind gusts are forecasted to be more than 18m/s, the operations are put on standby, whereby drilling operations stop, and the bit is pulled back above the BOP. When winds gusts are forecasted above 28m/s, or if the current exceeds 5 knots following the passage of the cold front, disconnection is planned.

Additionally, controlling the vessel in high winds and currents is also challenging. So the DP operators prepare for these force off situations on simulators for position recovery and maintaining speeds below 2 knots to minimize VIV and the risk of the riser contacting the keel.

Typhoons, which usually occur from July-October, can produce wind gusts as high as 60 m/s which can affect DP controls. As a result, when a typhoon is forecasted within 200mi from the site, EDS is enabled, disconnection and riser retrieval is planned, and the site is evacuated.

However, all typhoons are not dealt with the same way. The procedure for disconnection and riser retrieval is a lengthy process that requires 3.5 days for full evacuation. So, for small typhoons, which can reach the site within four days of forming, a hard hang-off with the riser, can be performed, whereby the riser is effectively locked into the drill floor rather than a full riser retrieval. The benefit to this procedure is the rig time saved deploying and retrieving the riser. Though the risk involves momentary compression near the top of the riser, shock loading on the equipment when tension is restored, and the riser hitting the keel. Large typhoons on the other hand, can take 6-10 days to reach the site, allowing enough time for full retrieval. The decision for which option to deploy is dependent on the sea state conditions.

For both cold front and typhoon scenarios, forecasting plays an important role in decision making and operational safety. As a result, special typhoon information services, weather forecasting services, and regularly scheduled meetings with weather information providers are necessary.

Execution

During the 2012 and 2013 expeditions, the initial drill-on site deployment of the risers was successfully executed. With surface current at 3.5-4 knots, the *Chikyu* deployed the riser 10-15mi up current from the drill site, maintained vessel speed between 0.8-1.0 knots. The following BOP deployment and the 2013 LMRP deployment were similarly successful. VIV fatigue was kept low using the fairings and tensioners with 0.15% damage in 2012, and 0.25% in 2013. In total, VIV fatigue damage was kept down to 1.5% for the entire riser assembly in 2012.

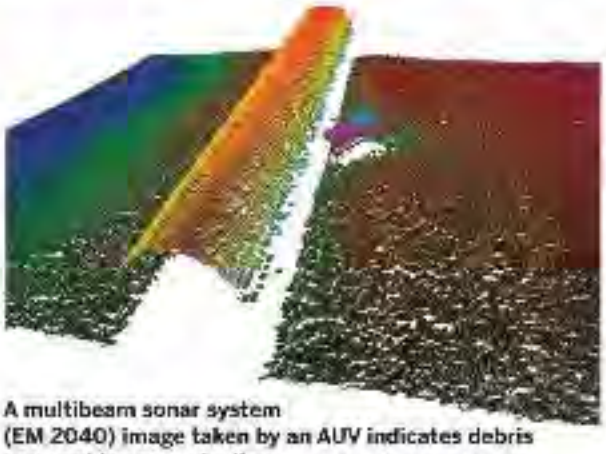
Cold fronts and typhoons were also successfully dealt with utilizing the prescribed procedures. A typhoon and a cold front each required a planned EDS, while another cold front caused a forced EDS, though all three were deemed successful.

In spite of the harsh environments and the unique set of challenges presented by the NT3-01 site, the drillship *Chikyu* was able to successfully execute the planned drilling activities with minimal downtime. **OE**

(This article is based on the 2014 Offshore Technology Conference paper "Planning and Feedback for Deepwater Drilling Riser Operation in High Currents, Typhoons and Cold Front" J. Sarohashi, T., Sawada, I., Kyo, M., Miyazaki, E., Yamazaki, Y., Yokoyama, T., Rhalla, K., Stafil, M.J., Gurpatye, A., Han, Y., Gong, L. (2014, May 5). Planning and Feedback for Deepwater Drilling Riser Operation in High Currents, Typhoons and Cold Front. Offshore Technology Conference. doi:10.4043/25182-MS

For AUV eyes only

Heather Saucier investigates how wireless technologies used by AUVs can make sea-bottom surveillance more cost-effective and time-efficient.



A multibeam sonar system (EM 2040) image taken by an AUV indicates debris encroaching on a pipeline. Image by Kongsberg Maritime.

A close-up photo shows the debris imaged above taken by an AUV.

Initially developed in the 1950s to study diffusion, acoustic transmission and submarine wakes, autonomous underwater vehicles (AUVs) have made their way into the oil and gas industry and, some say, are on the verge of reaching game-changing status.

Primarily used for detailed hydrographic surveys, pipeline and seismic array inspections, and environmental monitoring in both shallow and deep waters, AUVs are slowly replacing the need for surface vessels and, in some cases, remotely operated vehicles (ROVs).

While new technology is often eclipsed by the tried and true, especially during times of economic distress, those on both the sales and consumer sides of AUV technology insist that the vehicles can trim costs substantially by covering vast amounts of subsea terrain in one-fourth the time of traditional surface vessels.

"New technology is always daunting to clients," says Simon Goldsworthy, EURA Sales and Marketing manager of the United Kingdom-based UTEC NDS Survey, which often employs AUVs for its clients in the petroleum industry. "However, the use of AUVs is picking up momentum. AUVs have proven themselves in a variety of oilfield markets, and clients are looking at them as a game-changer for reducing vessel hours or even days on site."

Anatomy of an AUV

While many types of AUVs exist, they all operate without a person on board. Like an ROV; however, an AUV is independent, unlike an ROV, with no cables connecting back to a vessel, thus the AUV relies on navigation software that allows users to choose how it will perform pre-programmed tasks.

Equipped with a multitude of sensors including compasses, synthetic aperture sonar and "sniffers," AUVs can conduct precise ocean-floor surveys in the place of less effective bathymetric surveys, as well as detect the presence of oil plumes and other chemicals that could threaten the environment, says Arnt-Helge Olsen, vice president of Subsea Sales for Kongsberg Maritime, which is the manufacturer of some of the largest AUVs – the Hugin, Manin and Remus – which can reach depths up to 6000m, travel as fast as 6 knots, and operate in arctic and tropical waters.

Using wireless technology to communicate, AUVs provide better data because they use high frequency sonar and can get ultra close to ocean floor – their sensors relatively undisturbed by rough currents.

Most AUVs are battery powered, and most use propeller-based thrusters to move, while buoyancy engine-driven underwater gliders can operate for a year and cross oceans.

Small AUVS can be launched off a beach, while larger units are housed in landers on the seafloor, Olsen says, adding that they are primarily used in North Sea, Gulf of Mexico and offshore Brazil.

Array of uses

When performing site surveys after decommissioning a rig in shallow water in the US, traditionally the trawl method has been used to ensure proper clean-up. Vessels drag nets to catch remnants, and boat captains record items removed from the seafloor.

This type of operation can take multiple days and the cost is more than US$10,000 for each site, says Tim Taylor, CEO and president of Tiburon Subsea, which rents AUVs to companies to perform the same task.

"However, with an AUV, we can survey 8-10 sites in the same amount of time and cut the cost by half," Taylor says, whose company ships the 90-pound vehicles to clients with pre-trained operators. "And the imagery and data is so much more advanced. We have a full mosaic map of the area and

exact GPS geo-referenced data on it."

Routine pipeline and seismic array inspections benefit from AUVs as well. The vehicles can survey the ocean floor for threatening obstacles prior to the laying of pipelines and seismic arrays. They also can detect corrosion or damaged pipelines from seabed slides, as well as seismic arrays that have damaged nodes or that are entangled with adjacent arrays.

Calling AUVs a "force multiplier," Arnar Steingrimsson of Teledyne Marine, which manufactures low-logistic AUVs that are both propeller driven [the Gavia] and equipped with buoyancy engines [the Slocum G2 Glider], explains that one small surface vessel can launch multiple AUVs that each perform specific tasks – cutting costs tremendously by eliminating the need for a large surface vessel, tow spread or ROV.

Men prepare a HUGIN AUV for its next mission in the North Sea.

AUVs are ideal for platform area surveys, as they can encroach within the 500m exclusion zone without stopping production, Goldsworthy says. FALVs also have successfully performed scouring surveys between platform jacket legs.

Furthermore, some AUVs, such as the Hugin, can retrieve data – such as currents, temperatures, salinity, mammal life and even oil seeps, methane and carbon dioxide – by performing full water column dives.

"If you have a rig in an area with high currents, it could affect rig operations," Steingrimsson says. "Furthermore, if hydrocarbons are detected in the water column, that's an indication of a possible leak that you would have difficulty detecting from the surface. This enables you to detect problems in advance and greatly mitigate risk."

Traditionally, when collecting sonar data from deep-tow or remotely operated towed vehicles in 4000-5000m water depth, roughly 8km of cable is needed, requiring days of work from a surface vessel, Olsen says. "It takes hours for a boat to turn around as opposed to minutes," he says of an AUV's capabilities. "There are no cables. All the sensors are on board."

In the future, AUVs will be able to lay seismic arrays as well, Olsen says. "We are working to develop a seismic node that will swim out and deploy on the seabed," he says. "The AUV seismic nodes would be lowered in a sub-sea cage to the seafloor and swim out to the proper place. They would no longer be lowered from the surface. But this function will take years to fully mature."

(Editor's note: See "Making nodes fly" on page 42 of this issue for more information about flying nodes.)

In the meantime

Roughly 10 companies sell AUVs on the international market, and Taylor believes more are in demand.

"It's a busy ocean and it's getting crowded down there," he says. "You've got to have eyes down there, and these AUVs are the eyes."

And, don't forget about the No. 1 force fought by the industry: the weather.

A HUGIN AUV is prepared for launch in the North Sea.

"The North Sea is the perfect example. One-hundred percent of the days in the winter are unusable," Taylor says. "So get as much done in the summer as possible. Launch four vehicles and get four times the data." OE

A single node, nose on.
Images from Autonomous Robotics Ltd

Making nodes fly

The job of placing ocean bottom nodes for seismic acquisition could be set for a revolution. Elaine Maslin looks at Autonomous Robotics Limited's concept.

Imagine a scenario where you do not need to individually deploy ocean bottom nodes (OBN) for seismic surveys using remotely operated vehicles (ROVs). Instead, they fly and accurately land themselves on the seabed, autonomously.

