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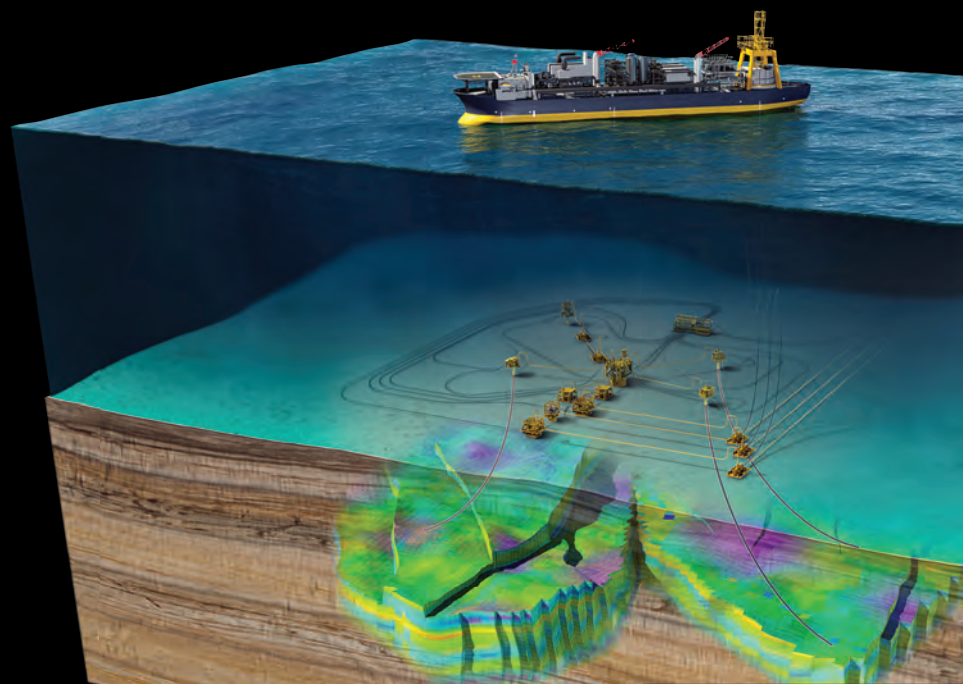

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Feature

Deepwater intervention

ON THE COVER

Blue skies ahead. This month's cover features the Q5000 from Helix Energy Solutions. The DP3 well intervention vessel will arrive in Galveston, Texas, the first week of August for final commissioning. This just happens to coincide with ***OE***'s Deepwater Intervention Forum, also in Galveston. Read more about the forum on page 24. Cover *photo and photo on top of page by Neil M. Johnston.*

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Volume 40, Number 8 August 2015

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

US POSTAL INFORMATION
Offshore Engineer (USPS 017-058) (ISSN 0305-876X) is published monthly by AtComedia LLC, 1635 W. Alabama, Houston, TX 77006-4196.
Periodicals postage paid at Houston, TX and additional offices.
Postmaster: send address changes to Offshore Engineer, AtComedia, PO Box 2126, Skokie, IL 60076-7826

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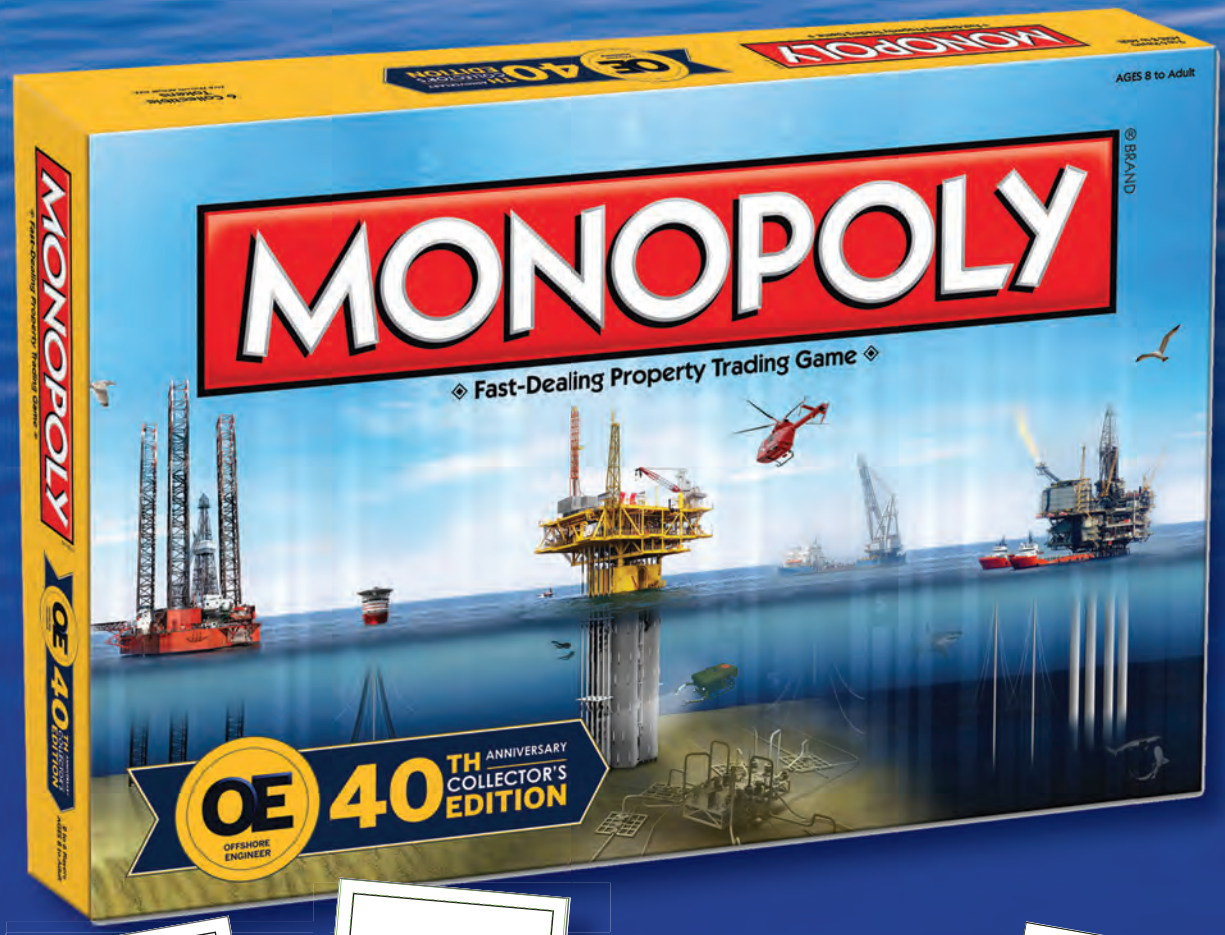

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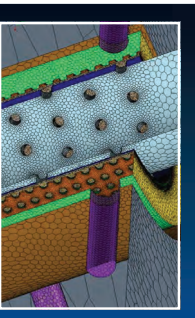

Well-modeling process optimizes production strategies

LR Senergy's new process uses computational fluid dynamics (CFD) to model a well and near wellbore — and subsequently identify production optimization options and strategies. Jeannie Stell reports.

What's Trending

Team work

- **OneSubsea, Subsea 7 form alliance**
- **Subsea 7, KBR form FEED alliance**
- **Halliburton, Baker Hughes merger gets DOJ extension**

People

AAPG gets new president

John Hogg, president at Skybattle Resources in Calgary, Canada, has assumed the presidency of the American Association of Petroleum Geologists (AAPG).

Undercurrents

All eyes on Mexico

As *OE* went to press this month, Mexico's energy regulators and other officials were dealing with the disappointing aftermath of Mexico's historic and highly anticipated Round One offshore tender. Mexico had offered 14 blocks in shallow water areas off the coast of Veracruz and Tabasco. Just days leading up to the bidding round, held on 15 July, several companies withdrew from the process: Houston-based Noble Energy, Glencore E&P, Colombia's Ecopetrol, Thailand's PTTEP, and even Mexican national oil company Pemex.