It's an attractive idea, especially when you are talking about deploying hundreds or thousands at a time in deepwater offshore the likes of the Gulf of Mexico, Brazil or West Africa. It's also not that far-fetched. Autonomous Robotics Limited (ARL), a subsidiary of Thalassa Holdings, has been working hard on the idea since 2013, after buying GoScience, a technology company which had developed its own concept for flying nodes. The firm is now presenting the concept.

Acoustic positioning concept.

Put simply, the concept is a fleet of autonomous underwater vehicles (AUVs) operating as OBNs, which ARL call "flying nodes." Stored on the deck of a vessel in racks, they are deployed in groups of 72 via a cage, which is lowered into the water using an onboard launch and recovery system. Each exits the cage in turn under its own propulsion then flies to its pre-programmed position on the seabed. Once their work is done, and they're given a signal, each flies back up, back into the cage, before being stored back on deck where data is downloaded and they are recharged.

"Each flying node is effectively a combined AUV and OBN," says Dave Grant, ARL's CEO, and former managing director at SAAB Seaeye. The company has used, where possible, already tried and tested technology, or a minor variant of it, such as using ultra-short baseline (USBL) positioning and lithium ion batteries, although battery technology is fast improving and changing, so these could well change and continue to change, Grant says.

According to simulation work performed by ARL, deployment speed using the firm's flying nodes would be far greater than ROV-placed nodes, with some 1200 able to be deployed in one day, compared to 50-80 a day using an ROV. "This is more than an order of magnitude greater," Grant says. "Even with the automation coming into ROVs today, it would not be much faster and ROVs are currently the only option for deep water OBNs at the moment. What is holding ROV-placed nodes back isn't the quality of the data, it is the cost, which is excessive. If we are able to reduce the survey cost of deepwater ocean bottom nodes compared with ROV placed nodes there will be a major justification for this solution."

If you were surveying a 96sq km area, with nodes placed every 200 x 200m, with one node vessel and one source vessel, the costs would be 20% cheaper than using an ROV-deployed system, Grant says. If you go to the next stage and have two source vessels and one node vessel, you could save 66%, he says, by being able to shoot the survey faster.

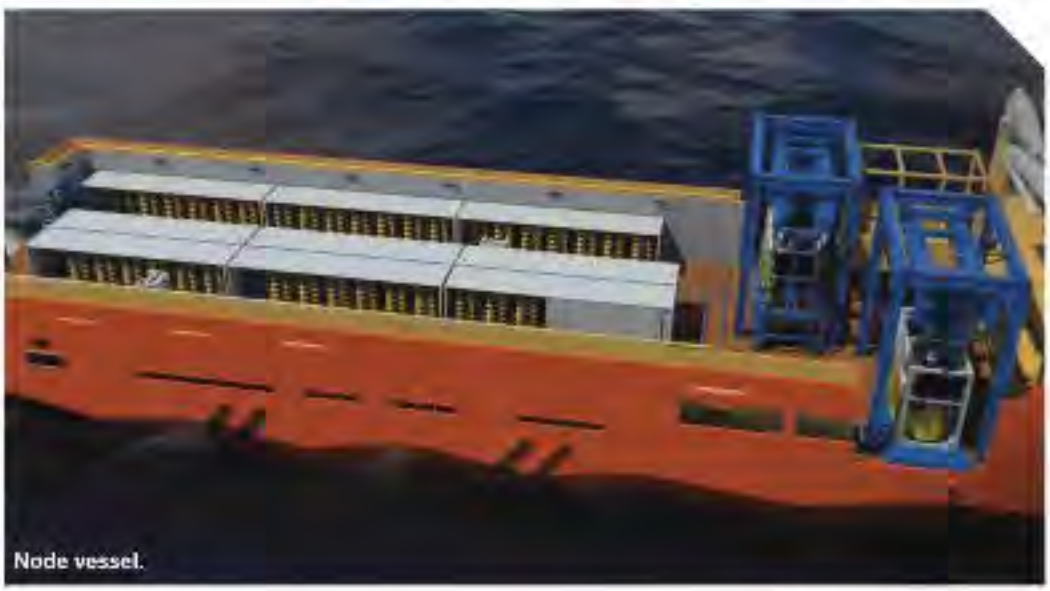
While ARL bought GoScience's IP, it has pretty much started from scratch with the concept. GoScience had been developing a "ring wing" autonomous underwater vehicle (AUV), Grant says, and it wasn't a configuration ARL thought would work for OBN seismic. ARL has looked at the challenge, taking into consideration cost of manufacture, and ability to handle high numbers from one vessel.

What they have come up with are more rounded, disc-shaped AUVs. The shape was chosen both for ease of handling and storage on deck and in the deployment cage, but also to lower drag as it travels through the water.

For navigation, established USBL underwater positioning systems, using acoustic signals, used on vessels today for guiding ACVs and ROVs has been used. But, for its flying nodes, ARL uses two USBL systems, one on the node vessel and a second on an unmanned surface vessel – another technology, which, while new to the oil and gas industry, is established in the defense and environmental monitoring space.

"Using two is necessary to accurately position the node on the sea bed," Grant says. "As the vessel is moving, by the time the node is on the sea bed you

Nodes in containers.



Node vessel.

Cage being deployed.

Node recovery into cage.

wouldn't be able to accurately position it. The accuracy will be equivalent to ROV-placed nodes."

For power, the firm is currently looking at lithium ion batteries, but this may change. "We are looking at a number of new technologies and the battery technologies used will likely change as we go forward as technology improves. But, it's just a battery pack and battery management at the end of the day," Grant says.

The flying nodes have been designed to work down to 3000m. While ARL isn't revealing the unit's power consumption, Grant says in a 60-day deployment at 3000m, about half the battery power would be used on the seabed, with the rest used to descend and return the node to its cage. In shallower waters, they would of course use less power during deployment, which means they could be left for longer, Grant says.

With deep ocean bottom currents mostly less than half a knot, or even a quarter of a knot, there is not much to deal with in terms of disturbance on the seabed, he says. However, ARL would measure the current profile through the water column and on the seabed before deployment in order to develop a deployment plan.

And this is where the flying nodes get interesting. ARL has developed the flying nodes to have variable buoyancy, which will aid their descent as well as how they rest on the seabed, with a mixture of pre-programmed and live control via acoustic communications.

"The nodes will have neutral buoyancy when they are deployed to 20-30m beneath the vessel," Grant says. "When we want them to descend we can change the mass distribution and they fly down to the seabed at about 60°. Near the seabed, the mass distribution is again changed so they descend vertically to the seabed. On the seabed they are heavy to give the pressure needed between the coupling plate (a type of metal castellated plate on the OBN's base) and the seabed to be able to give a good coupling to transmit the sounds waves in to the OBN's sensors." The rounded disc-shape also means each unit has a uniform weight distribution around the center of the sensor plate, which helps the coupling. Most of these features, the variable buoyancy and mass distribution are pre-programmed before deployment, but, certain features during the operation will be controlled, so a low data rate, bi-directional system has been built in to the USBL system, between the node and the node vessel, so there is status information and you can send control information back to the node when necessary. The USBL system has also been adapted, because of the high numbers of nodes being deployed.

"It is quite a challenge trying to fit all these features and capability in to a volume about 580mm diameter and 280mm high," Grant says. "And we want to get this down another few millimeters."

So far most of the design work has been based on studies and simulation, as well as work with technology suppliers, such as the USBL system. But, the company is moving towards the end of concept stage and hopes to get the first prototype node, which will initially be tethered, into the water in Q1 2016. "We expect to go into detailed design some time in 2016," Grant says. OE

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Every barrel (now) matters

A relentless focus is required to maintain and optimize production on often aging North Sea assets. Elaine Maslin reports.

Optimizing production and increasing efficiency is rising on the agenda in a low oil price world, not least in the North Sea.

It needs to. On the UK Continental Shelf (UKCS), production efficiency, a metric of how much production facilities produce compared to how much they could produce, fell year on year since 2000, dropping from 80% to 60% in 2012. At the same time, costs increased – by 8% year on year since 2000 – and staffing levels have increased, by 9% in terms of staff per barrel produced, according to figures from consultancy McKinsey & Co.

The good news is that, under pressure from sub-US$50/bbl and even sub-$30/bbl oil prices, there are signs the industry is starting to get a grip. Production efficiency looks set to be closer to 70% in 2015, according to the UK Oil and Gas Authority's exploration and production director Gunther Newcombe, speaking at trade body Oil & Gas UK's Aberdeen breakfast briefing early December.

What's surprising, McKinsey suggests, is that production efficiency is not necessarily directly correlated to spending.

"What's worrying is that the increase in production losses on the UKCS has mirrored the increase in costs, i.e. although opex spending increased – from €150-400 million [US$217-581 million] – production efficiency didn't improve," McKinsey

Wintershall's Brage platform.
Photo from Wintershall

analyst Dan Cole says. McKinsey has looked into the causes behind the fall in production efficiency, using its global offshore benchmark that is based on a database of more than 300 fields on which operators have provided data around production, costs and safety. According to the data, the cost increase breaks down to about 20% due to increased activity, 40-50% due to increased input costs, and then 30-40% due to greater inefficiency.

Plant failures

Cole, who was speaking at Offshore Network's Production Optimization conference in Aberdeen late last year, says a large part of the inefficiency on the UKCS has been due to plant failures, but also export losses, through third-party infrastructure shutdowns. In Norway, the issue has been reservoir-based, due to problems such as scale build-up in wells, sand production, and water injection issues, Cole says. When McKinsey tried to look at the data to find relationships between spending levels and reliability, there were no obvious links. "We tracked facilities over time," Cole says. "One reduced costs and efficiency fell. Another maintained higher efficiency, but costs increased. The interesting assets are those maintaining efficiency, but also reducing costs."

One trend that was seen was that those assets with the lowest cost increases had some of the highest production efficiency.

McKinsey then compared two assets of similar size, age, and capacity, one from the top quartile of performers, to see what they were doing differently. On one, A, production efficiency and costs had been maintained, on the other, B, it had gone down.

Cole explains that A's production efficiency was consistent, with loss tracking embedded into the organization. This meant reliability experts from outside the industry were brought in. Additionally, there was a huge focus on cost. "Everyone knew the numbers," Cole says. "They also put senior operations guys into the supply chain to have a much more positive relationship with the supply chain.

"Those things were largely absent on the other asset," Cole explains. "What drives good performance is not age, operator size or type, its operator practices being embedded into the operation.

"[On A, the operator had] removed barriers, gave freedom to operators to get ideas out. This helped debottleneck and saw a 12% production increase, taking them from 80,000-85,000 b/d since crisis, with half of that implemented in three months."

Identifying the "stars" in the organization also helps, Cole says. McKinsey looked at the relationship between production and shifts and found one operator, whenever he was on the platform, caused a 5-8% increase in

Wintershall's Brage platform.

production, a figure that was higher when compared to the worst performing team.

"He reset the platform, tuned it," Cole says. "We should use these guys. What are they doing and why is this not shared? How do you capture this?"

In this instance, when asked to share what he did, the operator, who was close to retirement, said he didn't want to embarrass the other team, which also raises the issue of how you embed knowledge into an organization as people leave.

When it comes to it, "The best performers have a high focus on data and quality management," Cole says.

Improving uptime

Duncan MacFarlane, a production technologist at Maersk Oil, based in Aberdeen, has been looking into production efficiency on a floating production unit (FPU), which is being decommissioned. His work first looked at industry best practice, and then how this compared to what was happening on the FPU, which had been on station in the UK North Sea for nearly 20 years. The idea was to see, if it was redeployed, how production efficiency could be improved, while minimizing capital spending.

According to best practice literature, "efficiency should be driven from all levels of the company. Organizational change is key to improving efficiency," MacFarlane says. Best in class prepared for high impact low frequency events and understood their losses. Other ways to improve production efficiency were benchmarking through industry events and bodies such as the Production Efficiency Task Force, as well as effective communication, monitoring key performance indicators, and using digital oilfield technologies - such as real time data optimization, condition based monitoring, for preventative rather than reactive maintenance.

Armed with a view on how it should be done, MacFarlane looked at losses and costs on the FPU between 2008 and 2014, as well as uptime compared to the wider industry and company strategy.

The unit had failed to meet its target operational efficiency – both its own KPI and the industry target of 80%, MacFarlane says. The top two major planned and export production loss events, amounting to more than three days of lost production, were third-party export infrastructure outages. Other major production loss events were a subsea skid installation and some well intervention work. These together amounted to 16.1 days of planned losses a year.

By far the greatest influence on production losses were major losses that were not planned or export-influenced, amounting to 53 days per year. Integrity was the leading root cause of failures, with 55% of integrity issues associated with minor losses due to hydrocarbon weeps or leaks, followed by "human error."

Some 22% of all production efficiency losses were minor losses, mostly caused by compressor and turbine failures, with unknown roots causes. Gas compressors accounted for the greatest amount of downtime and controlled shut downs, but also trips. Turbines were responsible for the greatest amount of downtime associated with delayed start-up.

But, something of a concern – and an opportunity – was that 59% of root causes of minor losses were unknown. "There was no record and that's a key area of work for the future," MacFarlane says.

Interestingly, MacFarlane found that the number of trips per month looked correlated with harsher weather windows. "As wave and wind increased, trip frequency increased," he says. Temperature didn't seem to effect performance, but more work would need to be done in this area.

Concluding, MacFarlane says that it looked like learnings were not passed on. The maintenance strategy was reviewed and while it set out to be best in class, and replicated the literature, there were no procedures, work flow or process flow to follow it. It was just written down, he said. Echoing Cole's comments, culture and organizational structure would need to adapt if change was to happen in this area, MacFarlane says.

Reviving an aging asset

Wintershall has been putting production efficiency at the top of its agenda on the Brage platform offshore Nor-

Voices

What can companies do to become more efficient in this lower-for-longer market?

Standardization has been discussed in our industry for some time and is a critical component of efficient business processes and optimized operations. The opportunities and advantages are well-understood, with progress seen recently in the subsea sector across operators – for example, a joint industry project (JIP) on materials and welding. The driving benefits are cost and lead-time reduction, with enhanced quality and reliability through re-use of existing parts and sub-systems while maintaining field-specific requirements. Further, well-defined interfaces through system designs enable better management of risk through repeat manufacturing, assembly and installation, with a more predictable execution pattern. As we evolve from a market reliant on bespoke design to one that more gradually embraces standardization and modularization, we can see fundamental process change throughout the industry.

Federico Noera, Subsea Systems & Drilling Global Engineering GM, GE Oil & Gas

In the current challenging market, service companies need to focus on aligning their costs with projected revenues, in order to maintain a competitive position for when the market returns to full strength. However, companies need to ensure that they do not cut corners; cost cutting should not in any way jeopardize the safety of their personnel or the wider environment. Pricing of services should also be a significant consideration for these companies. While it is important to keep prices competitive, it is vital not to be tempted into discounting equipment and services too dramatically, as some level of profitability needs to be sustained in order to maintain a high level of service. Despite the obvious appeal to companies looking for a quick way to stimulate cash flow, lowering rates to secure business is neither sustainable nor helpful to the industry in the long term. Above all, it is critical for companies to focus on sustaining credibility with their customers and vendors.

Kirby Arceneaux, chairman of Wellsite Fishing & Rental Services

way, in this case, as the new owner of an old asset. Brage had been due to cease production in 2015, but after being bought by Wintershall in 2013, it is now due to continue producing until around 2030. The field started production in 1993 under Hydro, and was operated by Statoil from 2009-2013.

After taking over the asset, the focus was on improving health, safety and the environment, production efficiency, cost and volume. Wintershall increased production efficiency in 2015, while opex costs were cut from NOK1.3 billion ($146 million) in 2014 to about NOK 950 million ($106 million) for 2015.

"Is it a revolution? No, it's just hard work," says Alv Bjorn Solheim, technical director and deputy managing director, Wintershall, speaking at the Production Optimization event. "When you look at the efficiency plot for 2015, we have improved efficiency from 80% to 94% and we are on 95% now. It has been a huge amount of work, including by the people offshore. We have not done any particular thing. We have done a lot of small things." The team also looked at what the "A team" was doing to increase production, some times more than 10% compared to the other shift, then shared this.

"For me, it is about focus," Solheim says. "When you go offshore, we are talking to people about this and that it's very important. We are telling them every barrel counts. It is a great achievement and giving us volume and income in quite a difficult year."

But, Solheim wants to do even more with Brage. "The next step is to work on infill drilling," he says. "We put on stream one well in June which gave us 6-7000bbl and still does. We are now at around 20,000 boe/d [in total on Brage]. We have close management on the cost of wells and a cost focus on modifications. The cost of wells is crucial. If we are going to survive on Brage until 2030, we need new wells every year until 2025. We are sitting on four reservoirs but we need to reduce the cost by 40% if we are going to survive. So that's a challenge and we are working on it."

Wintershall also changed its contracting structure, with maintenance and modifications no longer bundled into one contract to a single external contractor. Work has been taken in house and then contracts issued on a call off basis, Solheim says. OE

FURTHER READING

Read more – 900 MMboe lost through low production efficiency http://ow.ly/X71Wm

Breaking ground on Butch

Open water coiled tubing drilling has been used offshore Norway in an industry first. Elaine Maslin found out more.

Coiled tubing drilling (CTD) isn't a new concept. But, it is one that has struggled to gain traction, not least offshore.

The attraction to CTD, which has been used onshore since renewed interest in the technology in the 1990s, is that it could enable continuous drilling – you don't need to connect drill pipe – reducing handling and increasing safety, as well as offering continuous hard-wired telemetry down hole. Being able to continuously drill and pump also enables underbalanced drilling operations to be performed and the smaller footprint means that it can be deployed from smaller vessels, instead of requiring a full blown rig.

The downsides are that because you cannot rotate the pipe, drilling depths could be limited and it's not so easy to circulate out cuttings. The entire tubing string also becomes a single consumable, instead of being able to recut or surface individual connections in rotary drill pipes.

For Centrica, which believes it was the first oil and gas operator to use open water CTD offshore last year, from a light well intervention vessel, the technique was an ideal solution and one with further future potential.

Centrica wanted to drill a pilot hole, as part of pre-development drilling work on Butch subsea tieback project in the Norwegian sector of the North Sea. The pilot hole was needed to test for shallow gas deposits at the planned drilled center location for the Butch field. Using a CTD spread on a light well intervention vessel meant the firm didn't have to use a rotary drilling rig, likely on a semi-submersible.

Butch

The Butch field was discovered in 2011, in the Norwegian part of the North Sea, about 13km east of the Ula field. Recoverable reserves are estimated to be between 27-61 MMboe. The development concept is a subsea tieback to the BP-operated Ula platform, with a final

Island Offshore's *Island Constructor*. Image from Centrica Norge

investment decision expected late this year (2016). First oil is planned for 2018, with a peak production of about 35,000 boe/d.


Espen Kopperud

"If we hadn't checked for shallow gas and started doing development work three years from now, and we placed subsea infrastructure and had a jackup here, and then had shallow gas, we would have had to move the infrastructure and the rig etc.," says Espen Kopperud, project manager at Centrica Norway. "We could save several hundred million Norwegian Krone avoiding that scenario."

Centrica looked at using a semisubmersible, but with higher day rates, despite lower prices in the current environment, the total project cost worked out at about 30-50% lower, Kopperud says. The flexibility of the coiled tubing string has an added benefit that a well kill operation can be performed via the coiled tubing with the vessel at a distance, in the event of a blowout. "This is new, we don't have option to do this with semisubmersible," Kopperud says.

The subsea injector and ROV in operation

Island Offshore and Baker Hughes, which worked for Centrica on the Butch pilot hole, have used the technique offshore Norway already, just not in oil and gas. In 2014, the pair used the technique to take core samples from areas around Rogaland County, where road tunnels were due to be built underneath fjords as part of the Ryfast project.

"We more or less made a few small tweaks [to the system they had developed] and added another layer of operation specific procedures and assurance to be able to drill on the Butch location in the North Sea," Kopperud says. "The main difference was the unconsolidated sands and clay formations we had to drill through. Ryfast had hard rock. So we had to optimize the drilling method around avoiding wellbore collapse and stuck pipe prevention. Apart from that, the main difference was that we had a chance of hitting shallow gas."