Of the 14 blocks up for grabs, only two areas – Blocks 2 and 7 – were awarded, both to the Talos consortia made up of Houston-based Talos Energy (45%, operator), Mexico-based Sierra Oil & Gas (45%), and UK-based Premier Oil (10%). Block 2 covers a total area of 194sq km off Veracruz at 31m water depth with expected recovery of dry gas and light oil. Block 7 covers a total area of 465sq km off the coast of Tabasco at 142m water depth, with expected recovery of light oil. Both blocks contain Tertiary clastic plays, typical of the Salinas sub-basin. The Talos consortia says that it plans to acquire, evaluate and reprocess 3D seismic data with a view to firming up drilling locations towards the end of 2016.

Mexico's ministry of energy, SENER, announced after the bid round that Mexico stands to receive 74% and 83% of the profit generated by the contracts for exploration and extraction, for blocks 2 and 7, respectively. SENER also estimates that the two awarded areas could draw US$2.7 billion over the life of the contracts.

While two blocks were awarded, that's not to say that other companies didn't try. Bids were rejected from consortia consisting of Murphy Oil and Malaysia's Petronas, as well as Italy's Eni and partner CASA Exploration. Solo bids from India's ONGC Videsh and Norway's Statoil were dismissed for being too low.

So where does Mexico go from here? Well, it's time to start listening to the industry. While Mexican officials blamed the current low oil price environment for the failed Round One exercise, several concerns were raised prior to the round. One concern was that the contract terms and royalty rates were not attractive enough. Another was that the quality of the blocks on offer were also not attractive to bidders. As Duncan Wood, director of the Mexico Institute at the Wilson Center in Washington, D.C., wrote in the Financial Times, Mexico's finance ministry must examine the corporate guarantee requirements and the minimum bid standards, as well as pursue a more market-oriented approach, in terms of the blocks put on offer and of the regulatory and legal framework.

SENER's Pedro Joaquín Coldwell. Photo from SENER.

"Officials should be asking themselves what they can do to increase the interest of the private sector, rather than their current discourse that emphasizes the guiding hand of the state," Wood said.

One thing is certain: interest in Mexico's oil and gas sector, both on- and offshore, remains strong, and will only increase if better terms are negotiated for future rounds. OE

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Since 1975, *OE (Offshore Engineer)* has enjoyed being close to the offshore action. In the past, we've encouraged you to send in your photos. As it's our 40th birthday this year, we like to do so again. Send us your photos from offshore, or even the fabrication yard or manufacturing facility (subject to company approval!).

We will feature the best in the magazine, over the coming months, with a selection of the top shots to be featured in our anniversary year end issue in December and online.

See if you can do better than these fantastic shots from Hans Elbers – taken by attaching a camera to a kite – in the Caland Canal, Rotterdam, which show the *Dockwise Vanguard* heavy transport vessel loaded with the *Armada Intrepid* floating production, storage and offloading (FPSO) vessel before it sailed to Indonesia.

Send your photos to **news@oedigital.com**.

All photos Hans Elbers, www.fotovlieger.nl

ThoughtStream

Matt Loffman and Marina Ivanova, Douglas Westwood

Tackling geopolitics and oil prices

A busy week for global news mid-July sent crude prices plummeting. The agreement between the Greek government and European financial ministers left a lingering uncertainty hanging over the Eurozone, with several high profile organizations remaining openly critical of it. Elsewhere in the news, erratic Chinese equity markets and a landmark Iranian nuclear deal all served to dampen crude prices. The concern for oil markets centers around several factors: the consequences for economic stability and growth in Europe and China, the prospect for additional crude volumes into an already over-supplied market and the strengthening of the US dollar.

Greece itself consumes less than 0.4% of global crude, produces fewer than 9000 b/d and had an economy of US$240 billion last year – around 0.3% of the global total. An exit from the Euro, which now seems less-likely, threatens the breakup of the Eurozone itself, a major global economy and consumer of 9.7 MMb/d. Should Greece "walk away" from her debts, exposure to the debt in other member states, coupled with premiums for borrowing (particularly in southern Europe) could be expected to usher in another period of recession. Estimates from the International Monetary Fund suggest a contraction of between 2% and 5% is possible. While this picture remains uncertain, historical linkage of oil consumption and gross domestic product growth would imply a potential reduction of 360,000 boe/d per year in consumption. Tiny indeed, but in an over-supplied market, every portion of demand is important.

Ever-deeper uncertainty within Eurozone economies, however, is likely to increase the flight of capital to dollar-based equities. The Euro has already fallen 18% against the dollar in the past 12 months and a Greek exit would likely dampen this significantly as investors look nervously at other debt-laden Euro members. A strong dollar weakens international oil demand as the commodity, traded in US dollars, is more expensive on a relative basis.

The Euro has already fallen 18% against the dollar in the past 12 months and a Greek exit would likely dampen this significantly as investors look nervously at other debt-laden Euro members.

After 10 years of diplomatic negotiation, the UN P5+1 countries (the US, the UK, France, China, Russia and Germany) at last reached an agreement to unwind economic sanctions on Iran in return for significant international control and surveillance over its nuclear activities. The long-awaited deal will revive foreign investment in Iran, as Western international oil companies (IOCs) renew pre-sanction projects. Brent dropped $1.15 to $56.70/bbl on the back of the announcement, with markets fearing a worsening of the global supply glut.

Iran holds the world's fourth-largest oil reserves and second-largest gas reserves, while being the second largest OPEC producer after Saudi Arabia. In 2014 total Iranian production, heavily driven by gas and condensate production from the giant South Pars offshore field, amounted to 6.7 MMboe/d. During the sanction period, however, Iran had limited access to technology from the West and complex LNG export terminal projects stalled. Vast capital inflows will now be required to develop under-invested Iranian fields, however, due to the large reserves base, Douglas Westwood believes appetite to invest in Iran will be strong amongst major operators.

While no sanctions will be lifted before December, Douglas Westwood believes that Iranian liquids production will rise to a 2015 average of 3.5 MMb/d, based on pre-sanction production levels and available oil currently stored in storage tankers off Iran. Further production gains are expected as additional development phases of South Pars come onstream, while the removal of sanctions will clear supply bottle necks out of the Persian Gulf. IOC investment in the country's huge potential will further boost production as sanctions are rolled back, though any new projects will see a lag of several years from lease acquisition to production phases.

Global oil prices have been weighed down in recent months by resilient US production, record Saudi output, continued weakness on the demand side, and the Grexit prospect. While commodity prices are unlikely to be aided by an opening of Iranian taps, the true tidal wave of Persian crude could be later rather than sooner. OE

Matt Loffman, manager, Houston, and Marina Ivanova, researcher, Douglas Westwood.

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Global E&P Briefs

A Arctic problems

As Shell inches closer to its Burger drilling program in the Chukchi Sea, the last of two drillships, *Noble Discoverer*, left the Port of Everett, Washington, on 30 June. The *Fennica* icebreaker vessel, which was to be part of Shell's drilling program, was forced to head to Portland, Oregon, to undergo repairs after its hull was breeched. Meanwhile, BP and ExxonMobil suspended a Canadian Arctic exploration program in the Beaufort Sea region due to insufficient time to begin test drilling before its lease expires in 2020. ExxonMobil's affiliate, Imperial Oil, is seeking to have its current lease extended to 16 years.

The Fennica ice breaker from Arctia Offshore will undergo repairs in Oregon. Photo from Arctia.

B Talos Consortia wins in Round One

Of the 14 blocks up for grabs in Mexico's Round One, only two areas – Blocks 2 and 7 – were awarded, both going to the Talos consortia made up of Houston-based Talos Energy (45%, operator), Mexico-based Sierra Oil & Gas (45%), and UK-based Premier Oil (10%).

Block 2 covers 194sq km off Veracruz at 31m water depth. Block 7 covers 465sq km off the coast of Tabasco at 142m water depth. Both blocks are said to contain Tertiary clastic plays, typical of the Salinas sub-basin. The consortia plans to acquire, evaluate and reprocess 3D seismic data with a view to firming up drilling locations towards the end of 2016.

C Stone updates Cardona

Stone Energy's Cardona No. 6 development well, in Mississippi Canyon block 29, has completed drilling. The well, drilled with the *Ensco 8503*, encountered 288ft of net pay in two intervals. The existence of oil in the pay zones has been confirmed through logging and pressure data. The well has been successfully cased and cemented across all productive zones, the subsea tree has been installed and completion operations have begun. The well will be tied into the Pompano platform via the existing Cardona subsea infrastructure.

D Perla onstream off Venezuela

Production has begun at the giant Perla gas field, 50km off Venezuela in the Cardón IV Block, at 60m water depth. It is the first gas field in production offshore Venezuela.

The field holds 17 Tcf of gas in place, which corresponds to 3.1 billion boe, with additional potential. The best wells are estimated to produce over 150 MMscf/d each. There are three phases planned for Perla. Phase 1 (early production) will have a production plateau of about 450 MMscf/d; Phase 2 has a plateau of 800 MMscf/d from 2017; and Phase 3 has a plateau of 1.2 Bscf/d from 2020.

Perla is operated by Cardón IV, a company jointly owned by Eni (50%) and Repsol (50%). Cardón IV signed a gas sales agreement with PDVSA for all three phases until 2036.

E Petrobras cuts investments

Brazilian national oil company Petrobras has approved a new five-year investment plan for 2015-2019, which slashes total investments by 41% from last year's estimates to US$130.3 billion.

Exploration and production will take the largest chunk ($108.6 billion). Petrobras says 86% of that $108.6 billion will be allocated to production development, 11% for exploration, and 3% for operational support. Approximately $64 billion will be spent on new production systems, 91% geared toward the pre-salt.

Petrobras also expects to reach 3.7 MMboe/d of oil and gas production (total of Brazil and international) by 2020, estimating that the pre-salt will make up more than 50% of total oil production.

F Alder begins commissioning

Chevron Upstream Europe has installed a new topsides module on to its Brittania bridge-linked platform, paving the way for the start-up of the HPHT Alder field. Alder sits in Block 15/29a, 160km from the Scottish coastline, in 150m water depth and will be tied back to the Brittania platform via a 28km pipeline. The project has a planned design capacity of 110 MMcf/d natural gas and 14,000 b/d

condensate. The Alder well is expected to be drilled in 2015 with the *Blackford Dolphin* semisubmersible drilling rig, with first production is expected in 2016.

G Gullfaks development plan changes

Statoil and its partners submitted an amendment to the plan for development and operations for the Gullfaks license to the Ministry of Petroleum and Energy for phase 1 of the Shetland/Lista development. Phase 1 of the development is expected to add 18 MMboe.

The development concept will reuse 15 existing wells from the Gullfaks platforms and will not require new infrastructure, in an effort to increase profitability. Investment costs are estimated at some US$114.7 million (NOK 900 million).

H Sakhalin gets bigger

Russian gas producer Gazprom and Shell signed an agreement to expand the Sakhalin-II LNG project.

Sakhalin-II saw the development of two offshore oil and gas fields: Piltun-Astokhskoye and Lunskoye, off the north-eastern coast of Sakhalin, later followed by two LNG trains – Russia's first LNG facility with capacity for 8.7 MTPA of LNG. The firms are looking to develop a third LNG train with additional gas volumes to be produced by the Sakhalin III project.

In support of the Sakhalin III project, 3D surveys and exploration will be carried out on the Ayashsky and Costochno-Odoptinsky blocks further north.

I Cameroon FLNG reaches milestone

Golar LNG, the national oil firm Societe Nationale de Hydrocarbures and French independent Perenco have agreed the commercial terms for Africa's first floating LNG (FLNG) export project. The move will bring natural gas from the offshore Kribi fields to market via a FLNG unit, which will be stationed 20km offshore Cameroon. The joint venture anticipates allocated reserves to be produced at the rate of 1.2 MPTA of LNG over an eight-year period, with production slated to being in 1H 2017.

J Tullow's TEN starts installation

Tullow Oil's TEN project offshore Ghana is ramping up for offshore installation activities and is on budget and on track for first oil by mid-2016.

The TEN project, named for the Tweneboa, Enyenra and Ntomme fields, is a floating production, storage and offloading (FPSO) vessel development in the Deepwater Tano contract area. The project, which sits close to the border with Ivory Coast, will produce via 24 wells, in 1500m water depth.

In 2Q 2015, the firm ran the first two of 10 well completions on the project, the TEN FPSO turret was installed, and the first in-country fabrication works were made ready for the start of the offshore installation campaign in mid-July.

K Iran agreement

Sanctions on Iran's oil production look set to be lifted after the country and six world powers finally reached a deal over the country's nuclear program. The move could finally reopen Iran to international oil companies and contractors and enable the country to ramp up production back to its pre-2012 2.5 MMb/d level.

Iranian officials said that if a nuclear accord is reached and sanctions are lifted, Iran can double its oil exports in the next six months by producing 1 MMb/d. However, Wood Mackenzie says it would be a gradual process with sanctions not fully lifted until mid-2016.

L Noble, Israel move forward

The Israeli government has decided to move forward in the development and expansion of natural gas fields off the country's coast. It is expected that the country will allow Noble Energy and its partners to keep control of its

mega-discovery Leviathan, which is thought to hold 19 Tcf of gross natural gas resources. Under the proposal, partner Delek will have to sell its stake in the Tamar field, and Noble will have to decrease its take from 36% down to 25%. Both companies will be expected to sell interest in two smaller Israeli gas fields, Tanin and Karish. However, no timeline has been given for the official decision. Noble's main opponent of its Leviathan plans was Director General of the Israeli Antitrust Authority, David Gilo, who will resign his position this month.

M BG starts renewables-powered platform

First oil has been produced from the Mukta-B, a four legged renewables-powered unmanned wellhead platform in the offshore Bombay basin, India. The Mukta field is part of the Panna-Mukta oil and gas field contract area, 95km offshore Mumbai in the Arabian Sea at 47m water depth.

The new platform both brings on additional production, through six new development wells, with a further three planned, as well as enabling production to restart from the MA platform, fluids from which have been redirected via the MB platform to the main processing platform.

N Otto mobilizes Maersk Venturer

Otto Energy has mobilized Maersk Drilling's ultra-deepwater drillship *Maersk Venturer* for the Hawkeye-1 exploration well, offshore Philippines. Rated for 3600m (12,000ft) water depth, *Maersk Venturer* will start drilling operations when the rig arrives on location.

The Hawkeye prospect, in service contract 55, is offshore the Palawan Basin in the Philippines, and contains a best estimate stock tank oil initially in place of 400 MMbbl and 74 MMbbl best estimate net prospective resources. Otto has planned Hawkeye as a vertical exploration well to test the clastic late Miocene Pagasa formation.

O Mitra sizes up Vietnamese prospects

Mitra Energy completed the acquisition of 533sq km of full-fold 3D seismic data at Block 127 production sharing contract area, offshore Vietnam. The survey was undertaken by PTSC CGGV Geophysical Survey Co. using the 3D seismic survey vessel *Amadeus*. Mitra operates the PSC with 100% equity.

P Browse FLNG enters FEED

Australian operator Woodside Petroleum will press forward into the FEED phase for its long-struggling Browse LNG mega project.

The Browse FLNG development concept is based on three FLNG facilities using Shell's FLNG technology and Woodside's expertise to commercialize the Brecknock, Calliance and Torosa fields.

The FEED phase will help determine a final investment decision by the Browse partners by 2H 2016, Woodside said.

The fields, 425km offshore north of Broome in Western Australia in 300-700m water depth, are thought to contain gross (100%) contingent resources (2C) of 15.4 Tcf of dry gas and 453 MMbbl of condensate.

Contract Briefs

2H Offshore wins Stampede work

2H Offshore has won two separate contracts, one from Hess and a second contract from Enbridge Energy, to verify the design, fabrication and installation phases of the steel catenary risers (SCRs) for the Stampede field development in the Gulf of Mexico. 2H's verification work is to verify the acceptability of the Stampede SCR design, fabrication methods and installation activities for both Hess and Enbridge, and ensure that there is consistent adherence to the relevant codes, standards and specifications.