For this eventuality, the team did "a lot of contingency planning. We were the first ones to do this and as part of oil and gas regulations in Norway, we had to fulfil quite a bit to achieve regulatory approval of the new drilling method," Kopperud says. A lot of time was also


Well kill with vessel moved.

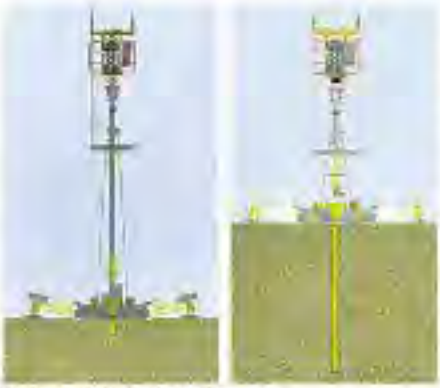
The subsea guide base

The ROV control room.

spent qualifying the method, which would involve spooling out the coil on the seabed, doing a dynamic kill and cutting the coil downhole.

With a mixed crew, comprising Island Offshore staff, who have done a lot of wire line work, and Baker Hughes staff, with coiled tubing experience, Centrica was conscious to do a lot of training around chain of command and to make sure the teams worked efficiently together.

For the operation, Island Offshore's *Island Constructor* was kitted out with a coiled tubing drilling unit, with 3100m-length of 2 7/8in coiled tube on a 4-5m tall coil tubing reel. Full system testing was carried out near Stavanger before the vessel sailed out to the Butch location, in 86m water depth. Once on site and positioned, the 50-60-tonne subsea guide base was lowered and positioned. A 15m lubricator pipe was then set up as a conductor to penetrate the sea bed in the center of the guide base.



Subsea lubricator diagram

The vessel's tower was then lined up above the lubricator, and the subsea injector was landed. The subsea injector, with electric and hydraulic controls and power supplied via the ROV, is installed on top of the lubricator.

The 6 ½in bit, rotating with a mud motor on the end of the coiled tubing, was then jetted down 8m into the seabed, before the lubricator is locked into place using an ROV. Then a 50m rat hole was drilled before pulling out of the hole then running back in with a 50m-long bottom hole assembly, comprising of mud motor, rotary steerable system, logging while drilling tools, and a 5 7/8in bit.

The challenge with CTD is around hole cleaning, to get solids and sediment out of well. But, procedures were designed to deal with this, Kopperud says. Drilling continued to 420m below the seabed and then the hole was circulated and logging carried out to find any shallow gas. There wasn't any so the hole was plugged with a 125m cement plug – more a precaution to avoid communication with future development wells, than a regulatory requirement.

"We pulled out of the hole, removed the lubricator and guide base, cleared the seabed, and sailed away. It had taken four days, six hours. That was really optimum with no issues," Kopperud says. "It was a good job, managed ahead of time and budget, with no issues. We have started and proved this method and it is now available to the industry."

But there could be more possibilities to use open water CTD. "Island Offshore also proved in 2014 that you can drill high inclination wells at really shallow formations," Kopperud says. "There are a few fields in the Barents Sea where that's a requirement, [with reservoirs] a few 100m below the seabed. With conventional drilling, horizontal wells in shallow reservoir zones could be very hard to achieve. . It's a challenge and CTD is more flexible. But you still need to be sure you can run casing. There needs to be a trade-off. Formations, sediment and hole stability also need to be managed with special procedures, because you don't have a spinning drill string to circulate them out. These are important to manage properly."

Industry has recognized the method developed by Baker Hughes and Island Offshore. In August 2015, Island Offshore received a technology award for this exact technology during the Deepwater Intervention Forum, presented by *OE*, in Galveston, Texas.

For Island Offshore, the aim is to use the same principle within light well intervention, plug and abandonment as well as other types of well intervention. **OE**

Tools of the trade

Weatherford's Alex Goodwin explains how a RFID circulation sub displaced seawater to facilitate a formation integrity test in the Gulf of Mexico.

A unique application of a drilling circulation sub enabled an operator in the Gulf of Mexico to perform a formation integrity test (FIT) on a casing shoe in a shut-in well. The well had been cased 17 years prior to the operation; however, upon drillout, a FIT indicated poor isolation between the 22in and 28in casing shoes. The operator installed two cement plugs, but opted to abandon rather than cement the well.

After 17 years, the operator had reason to believe that barite sag and formation collapse may have increased shoe integrity in the abandoned well. Because of the degree of uncertainty, however, they did not want to invest in a high-pressure wellhead housing (HPWHH) and riser. The operator therefore sought an alternative way to perform a FIT.

Weatherford proposed using an inflatable packer as a barrier to keep the well static during operations. To implement this unusual technique in an offshore well, Weatherford also needed a method to precisely spot fluids to control fluid dynamics during and after the test. Weatherford selected the JetStream RFID circulation sub, which is normally deployed during drilling operations, to manage fluid displacement.

The rig crew deployed the JetStream sub, set the inflatable packer, and completed the FIT test without incident. A drillpipe plug was then set above the packer and below the JetStream using wireline. The large, full bore of the JetStream sub made it possible to run wireline through the inside diameter (ID) of the sub and set the plug below the sub and above the packer.

The plug-packer combination served to protect the wellbore in two ways. First, the plug prevented drilling fluids from entering the area of the wellbore below the packer, which was extremely sensitive to pressure changes. An influx of fluids into this area could potentially fracture the formation and compromise the FIT test — thereby jeopardizing the main objective of the operation. Secondly, the packer helped to prevent seawater from entering the open hole. The presence of seawater in the open hole would have increased the risk of well-control issues, especially considering the shallow water flow in the field.

After setting the plug, the crew needed to activate the JetStream sub to displace seawater from the annulus to the drilling fluids above the packer. The JetStream sub is normally actuated using RFID tags, but in this case the plug would have prevented RFID tags from flowing through the tool. Instead, a Weatherford field specialist used pressure cycle activation — a method in which a series of pressure pulses are sent downhole in algorithm-determined intervals — to open the tool. The seawater was displaced from the annulus to above the sea floor. With the ports open, there was sufficient flow to pump down RFID tags and close the JetStream using RFID actuation.

Fluid dynamics were carefully monitored throughout the operation. After closing the JetStream sub, the team detected an underbalanced condition, which was remedied by re-opening the sub to displace additional fluids. Once balance was restored, the team closed the JetStream sub and retrieved the plug and packer using wireline.

As a result of this operation, the operator obtained reliable FIT data that confirmed the integrity of the casing shoe prior to investing in a HPWHH. With the integrity confirmed, the operator is proceeding with plans to continue drilling the well.

While it is unlikely that many operators will find themselves in this identical situation, the project showcases the level of operational flexibility that can be achieved using advanced downhole tools. The large, unobstructed ID of the JetStream sub, along with its ability to be reliably actuated via pressure cycle, made it well-suited to overcome the specific challenges presented by this job. OE

***Alex Goodwin** is the global business development manager for performance drilling tools at Weatherford. He is responsible for supporting technologies including the JetStream RFID circulation sub, the RipTide RFID drilling reamer, and Dolley jars in the US, Canada, and Trinidad. He holds a bachelor's degree and an MBA, both from Louisiana State University.*

The JetStream circulation sub can be activated using RFID tags or pressure cycles for added operational flexibility. Photo from Weatherford

Greg Hale and Dora Laine explain how digitizing information can help improve uptime, increase production and optimize resource utilization in the asset-intense industry oil and gas industry.

Automation: Extending assets' lifecycle

Heading into a year of lower profits projections, it would be easy to just batten down the hatches and wait until next year, when the price of oil could be on the rise.

Whether the price of oil increases, decreases or stays the same, the industry has to learn and embrace the idea of streamlining all processes and getting the most out its assets.

It is no surprise that 85% of oil and gas executives said that the overall cost of project ownership is the most important problem they will need to address in an effort to streamline how they execute capital projects. With over 200 mega projects in oil and gas and chemicals around the world, coupled with severe market volatility, executives are looking for solutions to manage intellectual information in a scalable environment. Engineering technologies will have to manage multi-asset globalized big data environments while offering domain capability. This combination of needs has been referred to as intelligence management or intelligence planning.

"People are trying to achieve more with less," said Tim Wenman, senior consultant, asset integrity at Shell Global Solutions International, in a report published by Shell. "When companies want to reduce costs (capex) they are often reluctant to invest in new equipment, so the focus has to be on extending the life of existing assets. But, if you don't do that properly, then you can experience loss of process containment and reliability will also suffer."

Ensuring a reliable operation, boosting efficiency and reducing unplanned downtime through improved asset management can help producers grow in a down market and will help increase margins when prices start rising.

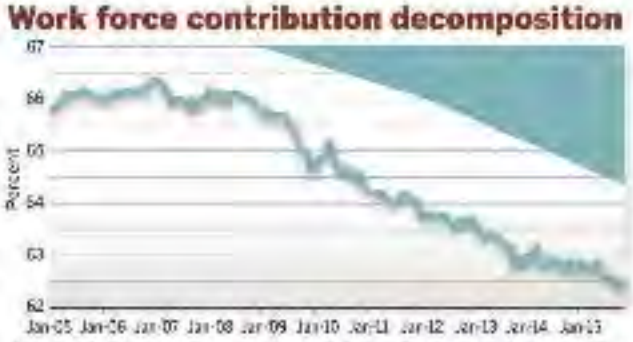
Multiple causes

The drivers for this intelligence technology include the continued volatility in oil prices, retiring knowledge, aging infrastructure, and increased regulatory and environmental scrutiny. Additionally, global volatility and changing energy sources including increased availability of petroleum through the onset of shale gas as well as more efficient forms of renewable energy is forcing oil producers to cut costs while stimulating downstream refiners and chemical companies to efficiently invest into the future.

In a joint IBM/Dassault Systèmes study of large oil and gas companies, executives categorized the challenges that have the most impact on their business. As total cost of ownership of oil and gas plants is generally greater than the initial capital outlay cost, executives said the most critical challenge was managing the overall asset lifecycle cost. This can occur via better access to up-to-date information throughout a plant's lifespan, which provides a sound foundation for decision-making.