Technip bags Libra FPSO topsides contract

Technip has been chosen to provide detailed engineering and procurement services for the topsides on Brazil's multi-billion barrel pre-salt Libra field floating, production, storage and offloading vessel's topsides. Technip's operating center in Kuala Lumpur, Malaysia, will execute the contract, scheduled for completion during the second semester of 2016.

Baker Hughes lands Johan Sverdrup gig

Baker Hughes won a US$190 million (NOK1.5 billion) contract for integrated drilling services on the massive Johan Sverdrup field offshore Norway. The contract covers cementing and pumping, completion, drilling and completion fluids, offshore cuttings handling, and integrated drilling services, will be valid for six years with a four-year extension option for the entire field life.

Gazprom axes Saipem from South Stream job

Gazprom handed Eni subsidiary Saipem a termination notice for the South Stream pipeline project to transport gas via a pipeline in the Black Sea. South Stream Transport, a Gazprom subsidiary, will move forward with potential contractors to lay the first line of the South Stream replacement project, now called TurkStream. South Stream Transport had awarded Saipem the US$2.7 billion contract in March 2014 to construct the line of the project, along with the shallow water parts, shore crossings and associated facilities for all four pipelines.

DNV GL wins Wintershall work

Wintershall Norge awarded DNV GL a US$1.2 million (NOK 10 million), five-year frame agreement for global inspection services for the its developments offshore Norway. The contract covers all Wintershall's projects on the Norwegian Continental Shelf, and will initially be used for the ongoing Maria development.
DNV GL's Stavanger office will coordinate the agreement with resources from the inspection division.

OneSubsea bags Browse FEED

OneSubsea has won a front-end engineering and design contract on the Browse FLNG development offshore Australia from operator Woodside Petroleum. Under the contract with Woodside, a team from OneSubsea, operating out of OneSubsea's Perth city office, will work with Woodside to fully define and determine the optimal subsea production system design and equipment requirements for the Browse FLNG Development over the next 12-18 months as Woodside prepares for a final investment decision.•

Two for one

When developing the Lucius and Heidelberg fields in the deepwater Gulf of Mexico, Anadarko Petroleum opted for a "design one, build two" strategy. Audrey Leon reports on how the Lucius field, which began production in January, came to be.

Anadarko's Lucius truss spar when it came onstream in January 2015. Photo from Robert Seale/Anadarko Petroleum.

In January, Anadarko Petroleum brought its Lucius field online using a truss spar design. The Lucius development is the first created via the US independent's "design one, build two" strategy. A second spar, Heidelberg, left Corpus Christi, Texas, in late June and has been upended at its namesake field. It is now swiftly moving toward first production, due by April 2016.

The Lucius field is approximately 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 first exploration well, drilled in 2009, encountered roughly 200ft of net pay in subsalt Pliocene and Miocene sands. The find was described as a three-way structure against salt with indications of thick reservoir sands with very good porosity and permeability.

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%).

At the time the discovery was announced, Anadarko had considered utilizing its recently decommissioned Red Hawk spar (*OE: May 2015*) to produce the Lucius field. Instead, the independent chose to construct a new standalone facility. A tension leg platform was dismissed as a possibility due to the water depth as well as the current technical and cost limitations on tendons, Anadarko's Lucius Project Manager Matthew Lamey and his co-authors said in OTC paper 25868-MS, presented at this year's OTC in Houston. Additionally, other considerations included the need to avoid landing the umbilicals and steel catenary risers (SCRs) in less desirable areas with slopes, indicating less stable surfaces.

Ultimately, Anadarko went with a truss spar given its previous experience with the technology on its Boomvang, Nansen, Gunnison, and Constitution developments.

"A truss spar was chosen because it could utilize three groups of mooring lines, while four group of moorings lines associated with a semisubmersible would have been difficult to implement given the geotechnical challenges identified on the site," Lamey et al. wrote. The mooring system consists of nine legs, grouped 3x3. The chain mooring lines are secured to the seabed with suction piles.

Additionally, the truss spar for this wet tree-only development was selected to mitigate site terrain challenges, simplify riser design and minimize both cost and schedule risk. The Lucius field, along with ExxonMobil's Hadrian South – 8mi from Lucius – tie back to the new spar facility. The Lucius project was brought online only three years after it was sanctioned and five years after its discovery.

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. Lamey et al. said that the hull team and the subsea engineer team worked together to develop concepts for pull tubes to support six future risers that could accommodate up to 15,000psi riser design for future tiebacks.

Big support

The Lucius spar has bragging rights. It

Dockwise's *Mighty Servant I* carried the Lucius spar from Technip's yard in Pori, Finland, to Kiewet Offshore Services in Ingleside, Texas, in 2013, and repeated the same journey for Lucius's sister spar Heidelberg in 2014. Photo from Dockwise.

is often referred to as Anadarko's largest spar built to date by the contractors that worked on the development. It is obvious this massive project would need assistance from the world's largest support vessels.

In 2011, Technip was chosen to provide engineering, construction, and transportation of the Lucius spar hull. A second contract followed in 2012, for the development of the Lucius field. The scope of work included the installation of one flexible flowline, multiple flexible gas lift jumpers; main gas lift and infield umbilicals; subsea distribution units; electrical, fiber optic and hydraulic flying leads. It also called for the design and fabrication of the flexible flowline end termination, fabrication and installation of rigid jumpers, burial of flowlines, flooding and hydro-testing of the flowline system.

Technip's deepwater pipelay vessel *Deep Blue* was used for installation work at the field alongside sister vessel, *Deep Energy*.

Hereema Marine Contractor's then-newbuild *Aegir*'s first job was to install risers and flowlines at the Lucius field, while the deepwater construction vessel (DCV) *Balder* handled the hull and mooring commissioning. HMC's semisubmersible crane vessel *Thalif,* capable of lifting 14,200-tonne (15,600-ton), was tasked with Lucius' topsides installation. The facility weighed an initial 15,000-ton, however, the job was broken into nine lifts, the heaviest of which was 10,250-ton (*OE: October 2013).*

Allseas' massive pipelayer So*litare* was used to install an 18in oil export pipeline, while Saipem's *Casterone* handled the installation of a 20in gas export line. Allseas' *Audacia* installed an oil export pipeline end termination in Keathley Canyon 831.

Engineering and subsea development

Wood Group Mustang provided front-end engineering design, detailed design, procurement support, and engineering support for the fabrication and offshore construction efforts of Lucius' topsides. Wood Group Kenny provided detail design, procurement support, and engineering support for fabrication and offshore construction concerning the subsea facilities.

The main model deck structure for the topsides was built at Kiewit Offshore Services' yard in Ingleside, Texas, along with the temporary work deck, sub cellar module, and stair tower. The topsides' living quarters were fabricated at Beacon Maritime in Orange, Texas, while the compressor modules, production system, and fuel gas system were fabricated at Dolphin Services in Houma, Louisiana.

A view of the 605ft-long, 23,000-ton cylindrical hull of the Lucius spar before it was upended in the Gulf of Mexico in 2013. Photo from Anadarko Petroleum.

Lamey et al. said the spar hull is designed to support the four initial Lucius risers and the two initial Hadrian South risers. Lucius uses four umbilical slots while Hadrian uses one. The risers, Lamey and his co-authors said, have an 8.625in outer diameter with 9300psi (g) design pressure. Each riser pair has a control, chemical umbilical and one gas lift umbilical, the latter will be used for enhanced recovery and flow assurance. The pipeline end manifolds on Lucius come with spare connections for future wells, and come with a removable pigging loop to allow for the tieback of additional structures or fields.

As part of a contract awarded in 2012, FMC Technologies supplied six enhanced horizontal subsea trees rated for 10,000ft water depth and pressures of 10,000psi as well as two production manifolds, and associated tie-in equipment.

Timothy Dean of Anadarko, Paul Haines of Wood Group Kenny, and Marsha Calstrom of EXP Engineering International discuss Lucius' subsea system in OTC paper 26016-MS, saying the field was developed with six initial wells split between two 8in nominal production loops, each with a six-well manifold. An early discovery well is away from the well clusters and Dean et al. said it is daisy-chained into the west manifold flowline loop. Two other delineation wells are produced back to the east manifold with short step out flowlines, which add some flow assurance complexity.