There are more than 6700 platforms in operation around the world, at least 2000 of which have been in operation over 20 years, some way past their original design life. That means operators have to make sure an asset can

The most critical challenge was managing the overall asset lifecycle cost, executives said in a joint IBM/Dassault Systèmes study of large oil and gas companies.



Managing workforce dynamics was the second most important challenge to their business, executives said in the survey.

continue to perform its required function effectively, safely and productively.

In addition, industry averages show 5% of production capacity is lost each year due to unplanned downtime and in a down market those numbers can help keep a company in the black.

Aging out

After managing the overall asset lifecycle, 80% of executives in the survey said managing workforce dynamics was the second most important challenge to their business, such as retiring knowledge, operator training and the need to leverage global or remote resources. It remains vital to have access to information accumulated during projects and to make it available to personnel who need to know. This promotes continuity, increased skills, and helps makes the best use of the expertise and equipment available.

Just think, with Baby Boomers leaving and a dearth of younger engineers, it helps to have more automation to replace vacant desks, but it also helps to standardize and make sure everyone has the right training and understands the standard operating procedures.

The third top challenge, according to the survey, is the need for repeatability, which drives predictability in capital projects. Reusing proven methods and designs from past projects speeds new project delivery and reduces costs and risks. Once again, the key is easy access to, and reuse of, the right information.

Need for collaboration

To mitigate the challenges, stakeholders could benefit from technology that can improve access to information and to increase collaboration between internal and external workers. Technology-enhanced training solutions can improve the quality of information provided to operators and maintenance personnel. Technology can also play a key role in capitalizing intellectual property and corporate best practices as oil and gas plants' extended lifespans require the ability to "remember" every decision made and every solution implemented. Companies can benefit by digitally transforming their operations and using technology to standardize, simplify and streamline information access.

To move forward, operators need to focus on upgrading performance and boosting economic viability.

Oil and gas producers need to ask:

- How can the organization optimize production from assets with fewer personnel?
- How can the producer predict and prevent shut-ins and interventions caused by equipment failures and other abnormal conditions?
- How can critical data become available to key personnel in proper context in order to best use the skills of specialists to hike decision-making efficiency?

To drive digital transformation, companies need to focus on the ability to access decision-critical information in real time, engage in predictive and prescriptive maintenance, and streamline and automate workflows all with full traceability of intellectual capital throughout the plant lifecycle. This sustainability of a company's intellectual capital helps drive long-term growth and profitability even in the face of changing market conditions and employee turnover.

Companies can promote a culture of innovation by leveraging collaborative capabilities to harness project stakeholders' creative energies and insights using social media tools to exchange ideas and share expertise.

Workers from multiple organizations and functions can work together on the same digital representation of a facility to ensure optimum fit and interaction between their disciplines.

It only makes sense, better collaboration helps organizations efficiently manage projects and reduce late-stage errors. Simulation tools allow companies, for example, to leverage information from 3D digital subsurface models to increase production by developing more accurate drilling plans or to run fit-for-service simulations on existing plants to determine the fitness of critical equipment.

With advancements in technology, 3D and visualization allows companies to hike competence in training workers, as well as improve efficiency and operational safety.

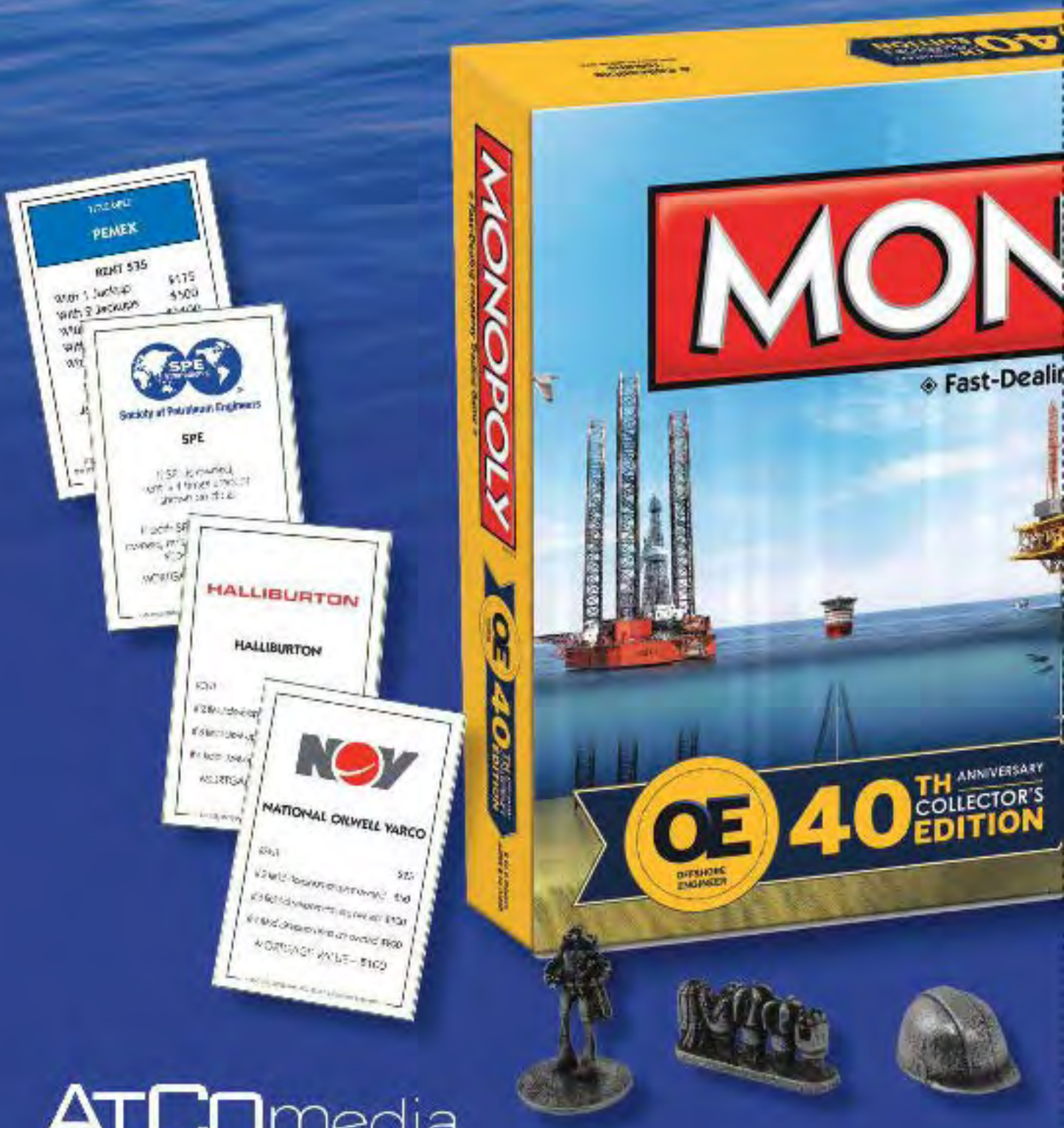
Producers will survive and maintain profitability by increasing production efficiency and cost savings. What will move producers to the next level is software and technology, which will call important information to increase production efficiency and cost savings.

Companies that capture and digitally model their information are on the right path to better enterprise intelligence planning. OE

***Gregory Hale** is the editor and founder of Industrial Safety and Security Source (ISSSource.com) and is the contributing automation editor at Offshore Engineer.*

***Dora Laine** is a freelance writer based in France.*

EXPERIENCE THE OIL LIKE YOU NEVER



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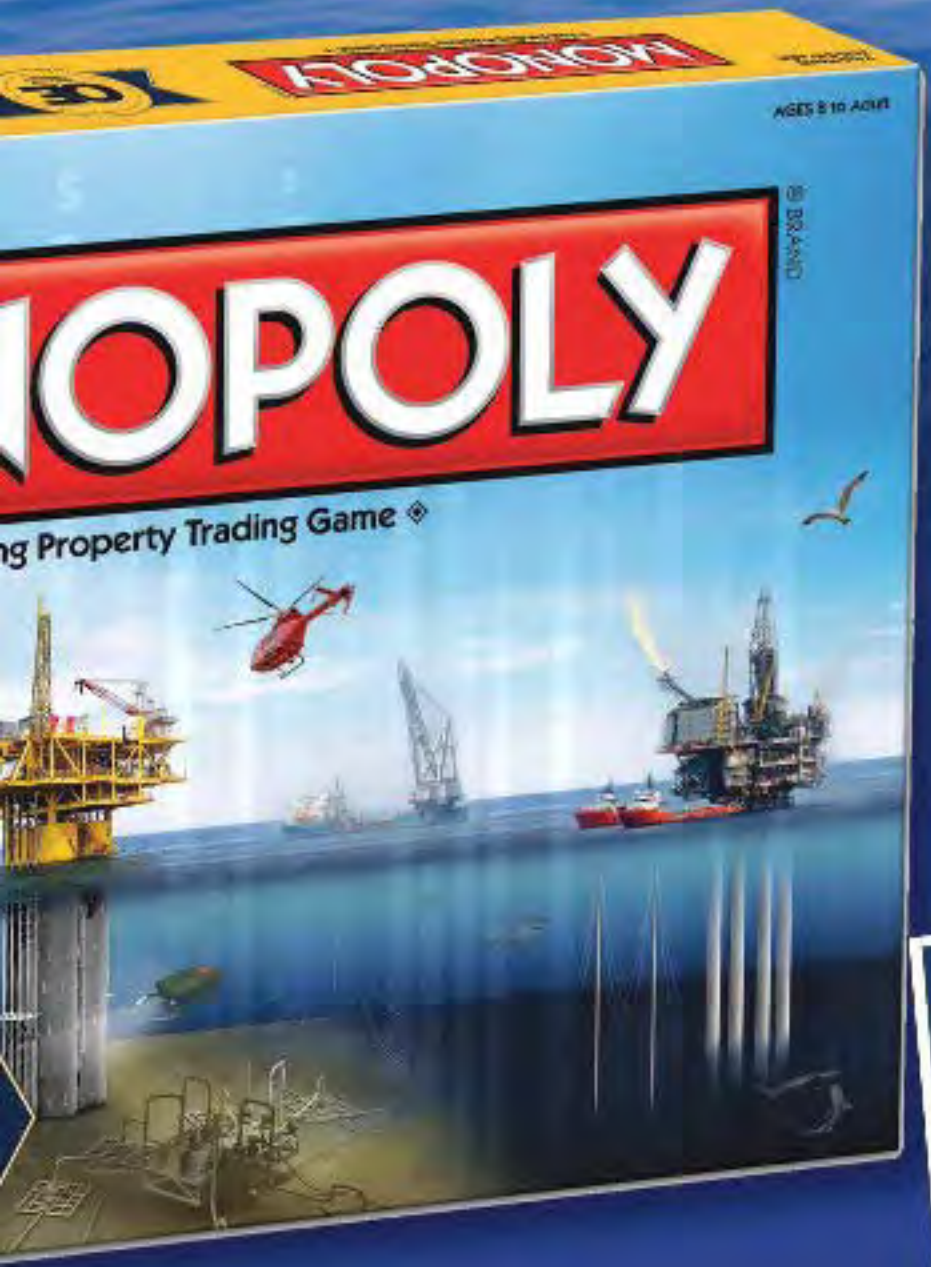

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Undeveloped Down Under

Australia and New Zealand hold vast petroleum potential, much of which remains undeveloped. Audrey Raj sets out the detail.