The authors say at the core of the system are 5x2 10,000psi horizontal subsea trees equipped with a subsea choke and a sacrificial flowline isolation valve. A clamp-type flowline connector is used on the tree and for all flowline jumpers.

Next up: Heidelberg

In late June, Anadarko's Heidelberg truss spar set sail from Ingleside, Texas, to its future home at Green Canyon block 859 in the US Gulf of Mexico, some 390mi off the Texas coast.

Heidelberg's topsides, like Lucius, were constructed at the Kiewit yard in Ingleside. 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 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.

The Heidelberg development consists of six production wells, the standalone spar, two drill centers, dual looped 8in flowlines, and 16in oil and gas export lines.

Anadarko operates Heidelberg with 31.5% interest. Its partners include Cobalt (9.375%), Eni (12.5%), ExxonMobil (9.375%), Freeport McMoRan (12.5%), Marubeni (12.75%), and Statoil (12%). **OE**

FURTHER READING

Watch this video of Lucius' topside installation provided by Anadarko. http://www.oedigital.com/oe-media/oe-videos/item/6204-anadarko-lucius-topsides-installation

Archer

Q&A

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In-Depth

By Elaine Maslin

Big data gets even bigger

Big data is not just for the seismic segment. Elaine Maslin takes a look at other areas, such as condition monitoring, where the industry could make significant gains.

Big data is here and there's no stopping it, a speaker at a recent oil conference told the audience.

It is going to get faster and faster, in a lot of areas, he warned, saying that such was the pace of growth it could easily swallow up a lot of resources.

Big data has indeed been growing. Total launched its 2.3 petaflop super computer Pangea in 2013, and the system went on to help analyze seismic data from Total's Kaombo project in Angola in nine days – compared to four and a half months it would have taken before. The same year, Eni launched its latest super computer, with 3.3 petaflop capacity. Earlier this year, Petroleum Geo-Services topped them all and ordered a new 5 petaflop system.

But, these machines have mostly focused on seismic modeling and data interpretation. What about the broader industry?

Awash with data

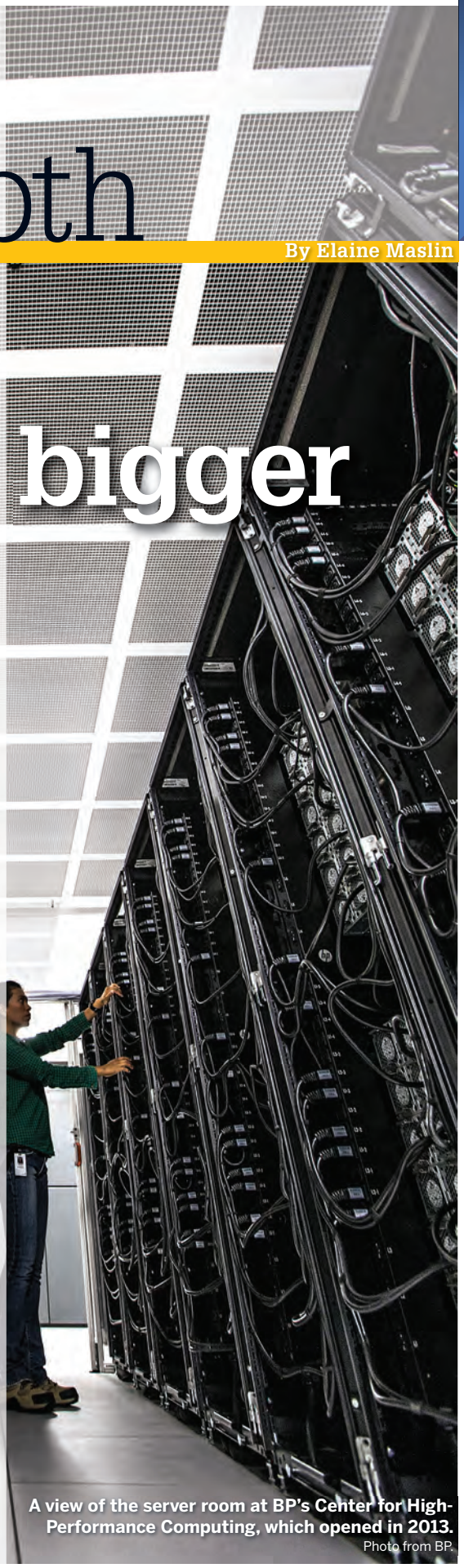
Tor Jakob Ramsøy, director, McKinsey & Co., says while the industry more or less invented big data 30 years ago, to handle seismic modeling, it's "not there" in other areas, such as condition monitoring, where significant gains could be made.

"Information is something this industry is not understanding the value of," he told the Subsea Valley conference in Olso earlier this year. "You understand the assets in the ground – the geology. What is being done with the other information? [The industry is] just imposing more and more data tags, but there is no evidence of how it is making money out of it [the information gathered from these tags].

"The Johan Sverdrup development will have 70,000 data tags, he says, compared to 30,000 on the North Sea platform. Yet, in production and operations departments, there are no data scientists. "The industry is drowning in information, but it doesn't get to those who need to use it," he says.

A lot of data collected is also wasted. According to Ramsøy, some 40% of data is lost because sensors are binary, i.e. they simply show if a parameter is above or below where it should be, which is important data, but doesn't give data for trending to aid decision making or planning. More data is then lost because there's no interface to enable real-time use of analytics.

Further, data management is ad hoc, infrastructure is limited, in terms of high-speed communication links etc., so little is streamed onshore. Forty percent of data generated isn't stored for future use and the remainder is only stored on the



A view of the server room at BP's Center for High-Performance Computing, which opened in 2013. Photo from BP.

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	2012	2013	2014	2015
Shallow (<500m)	74	72	70	26
Deep (500-1500m)	23	19	26	10
Ultradeep (>1500m)	36	35	13	7
Total	**133**	**126**	**109**	**43**
Start of 2015 date comparison	135	125	90	-
	-2	1	19	43

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	8	42.75	2333.28
Deep	12	941.00	2195.00
Ultradeep	40	10,923.75	12,450.00
United States			
Shallow	15	86.3	234
Deep	17	854.27	1230.48
Ultradeep	24	2746.50	3380.00
West Africa			
Shallow	115	3762.45	15,969.22
Deep	38	4622.50	6740.00
Ultradeep	13	1635.00	2460.00
Total	**282**	**25,614.52**	**46,991.98**
(last month)	(290)	(29,463.72)	(51,264.98)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	923	39,108.06	569,033.78
(last month)	(941)	39,572.16)	(571,024.23)
Deep	125	7504.58	109,705.91
(last month)	(134)	(8474.58)	(111,705.91)
Ultradeep	81	15,333.25	31,257.00
(last month)	(87)	(18,502.25)	(34,780.00)
Total	**1129**	**61,945.89**	**709,996.69**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,141	(41,050)
Planned/ possible	25,103	(24,634)
	66,244	(65,684)
8-16in.		
Operational/ installed	81,883	(81,771)
Planned/ possible	49,837	(49,577)
	131,720	(131,348)
>16in.		
Operational/ installed	92,612	(92,399)
Planned/ possible	44,140	(39,926)
	136,752	(132,325)

Production systems worldwide

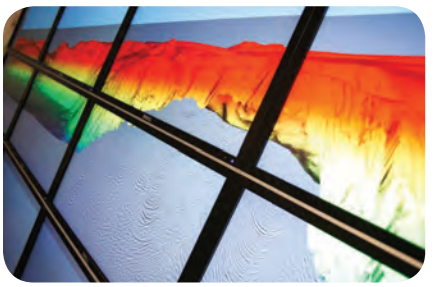
(operational and 2015 onwards)