Samples of oil from various New Zealand discoveries. Photo from PEPANZ

While the Australian oil and gas sector was all about the development of existing gas resources in 2015, New Zealand wrapped up the year awarding nine exploration and production [E&P] licenses in its prolific Taranaki basin, comprising of six offshore and three onshore permits.

In its latest bidding round, OMV New Zealand was awarded four offshore permits and both Todd Exploration and Mont D'Or Resources bagged one offshore license each.

According to New Zealand's Energy and Resources Minister Simon Bridges, collectively the permits include a committed work program expenditure of about US$2.8 million [NZ$4.4 million], with the potential of more than $236 million (NZ$364 million) if all contingent work is realized.

"The result shows that the block offer approach is successfully attracting investment in New Zealand even in the face of low commodity prices, which are putting pressure on exploration companies to reduce expenditure," Bridges says.

"Over the past three years, the block offer process has successfully increased petroleum exploration investment. Block offer 2015 consolidates these gains and confirms what the industry already knows - that the potential for Taranaki is far from reached."

Separately, New Zealand also closed its 2016 block offer consultation in October last year, which includes one onshore and four offshore areas in the Taranaki, Pegasus and East Coast, Northland-Reinga and Great South and Canterbury basins. The block offer will be announced this March.

In 2015, Australia, too, offered 29 offshore blocks across eight basins for competitive bidding by prospective explorers, as part of it its annual Offshore Petroleum Exploration Acreage Release.

Located in the Northern Territory, the Territory of Ashmore and Cartier Islands, Western Australia, South Australia, Victoria and Tasmania, basins such as Bonaparte, Browse, Rochuck, Carnarvon, Ceduna, Otway, Sorell and Gippsland made the list.

Out of the 29, 23 areas were made available for work program bidding and six areas for cash bidding. While round one of work program bidding closed last year, tendering for cash bidding closes in February 2016, followed by the second work program bidding due in April this year.

The provisional areas for the 2016 Offshore Exploration Petroleum Acreage Release will be available early 2016 and the final areas will be announced in June at the Australian Petroleum Production and Exploration Association (APPEA) Conference in Brisbane.

Liquefied natural gas (LNG) has also been a hot topic for Australia, with the ramp up in LNG production. According to APPEA, record investment in LNG development is helping to sustain Australia's economic growth, and natural gas output will be more than double in the next five years.

Furthermore, over the same period, LNG exports are expected to increase from 26 MTPA to more than 76 MTPA. The Australian oil and gas industry remains a major contributor to its economy, perhaps even accounting for one-third of Australian business investment.

Similarly, New Zealand's oil and gas sector is also a significant contributor to its own economy. The government receives approximately 42% of the operating profit of a development through a combination of royalties, levies and taxes, according to the New Zealand Petroleum and Minerals.

Explorers in Australia, New Zealand

AWE Ltd., Bass Strait Oil, Quadrant Energy, Beach Petroleum, BHP Billiton, Chevron, Cue Energy, ExxonMobil, INPEX,

Queensland Curtis LNG (QCLNG) terminal. Photo from BG Group.

Metgasco, Origin Energy, BG Group, ROC Oil, Cooper Energy, Santos, Shell, Strike Energy, Tap Oil, Woodside Petroleum and Total are some of the local and international names with footprints in Australian E&P.

Shell's upstream business in Australia is based in Perth and it employs over 500 staff. Its major gas developments include the Prelude Floating LNG, North West Shelf, Gorgon, Sunrise, Evans Shoal and Browse projects, with a number of Shell-operated exploration interests in the Browse basin.

The North West Shelf project is a partnership between Shell, Woodside (operator), BHP Billiton, BP, Chevron and Japan Australia LNG. While BHP Billiton continues to pursue oil plays with additional acreage acquired in the Beagle sub-basin in Western Australia, Chevron's operating interest in Australia spans across 42,000sq km of acreage.

Leading the development of the Gorgon and Wheatstone natural gas projects, its latest discoveries, Chevron found natural gas in the greater Gorgon area located in the Carnarvon basin offshore northwest Australia. The group also has two exploration permits in the Great Australian Bight (GAB) of South Australia.

A hotbed for explorers, the GAB is one of the most unexplored prospective areas, holding billions of barrels of oil and gas. In 2011, BP secured four permits in the GAB, and conducted 3D seismic between November 2011 and May 2012.

The National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA), however, rejected BP's environment plan to drill four deepwater wells in the GAB, as it did not meet the criteria for acceptance under the environment regulations.

Similarly, neighbor New Zealand's Taranaki basin, which covers approximately 100,000sq km both offshore and onshore is proving to be an attractive investment for explorers like New Zealand Energy (NZEC), AWE Ltd., OMV New Zealand, Todd Exploration, TAG Oil and Mosman Oil and Gas, to name a few.

Currently, producing oil from nine wells, NZEC is executing a comprehensive development and exploration program to further increase production in the basin. While OMV's portfolio includes interest in the Maui, Pohokura and Maari fields within Taranaki, Todd is operator of six petroleum exploration permits.

Partnering OMV in the Maari oil field is Cue Energy, which also partners Todd in the offshore Altho prospect. AWE, too, is developing the Tui Area oil project offshore Taranaki, producing oil from four wells, connected to the floating production storage and offloading (FPSO) vessel, *Umuroa*.

Conclusion

According to APPEA's 2015 Key Statistics report, Australia is the third largest LNG exporting country after Qatar and Malaysia.

While oil, condensate and liquefied petroleum gas (LPG) production has been trending down since it peaked in 2000, APPEA says natural gas production has doubled since 1998. The country also still has significant quantities of discovered gas resources, much of which remains undeveloped.

New Zealand, on the other hand, holds vast petroleum potential and underexplored basins, mostly in the Taranaki region. The government aims to increase the value of petroleum exports from $2 billion (NZ$3 billion) to $20 billion (NZ$30 billion) a year by 2025, according to the New Zealand Trade and Enterprise. OE

Solutions

igus debuts plastic energy chain

At this year's Subsea Expo, igus showcased its E4.350 ESD energy chain, developed for oversized cables and hoses that need to be guided and protected. The engineering plastic used in the E4.350 is lighter and stronger than steel for a given size. In addition, it is resistant to corrosion and weathering, and unaffected by exposure to UV light from the sun.

Manufactured from igumid ESD, which dissipates electrostatic charge in a controlled manner, the energy chain is suitable for use in areas where the ATEX or IECEx standard applies.

Modular in design, the E4.350 energy chain can be shortened and lengthened. In addition, the energy chain offer rigidity and high load capacity when shear forces are at work due to their tongue and groove design. Specifications include, inner height: 350mm, inner widths: 400-800mm, bending radii: 500-1000mm and pitch: 470mm. **www.igus.com**

Amarinth delivers Umm Lulu pumps

Amarinth has delivered four sodium hypochlorite dosing pumps manufactured in titanium alloy to ADMA-OPCO's Umm Lulu development project, offshore of Abu Dhabi. Amarinth were approached by Cumberland to tender for the pumps on a tight 24 week delivery for the Umm Lulu platform. Sodium hypochlorite is highly corrosive and so traditional super-duplex materials cannot be used. Cumberland had considered using plastic components on the pumps but ruled that out due to known reliability issues and failure rates.

To minimize corrosion from the sodium hypochlorite, Amarinth proposed using titanium alloy for all wetted parts, including the casing, impeller and shaft.

The four titanium pumps have now been successfully manufactured and assembled and will be commissioned on the offshore Umm Lulu platform during H1 2016. **www.amarinth.com**

MJR introduces X-Wave

MJR Power & Automation, a UK-based supplier of integrated electrical engineering services, has introduced X-Wave, a self-learning motion compensation system that features a range of automation, electrical and control equipment from ABB.

X-Wave's self-learning routines bring automatic commissioning and self-optimization to the application. The system automatically learns the process characteristics, such as acceleration limits or flow response lags, to reduce commissioning. In addition, the system can predict sea motions including pitch, roll or heave, as well as modify and optimize the control system behavior in response to changing vessel dynamics.

As a standard solution, X-Wave can work with all actuators including rotary (winch), linear (cylinder) and hybrid (nodding donkey) as well as interfacing with hydraulic, pneumatic and electric power systems.

The system can control up to six degrees of freedom covering single axis 'heave' compensation of lifting devices such as cranes, winches and linear compensators through to multi-axis platform stabilization covering pitch, roll, heave, surge, sway and yaw. **www.mjrcontrols.co.uk**

Delmar releases ConStatAU

Louisiana-based Delmar has launched ConStatAU risk assessment software for the Australian market. The ConStatAU risk assessment software is an automated program that allows operators to survey up to 190 km from their location for any possible risk factors including pipelines, wells, surface facilities, and environmental sites.

Using historical storm data, it highlights possible drift directions and seasonal probabilities to produce a detailed potential risk profile. Additionally, the software meets government standards for risk assessment, a key consideration in the awarding of offshore contracts. **www.delmarus.com**

AnTech expands WHO range

AnTech has expanded its Type-C Wellhead Outlet range: types CB, CC and CD. Each adaptation has been designed to suit various working environments including pressure, ranging from 5000 - 15,000psi, temperatures from -60-160°C, and various voltages.