Floaters		(last month)
Operational	273	(270)
Under development	47	(49)
Planned/possible	320	(321)
	640	(640)
Fixed platforms		
Operational	9232	(9229)
Under development	94	(94)
Planned/possible	1387	(1364)
	10,713	(10,687)
Subsea wells		
Operational	4775	(4749)
Under development	445	(448)
Planned/possible	6474	(6482)
	11,694	(11,679)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	22,904.00	14,233.51	40,181.52	29,444.97	18,549.54	25,954.66	25,295.93
(last month)	(22,904.00)	(14,240.26)	(40,184.72)	(29,309.10)	(18,667.71)	(26,426.20)	(25,670.67)
Deep	481.00	4469.26	4340.71	2371.84	2160.95	4836.00	13,133.29
(last month)	(481.00)	(4469.26)	(4340.71)	(2363.55)	(2222.13)	(5338.11)	(13,900.92)
Ultradeep	2928.44	2342.81	1929.58	3257.38	3812.64	4473.13	8519.40
(last month)	(2928.00)	(2342.81)	(1929.58)	(3257.38)	(5452.10)	(5481.85)	(8519.40)
Total	**26,313.20**	**21,045.58**	**46,451.81**	**35,074.19**	**24,523.13**	**35,263.79**	**45,800.66**

14 July 2015



An example of a high-quality image generated from Total's Pangea supercomputer. Photo from Total.

rig, he says. The end result is that about 0.7% of original data generated is actually used, he estimates.

"It is a big paradox. Everyone is talking about big data, but the industry is fooling around with small data."

Condition monitoring

"We think there is an opportunity in condition monitoring," Ramsøy says, to improve the industry's poor production efficiency record. A single 50,000 b/d platform could save north of US$200 million, according to a study the McKinsey & Co. has undertaken.

The oil and gas industry could learn from the aerospace industry here, Ramsøy says. In aerospace, condition monitoring is used on turbines so that potential failures are seen before they become problems. This changed the way airlines carried out maintenance, and in doing so reduced maintenance by 30%, Ramsøy says. Because airline operators have more information about the performance of the turbines, they're also comfortable with using different turbines, making them engine agnostic, Ramsøy says, again, reducing costs.

Other possibilities include real-time comparison of well characteristics, automated analysis to speed up and improve quality of the seismic decision making, an analytic engine to assess mergers and acquisition prospects.

It isn't always going to be simple. In the oil industry, equipment failure modes come under three categories, he says: wearing out after a period of time or use; infant mortality; random events. Each of these failure modes requires different methodologies for management, which means different data use and handling strategies. But, this shouldn't be a huge hurdle and, while the majors are able to apply the computing power and systems to adopt such techniques, third party data analytics companies have been popping up in Houston and Norway from Silicon Valley, which could help the smaller players in the market.

Predictability

One such company that has been helping to use big data to solve a well-known and common problem in the industry is software firm SAS Institute. David Dozoul, O&G Advisor, SAS Institute, says the firm completed a large project around managing ESP failure rates in 8000ft water depth in the US Gulf of Mexico.

The project's aim was to make sure ESPs operated within their operating envelope, which meant real-time monitoring, using a stream of data from different tags and production, which was compared against analysis of historian data in a live model, which was able to react to the environment the ESP was working in at any particular time.

The result was that the company running the ESPs was able to detect a failure three months ahead of it occurring, enabling them to plan maintenance and order replacement parts and resources, increasing uptime and production.

Dozoul, who described the project at Subsea Valley, says all data available was used and that the data sets didn't need to be perfect – it just needed to be clean. Some 6000 events per day were detected in the project via 17,000 sensors, with 310,000

calculations run and 430,000,000 data points.

The key was being able to model and creating a model that could identify events.

Dozoul says such modeling could also be used to improve 4D seismic data analytics, to help identify the important data and make the analytics faster. "Wherever there is any data, there is a value to analyze so you can model, predict and optimize the process," he says.

Going subsea

Having condition monitoring from day one would also make extending the life of assets far easier, as it makes it easier to prove the condition and therefore ability of the facility to continue operation beyond its design life, and enable preventative maintenance, says Sigurd Hernæs, senior field development engineer, FMC Technologies.

Today, to renew a plan for development and operation on the Norwegian Continental Shelf, which is mandatory when a facility reaches the end of its designed for life, requires design data, installation and operation information, production data, typical corrosion and erosion information, etc., Hernæs says, adding the need to know about any changing specifications, fatigue, damage from trawling, obsolescence, i.e. in electronics." Getting these data for topsides is hard enough. Subsea, the difficulties are even greater.

Giving an example of a manifold that has been installed for decades, he says: "We would want to look at potential corrosion in bends inside pipeline, calculate this theoretically, based on production data, and also assess degradation on polymer – such as Teflon and rubber in seals."

Problems arise when there is missing production data, which is used to estimate corrosion, operational data, showing tie-in forces etc., during installation, and even original design documentation.

FMC Technologies is hoping to make this easier for future projects by introducing a data collector, which collects all data on and going into the subsea system, including data imported from topsides control systems, and multiphase data points, such as leak detectors and apply condition and performance monitoring (CPM). The system could then calculate erosion on continuous basis, Hernæs says, speaking at Subsea Valley. "It would be used quite actively from day one in the life of the field, which means you are far less likely to lose the data," he says. "It could also be applied to calculate the life of a valve on a Xmas tree to predict fatigue issues, as another example."

Big gets bigger

Whichever way you look at it, there's more data and a need for more computing power, but also, crucially, for strategies around what to do with the data and tools or software with which it can be analyzed.

According to tech-focused research firm Technavio, the smart oilfield IT services market 2014-2019 is expected to grow at a CAGR of 5.93% as a result of this growing market. Supercomputers in the oil and gas sector are expected to grow at 7.8% CAGR, according to analysts at IDC.

Faisal Ghaus, Vice President of Technavio says: "Considering the amount of data generation, service providers have come up with sophisticated algorithms and software tools to enhance the decision-making process and optimize productivity, return on investment and net present value of the project."

Big data and big computing is here to stay. OE

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	111	91	20	81%
Jackup	407	310	97	76%
Semisub	160	129	31	80%
Tenders	30	20	10	66%
Total	708	550	158	77%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	36	34	2	94%
Jackup	72	49	23	68%
Semisub	20	18	2	90%
Tenders	N/A	N/A	N/A	N/A
Total	128	101	27	78%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	14	8	6	57%
Jackup	116	81	35	69%
Semisub	34	20	14	58%
Tenders	19	12	7	63%
Total	183	121	62	66%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	24	5	82%
Jackup	9	7	2	77%
Semisub	31	28	3	90%
Tenders	2	2	0	100%
Total	71	61	10	85%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	52	44	8	84%
Semisub	44	41	3	93%
Tenders	N/A	N/A	N/A	N/A
Total	96	85	11	88%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	108	95	13	87%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	113	98	15	86%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	25	21	4	84%
Jackup	23	17	6	73%
Semisub	14	9	5	64%
Tenders	9	6	3	66%
Total	71	53	18	74%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	5	3	2	60%
Jackup	27	17	10	62%
Semisub	13	10	3	76%
Tenders	N/A	N/A	N/A	N/A
Total	45	30	15	66%

Source: InfieldRigs

16 July 2015

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

Challenges and opportunities: Deepwater Intervention

In advance of 2015 Deepwater Intervention Forum held in Galveston, Texas, OE's Managing Editor Audrey Leon discusses the intervention market in the wake of the downturn, and speaks with several forum board members ahead of the show on 11-13 August.

OE: Despite the current downturn in oil prices, forecasts for the subsea intervention market over the next five years are very positive. What is your take on the current market?

Colin Johnston, director, SeaNation: The classic assumption is that intervention will increase during periods of downturn since operators shift focus to existing production. In reality, however, while well service prices reduce to make intervention more attractive, as service companies chase work, the same happens with intervention supply companies. Primarily as competitors in the market place increase due to rig availability growing as a result of lack of exploration and production opportunities. All participants in the subsea well intervention supply segment suffer in an overall market downturn such as we are seeing.