The Type-C Wellhead Outlet, compliant with API 6A, ATEX and NACE standards, is designed and developed for use in hazardous environments. Type CB and CC are focused on lower cost applications, where a high level of specification is required. Furthermore the Type-CD wellhead outlet has been designed accredited with the Type 1, Division 1 certification allowing it to safely operate in stringent wellsite environments including the Gulf of Mexico.
www.antech.co.uk

API certifies Trelleborg equipment

Trelleborg's UK offshore operation has been certified for the manufacture of bend restrictors under the American Petroleum Institute's (API's) specification for flexible pipe ancillary equipment (API 17L1 Ed. 1 2013). The company says the certification demonstrates the performance of the bend restrictors, especially for use in challenging and harsh sea environments.

API 17L1 is an industry standard that determines the minimum requirements for the design, material selection, manufacture, documentation, testing, marking and packing of flexible pipe ancillary equipment. Trelleborg's offshore operation now has certificates for API 17L1 for bend restrictors, bend stiffeners and modular buoys.

The certificate was completed by Lloyds Register EMEA, acting as an independent verification agent. **www.trelleborg.com**

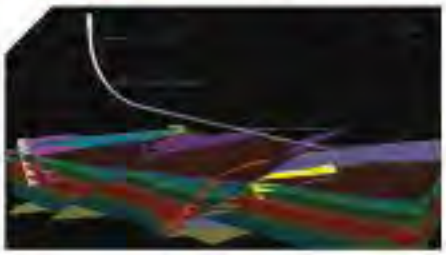
Proserv adds to valve offering

Proserv Gilmore has introduced a critical service valve suite using dual direction key seal and shear seal technologies. The suite of control valves has been developed for harsh environments encountered in the oilfield.

A client in the wireline sampling arena commissioned Proserv Gilmore to design a valve to increase the temperature and pressure range of its tools. The objective was to design a 2 Way, 2 Position (2W 2P) dual direction sealing sample bottle valve that achieves higher pressure and temperature operation.

During the development of the 2W 2P valve, Proserv Gilmore developed the Key Seal to shift the paradigm of high pressure, high temperature dual direction sealing. The Key Seal met the critical requirements of the 2W 2P dual direction sealing in down hole service, and formed the nucleus of the critical service valve suite. Proserv Gilmore consistently pushes the envelope of higher pressures and temperatures (up to 28,500psi at up to 400°F) while being able to reliably operate on corrosive, debris laden fluids.
www.proserv.com

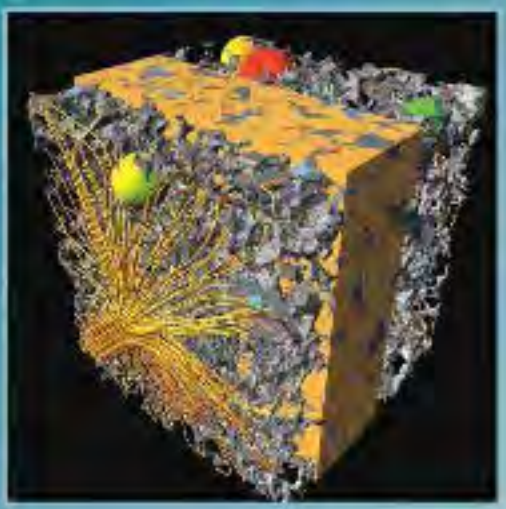
Paradigm releases Sysdrill 10.5



Paradigm has released Paradigm Sysdrill 10.5, an upgrade to its integrated suite of well planning and drilling engineering applications. New features include updated modeling, including HDGM for declination calculation and ISCWSA Rev 4 error models. Sysdrill 10.5 is also now fully translated into both Russian and Chinese languages.
www.pdgm.com

FEI unveils PerGeos

FEI has released PerGeos, a comprehensive digital rock software that helps geoscientists interpret and model digital rock imagery.
Multi-scale, microscopic imagery and advanced digital rock modeling provides direct measurement for analyzing critical structural characteristics and physical properties, such as grain size, pore space and connectivity.
Using PerGeos, core analysts, geologists and petrophysicists can integrate data from multiple sources and share descriptions and statistics using a common platform. It features automated workflows, high-powered image processing algorithms.
The initial PerGeos release consists of three modules: petrophysics, pore statistics and core profile. Each module is designed to help users make statistical observations about the sample as it relates to their specific function, and then allows them to transfer this knowledge to a digital environment for interactive assessment by the entire asset team.
www.fei.com



Activity

Offshore Achievement Awards finalists unveiled

The shortlist for the 2016 Offshore Achievement Awards were announced. The awards, supported by *OE*, received 100 entries this year, a record since the awards were re-launched in 2011 by the Society of Petroleum Engineers (SPE) Aberdeen Section. The winners will be revealed at a black-tie dinner, which takes place at the Aberdeen Exhibition and Conference Centre on Thursday 17 March.

Last year's winners (from Offshore Achievement Awards facebook)

The finalists for the 2016 Offshore Achievement Awards are:

Emerging Technology
- EC-GG
- Interventek Subsea Engineering
- OneSubsea
- Well-SENSE Technology

Innovator
- Darcy
- Sea Energy
- Step Change Engineering

Safety Innovations
- Cape Industrial Services
- Churchill Drilling Tools
- Cybernawk Innovations
- N-Sea

Environmental Innovation
- CETCO Energy Services
- EC-GG

Export Achievement
- Churchill Drilling Tools
- Equalizer International
- TWMA

Collaboration
- ADIL
- N-Sea
- Paradigm Flow Services, STATS Group and Halliburton
- Peterson

Outstanding Skills Development Programme
- 3Sun Group
- Aker Solutions
- Caledonian Petroleum Services

Young Professional
- Jason Fong, Coretrax
- Hayleigh Pearson, Costain
- Emily Taylor, Step Change in Safety

Above & Beyond
- Callum Falconer, Decom North Sea
- Andrew Lucas, Harris CapRock Communications
- Allan Smillie, TAQA

Great Small Company
- Aisus Offshore
- Marine Technical Limits
- Plant Integrity Management
- Well-Centric Oilfield Services

Great Large Company
- ADIL
- Amec Foster Wheeler
- Tendeka

Subsea UK Awards finalists announced

Aker Solutions, N-Sea and Saab are in contention for the Subsea Company of the Year award at this year's Subsea UK Awards, held during Subsea Expo – Europe's largest subsea focused exhibition and conference, and supported by principal media partner *OE*. Neil Gordon, chief executive of Subsea UK, said: "2015 was a challenging year for everyone in the subsea sector. Despite the downturn however, there have been some outstanding subsea successes, which truly underlines the strength of our sector both at home and overseas. It's crucial that we continue to recognize the ongoing efforts of our companies and the individuals who are making a concerted effort to contribute to the long-term sustainability of our industry."

Proserv won company of the year in 2015.
From Subsea UK

Aker takes knife to MMO business

Aker Solutions is to "streamline" its maintenance, modifications and operations (MMO) unit in Norway from four units to one regional unit. The company said it was taking "necessary steps to reposition the business and enhance competitiveness in a market with unprecedented challenges."

The move could impact up to 900 permanent management and staff positions at facilities in Stavanger, Bergen, Kristiansund, Trondheim, Tromsø and Sandnessjøen as well as offshore. The workforce reductions will be made through regular employee turnover, reassignments to other parts of the company and redundancies, with a process to implement about half of the reductions starting immediately.

The company's prefabrication workshop in Sandnessjøen will be temporarily shut for about three years. MMO operations in Tromsø will be terminated, though some employees in this strategically important northern location will likely be kept on as part of the company's Arctic Hub. These employees will join Aker Solutions' Engineering and Front End Spectrum teams.

Aker Solutions already reduced capacity in its Norwegian MMO business by about 1300 permanent and temporary positions, since July 2014, to adjust to a market slowdown.

Wood Group, Magma form commissioning duo

Wood Group has established a collaborative agreement with international engineering consultancy, Magma Products to extend its existing commissioning service. Headquartered in Aberdeen and specializing in the field

Trelleborg opens inspection facility

Trelleborg Sealing Solutions has opened a dedicated climate-controlled swivel stack seal inspection facility for the validation of custom seals for floating production, storage and offloading (FPSO) operators. Located in Barendrecht, Netherlands, the facility provides a temperature-controlled environment to avoid fluctuations in the dimensions of the seals caused by temperature changes, with specialist storage racks allowing the seals to be acclimatized prior to inspection. In addition, a custom inspection table has been installed, on which seals up to 3000mm can be measured with special lighting to aid visual inspection.

of commissioning and start-up. Magma's services and software system will complement Wood Group's global commissioning experience.

Under the collaboration, Wood Group and Magma will work together to offer enhanced capabilities and greater efficiencies in delivering commissioning work.

Europe approves Saipem sale

The European Commission has authorized Italy's Eni to sale 12.5% of its stake in its subsidiary Saipem to Fondo Strategico Italiano (FSI). Eni is set to net US$507.8 million (€463 million) from the Saipem stake sale, a value of $9.204 (€8.396) per share that was first agreed upon in October 2015. The agreement is for a period of three years, with automatic renewal for a further period of three years, unless terminated by notice. Upon closing, Eni will lose exclusive control over Saipem.

ExxonMobil, Hunting in tech partnership

ExxonMobil Upstream Research Co. and Hunting Energy Services' Titan division have signed a joint development agreement to develop new autonomous tools technology focused on well construction and intervention efficiency.

The two Houston-based companies said they expect to produce the first commercial autonomous tools in a few years with initial tools focused on perforating and pipe cutting devices.

The agreement brings together Hunting Titan division's equipment manufacturing capabilities and expertise in tool development, energetics and safety systems and ExxonMobil's autonomous tools technology and expertise in a unique on-board navigation system.

HitecVision forms Point Resources

HitecVision will merge Pure E&P, Spike Exploration, and Core Energy into Point Resources, a mid-sized independent oil company focused on the Norwegian Continental Shelf (NCS). The new company will engage in both exploration, development and production on the NCS.

Point Resources will have ownership in 57 licenses, interest in several discoveries, and oil and gas production of about 10,000 b/d. Roar Tessem, currently CEO of Pure E&P, will become CEO of Point Resources.