With that said, however, the subsea market is a high-cost project environment and can only be entered into with long-term project planning, cost and management, remaining relatively robust in light of commodity price challenges. In addition, the projected growth of the subsea market provides significant cause for optimism, this growth includes efforts within the subsea industry to improve field recovery, with corresponding technology development to achieve this being a boon to the well intervention business. Finally, and most importantly, the overall age of subsea well assets is increasing and this compounds the growth expected in both well numbers and the need for intervention.

Consequently, the current market suffers a similar downturn to that which others see in the deepwater market but the combination of aging asset and increasing subsea technology development will make for a fairly quick recovery and also long-term healthy growth rate within the subsea well intervention market.

Alex Lawler, drilling & completions engineer, LLOG Exploration: Both the near- and long-term forecasts for the subsea intervention market are promising. In the near term, the focus will be on building a successful work history and demonstrating the capability to execute projects in harsh environments. Longer term, the industry will focus on increasing vessel and equipment inventory to maintain pace with increasing demand, while continuing to increase the applications of intervention equipment.

Helix Energy Solution's Q5000 at its fabrication yard in Singapore, waiting to be towed to the US Gulf of Mexico where it is due to arrive in early August.
Photo by Neil M. Johnston, who is working on the *Terasea Osprey*, which is towing the Q5000.

Robert Keith, Principle Consultant, R.J. Keith & Associates: The intervention market has opportunities to demonstrate its value to operators, especially in this 'depressed' climate, by maintaining, and possibly increasing production on applicable wells.

Rob Hill, Technical Sales Business Development Manager, Aker Solutions: Operators are focused on ways to increase the return on investment of their existing wells in the current market conditions. For example, some operators in the Norwegian Continental Shelf have proven that a scheduled intervention program can pay huge dividends. They have already invested large sums in infrastructure so it makes sense to use intervention programs to increase the recovery rates on those existing fields. New plays are deeper and farther from the shore so they are far more expensive to develop, and the price of oil that would justify the expense of developing those fields is not there right now.

DEEPWATER INTERVENTION FORUM

OE's Deepwater Intervention Forum will be held this 11-13 August 2015, at the Galveston Island Convention Center. For more information, please visit: www.deepwaterintervention.com.

OE: What new innovations will the industry will see in the subsea intervention market in next few years?

Colin: People expect major shifts when it comes to innovations. However, the best innovations are generally improvements over existing methods in relatively small increments. The current market place will see increased emphasis on the efficiency side rather than any major technology developments.

Developments relating to eliminating personnel from the working area in relation to riser and well service equipment will be an important step as will improvements to equipment handling, minimizing crane operations, increasing dual activity emphasis and speeding up the capability for service change out. Overall, the efficiency with which dedicated systems (vessels and services) conduct their business is the priority to put increasing distance between their operations and drilling rigs and is the key area for development in my opinion.

With regards to a longer timeframe step change in the industry, however, I would keep an eye on open water coiled tubing and associated subsea injector head. If this challenge can be cracked then full well servicing can take place without a riser, this truly

would change the subsea well intervention operations market.

Alex: A milestone for the subsea intervention industry will be to successfully deploy an open-water coiled tubing intervention system while maintaining pressure control at a subsea tree. This capability will open an array of new applications for subsea intervention systems.

Robert: Some of the new innovations I hope to see will be better remotely operated vehicle intervention tooling, and improved and smaller control systems.

Rob: Innovation is driven by the needs of the customer and increased oil recovery and cost reduction is what they need right now. Aker Solutions is focused on finding the correct solution to fit the customers need. Lighter well intervention systems for brown field applications will be an area that companies begin to focus on. One example may be using existing technology in new ways to allow an intervention system to be deployed from a vessel of opportunity rather than having to use a mobile offshore drilling unit (MODU) or purpose built intervention vessel.

An emergency disconnect and lower riser package.
Photo from OneSubsea.

We may begin to see lighter systems that can be deployed from vessels of opportunity, but still have the ability to take flow back. Some in the industry may say that deeper and higher pressure systems will be the next new innovations, but with the price of oil where it is currently and where it is projected to be over the next few years, customers will choose to spend their money on increasing recovery from existing wells.

OE: What's the greatest challenge facing the intervention industry?

Colin: The key challenge currently is delivering on efficiency of operations. Vessel providers requested operators to step up with long-term contracts to enable service company commitment and justification for what was required, this has been done in recent years. The next challenge though is demonstrating the daylight in costs between using well intervention vessels versus the alternatives. This shifts the focus back to the service providers to improve operating efficiency either directly by improving

ThoughtStream

Intervention essentials

By John Griffin, Managing Director, FTO Services

Getting the best out of subsea wells has always been important given the significant investment cost. This becomes especially true when field economics come under pressure. Having a subsea well intervention strategy is a key part of maximizing the value from these subsea assets and can often lead to higher returns.

With interventions ranging from downhole diagnostics to troubleshooting seabed equipment the strategy must focus on deploying the appropriate tools for the job. Utilizing purpose-built equipment and systems allows costs to also be appropriate for the job, making interventions more economical.

Collecting well critical data and performing regular well maintenance is common practice on land because it is not so cost prohibitive to do so. Now, these same well critical operations can be performed on deepwater wells at a cost that returns value to the well operator.

These new systems have been brought to the market with an enhanced focus on safety and operations integrity, which enables the intervention activities to be executed in a safe and efficient method. Wellbore interventions that once required a full drilling rig spread can now be performed from a similarly qualified monohull vessel.

The ability to perform the full spectrum of intervention activities on subsea wells in a safe, efficient and economical manner is essential to every deepwater operator's portfolio.■

***John Griffin** – Prior to joining FTO Services as managing director, John Griffin spent 15 years with FMC Technologies where he worked in various engineering and operations management roles associated with subsea installation and intervention services. Griffin serves as the co-chair for the Deepwater Intervention Forum held in Galveston, Texas, and holds a bachelor's degree in mechanical engineering from Texas A&M University.*

mobizilation/demobilization and operation duration or indirectly through increased collaboration and multi-skilling across marine, operations and well service supply.

Finally, the next shift needed in meeting this challenge is the move away from day rate centric comparisons to overall project costs. The combination of efficiency improvements may not make any improvement in dayrate costs for intervention vessels, but it will improve the overall efficiency of a well intervention project. Until this is allowed for in cost comparisons, there will always be the issue of drilling rig/intervention vessel day rate comparisons and this needs to change.

Alex: Though subsea intervention systems have clearly demonstrated the ability to execute early-phase plug and abandonment operations, there is an opportunity to improve methods

Voices

What's the greater challenge for deepwater intervention – technology or best practice?

Neither. The cost of deepwater intervention presents the greatest challenge, with technology and best practices being part of the solution. Today, the total recovery factor from deepwater developments is significantly lower than it is from fixed platform developments because the cost to intervene is so high, making it uneconomical or too risky to do. The development of more efficient, innovative technologies, and setting a standard of best practices to reduce operational, HSE, and financial risks are both needed for successful execution of deepwater intervention.

Bart Joppe, Manager - Integrated Well Abandonment, Baker Hughes

to isolate backside annuli. Tooling and expertise are presently available to access and isolate the A and B annuli, but subsea systems have greater difficulty than traditional MODU's when perforating through multiple strings to access the C annulus and beyond. Prototype systems are presently in development to address this issue. Once proven from a technical and regulatory compliance perspective, these systems will give subsea intervention systems a notable advantage versus MODU's when evaluating plugging and abandonment campaigns.

Robert: The greatest challenge facing the subsea intervention industry is a lack of confidence from operators that may feel that interventions are too: expensive; dangerous; and/or ineffective. It is up to the intervention contractors, in league with positive operators to demonstrate that subsea interventions can produce value, in a safe and efficient way.

Rob: If you look at the Asia Pacific market, the greatest challenge is the size and weight of the equipment. Infrastructure and facilities in the region are aging which makes utilizing intervention equipment a challenge. Also, drilling operations in the region have not declined to a point that would make

While operational efficiency is essential, technology is the greater challenge for deepwater intervention. As the industry continues to push the boundaries of modern technology (HPHT, ultra-deepwater, and/or high flow rates), service providers must not only innovate technically, b ut also meet strict financial requirements.