The merger of the three companies into Point Resources is expected to close during H1 2016, subject to final approval from Norwegian authorities.

Hardide opens US facility

Hardide Coatings has opened its new 26,000sq ft Virginia production facility in Martinsville-Henry County. It will service existing and new customers for the company's range of tungsten carbide coatings.

"Having a local production facility in North America will support the increased demand from existing customers and significantly boost opportunities to expand provision of our coatings throughout the region," said Philip Kirkham, CEO of Hardide. "We have installed two large capacity chemical vapor deposition (CVD) coating reactors and work is already progressing well on some very exciting customer trials."

Statoil takes near-12% stake in Lundin

Norwegian oil major Statoil has acquired an 11.93% stake in Swedish exploration firm Lundin Petroleum's shares. Statoil says the move increases its indirect exposure to core assets on the Norwegian Continental Shelf (NCS), including the Johan Sverdrup and Edvard Grieg fields.

"We consider this a long term shareholding. The Norwegian Continental Shelf is the backbone of Statoil's business, and this transaction indirectly strengthens our total share of the value creation from core, high value assets on the NCS," says Eldar Sætre, president and CEO of Statoil.

Spotlight

Right place, right time

Audrey Leon chats with Gerald (Jerry) Stone, senior vice president, Fluor Offshore Solutions, about his unlikely career in engineering, his take on the current market situation, and his work in harsh environments.

Gerald Stone

Gerald Stone, senior vice president, Fluor Offshore Solutions, comes from a military family, and it is that background that eventually put him on a path toward civil engineering that has led him all over the world, and to take on harsh environment projects such as Hebron offshore Newfoundland, Canada and Sakhalin Island, offshore Russia. His career path, Stone told *OE*, was just being at the "right place at the right time."

Stone's father retired from the military as a sergeant major, and Stone's family traveled the world, living abroad in France and Germany. Stone, who was born in Alaska, eventually attended school at The Citadel earning a Bachelor of Science in civil engineering. After graduating, he spent 10 years as an engineer in the US Army, eventually joining the US Army Corps of Engineers, which led him to earn a master's in civil engineering from Clemson University. Stone joined Fluor in 1989, first coming up through the ranks on the construction side, but eventually serving on megaprojects on the oil and gas side.

Stone served as program director for Fluor's work on Sakhalin Island and led the formation of Fluor's Russian joint venture, Sakhalin Neftegas Technology. This work has been ongoing since 2003, and has consisted of four major projects – and a few smaller capital projects – amounting to US$10 billion over the last 12 years. The company's scope of work has included a 250,000 b/d onshore processing facility on the island, a satellite facility, offshore pipelines, two offshore platforms, and Stone says, Fluor is now also working on an expansion to the satellite facility.

There are plenty of issues involved with harsh environments that make the work complicated. "Weather is always a factor; the sea lift window is always a factor," Stone says. "We have to do everything around delivering modules and offshore kits in a pretty tight weather window on Sakhalin Island. That's part of the logistics and other things we have to deal with. Any work in and around the island is very expensive so we try to get everything modularized and we try to get the kits completed and fully pre-commissioned before we even get there."

To help Fluor accomplish their work off Sakhalin, the company created another joint venture called ASGS, on Russia's Sakhalin Island, which offers full-service fabrication and modular assembly solutions. Fluor has repeated this strategy in China, where, in 2015, it formed a new joint venture with COOEC called COOEC-Fluor Heavy Industries Co., Ltd. The two companies will own, operate and manage the 2 million sq m Zhuhai fabrication yard in the Guangdong province, which will be able to accommodate fabrication modules weighing more than 50,000 tons.

The new yard in China is part of the reason why Stone remains positive about the industry despite the oil price.

"Everyone is thinking that the offshore market is going to be stressed," Stone says. "I'm a little bit counter to that. Particularly because of the yard in Zhuhai. The impact of this venture in China – some of it has to be because offshore projects are longer term plays for owners. Immediately we started getting inquiries from clients."

Stone explains that the average time from when operators find the play to when it achieves production can take between 10-20 years, and no matter what the current price is, most choose to keep projects moving forward.

Stone remains positive that the impact of the new yard will also spread to new markets for the offshore division, including opening Fluor to the FPSO and decommissioning markets. And while the news hasn't been too positive for FPSOs, Stone believes there is life yet in that market.

"There are a lot of FPSOs that people are wringing their hands about, but there are still other FPSOs that we know are moving forward," Stone says. "Some will be leased, and in the past we hadn't considered that market, but we are very interested and we believe we will have a play in assisting that market." **OE**

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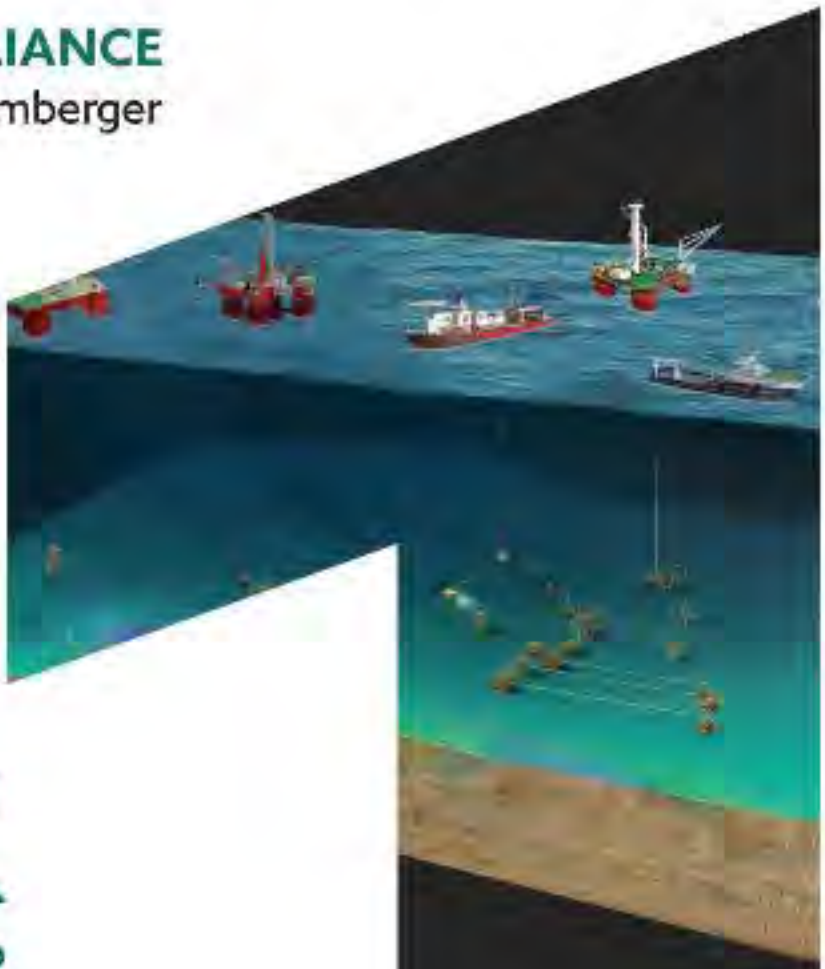

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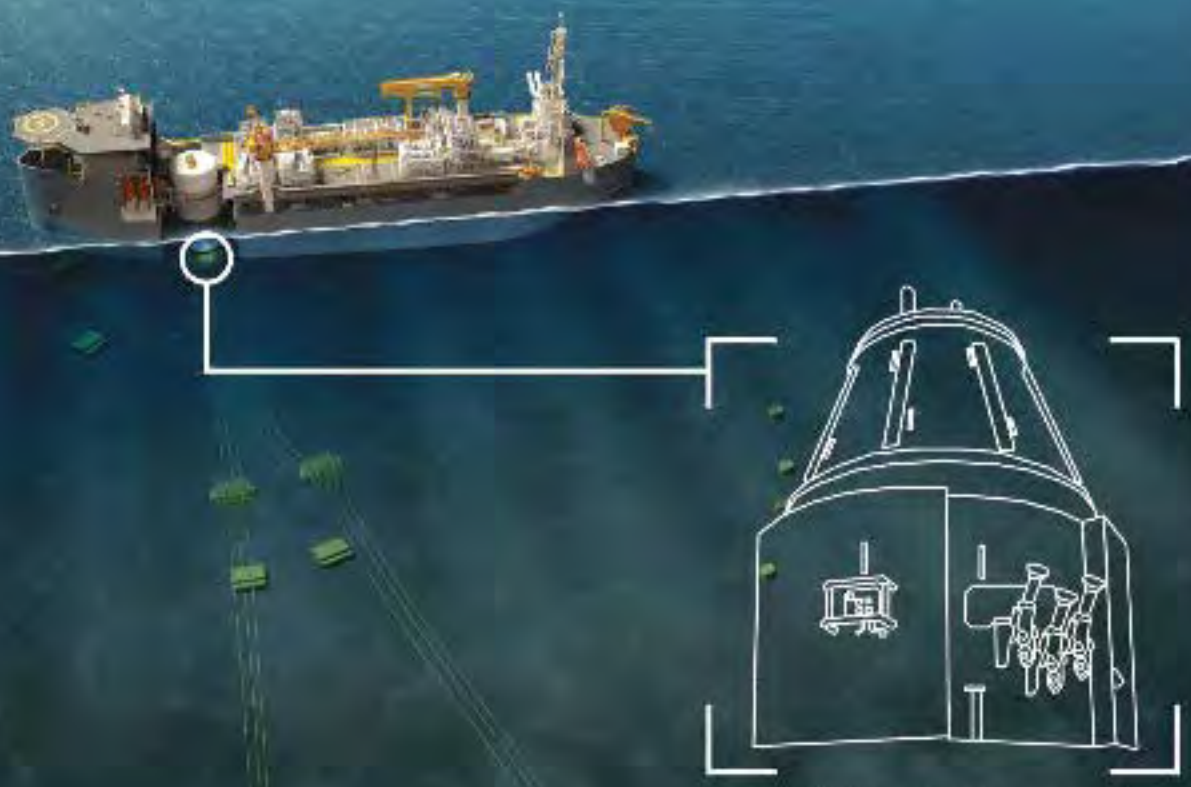

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