There is still significant demand for advanced technology, regardless of the current market price for oil and gas. However, in some instances a technology that was feasible and effective at $100+/bbl is no longer relevant in the current cost-constrained environment. Operators and service providers must continue to work together to develop cost efficient and effective technologies, in order to deliver long-term industry growth.

James Cerenzie, Business Development Manager, Oceaneering International

drilling rigs available at a price to allow for intervention via traditional landing string. The region needs lighter well intervention systems that can be deployed from a vessel of opportunity. There are some systems available but the majority of equipment suppliers are focusing on interventions systems that are run from a MODU or purpose-built vessel.

OE: Can cost efficiency and safety be complimentary on intervention jobs?

Colin: The converse of this statement is also equally important in that an unsafe operation will by definition never be efficient. The emphasis on efficiency is a key one for the subsea well intervention market since this is where the overall project cost can be positively impacted. The benefit of such emphasis, i.e. increased automation for handling, removal of personnel from work areas, will translate into improved safety since people are literally being removed from harm's way. The emphasis on multi-skilling should have as its target to reduce the numbers of personnel offshore, again a direct correlation to improved safety if less people are exposed to the more dangerous aspects of operations, namely being offshore in the first place. The key to cost efficiency and safety being complimentary, however, is a shift to overall project cost, to allow demonstration of operating efficiencies, and away from dayrate cost comparisons.

Alex: Efficiency and safety are never mutually exclusive in the oil and gas industry. Both aspects of operations are key drivers for a company's ability to operate. Careful pre-job planning and crew awareness of potential hazards have shown, time and time again, to improve both efficiency and safety.

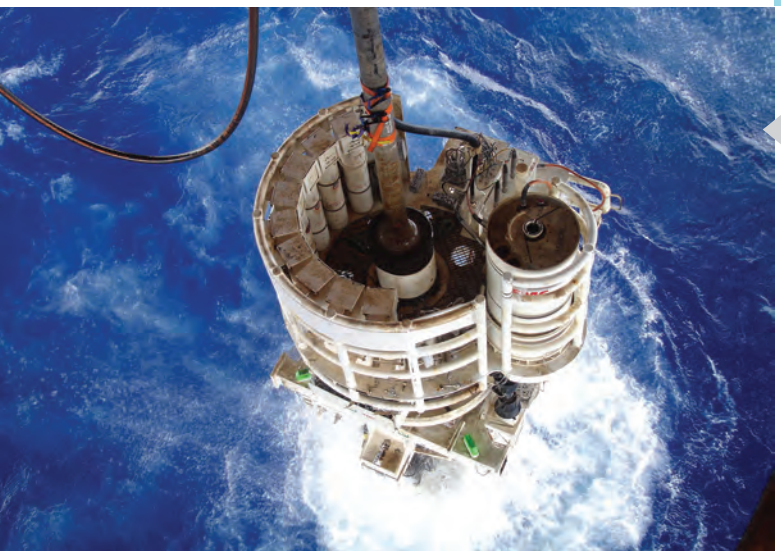
Robert: Cost efficiency and safety are complimentary, and virtually co-dependent as you almost never have one without the other, and any contractor that thinks otherwise will – or already has – gone out of business. Safe operations ultimately are more cost effective that those that incur incidents and accidents; hard lessons learned at a very high cost.

Rob: Safety is always the top priority in this industry, and this is also the case for Aker Solutions. Safe operations are in and of themselves more efficient because there is less time lost for injury or repair. With fewer lost time injuries and repairs the job will be more efficient. This holds true for intervention jobs – If we do not take care of our employees, customers, environment and equipment then future operations become much more expensive. OE

Finding an alternative

Already deployed off Brazil and West Africa, Jerry Lee investigates a new way to intervene on wells — from the drill pipe.

Animated picture of the ocean floor properties of Vallourec. Image from Vallourec.



DPR-2500m 5K System Stack-up at P-XXII rig (Brazil). Photo from FMC Technologies.

Curbing the cost of already expensive offshore drilling and completions programs has to be the mindset of many oil and gas companies, especially after the oil price plummeted. Companies must look into ways to mitigate these costs. One possibility could be the deployment of drill pipe riser intervention systems (DPRIS).

DPRIS is a completions workover riser system that uses an adapter near the surface and pipe similar to drill pipe for constructing a passage to the wellhead. The ruggedness and robustness of the connection allow for numerous makeup and breakouts, while the threading profile results in fast-joint connection and fast tripping speed.

To allow the passage of tools, the inner diameter (ID) of the pipe is optimized. However, the outer diameter (OD) is maintained, allowing the use of normal pipe handling equipment, make and break procedures, and crew. Also, these intervention systems are lighter than typical riser technologies, so they can be used by a larger range of platforms. The system's characteristics make the system convenient to deploy and cost-efficient due to the speed of connections makeup and breakout, which eliminates the need for additional crew and equipment.

Moreover, in sour wells where sulfide stress cracking (SSC) could be an issue, the DPRIS can be delivered with resistance to SSC, as well as other forms of corrosion-assisted cracking. The resistance is incorporated as part of the structure of the steel itself. "We use special chemical compositions of the steel and special processing," says Michael Jellison, senior vice president of engineering, Grant Prideco, part of National Oilwell Varco (NOV) Wellbore Technologies.

Simply put, the drill pipe intervention system is a tube that is upset on the ends (a forging technique that thickens the wall at the tool joint) with highly specialized male and female connections. The major difference between normal drill pipe and drill pipe intervention system is the incorporation of a high-pressure, gas-tight seal. "In general, DPRIS gives you access to the well. It allows you to connect to the well and perform various types of completions or intervention riser functions. It's really a means to get access to the well or to install critical components on top of the well," Jellison says.

Within one system, users have simultaneous access to a completions and intervention system. DPRIS is applicable for use with Xmas trees with fragile studs, Xmas tree and tubing hanger installation, retrieval, testing, hydrate disassociation, downhole valves maintenance, well test, sand removal, and more, says Luiz Fonseca, service manager for subsea services at FMC Technologies.

"Furthermore, the systems are able to operate as early production risers (EPR), providing a system that can perform long-term well testing. In the past, this system represented the sole production system of one basin, working at a floating, drilling, production, storage and offloading (FDPSO) vessel," Fonseca says.

With more than 50 systems operating around the world, DPRIS popularity is gaining momentum.

The first system was developed in the mid-1990s to fulfill a request by Petrobras for a rugged system that could hand numerous makeups and breakouts. The results was the adaptation of drill pipes for gas-tightness.

This first generation drill pipe riser, VAM DPR SR, included a Teflon ring on the shoulder that provided gas-tightness up to 5000psi working pressure. First used offshore Brazil, the system was later brought to offshore Angola, West Africa, in 1999, where Total deployed the system at the Girassol project, via FMC Kongsberg. At Girassol, 33 wells were drilled and DPRIS was deployed 66 times for Xmas tree and tubing hanger installation. During its 14 years of deployment in Angola, the system has been run more than 180 times. The systems are inspected every 3000 hours of use time. And, for the first 12 years of deployment, only 25 connections needed repair, says Vincent Flores, Vallourec global product line manager.

However, despite the success of the first generation DPRIS, it has its limitations, and with industry moving to deeper fields, the system needed to adapt to the changing environment. Thus, 2006 saw the launch of the second generation DPRIS, VAM DPR HP, which could be used at greater depths than the first generation. VAM DPR HP is rated for 10,000psi working pressure. However, the Teflon ring was replaced with a metal-to-metal radial seal design. In 2010, this second generation system was first deployed off Nigeria, West Africa, at another Total-operated project, USAN, mainly for Xmas tree and tubing hanger installation, as well as some well testing and well clean ups. "From 2010 to 2015, there were a total of 75 connections, which needed some repair, after hundreds of runs performed by the system. Each DPRIS can actually be rethreaded several times, thanks to its extended tong lengths. Hence, it allows an enhanced lifespan compared to conventional riser systems," Flores says. The system is still currently in use at USAN and has been deployed in Brazil as well.

However, every technology has limitations and room for improvement. DPRIS is limited by CO_2 in high-pressure, high-temperature (HPHT) conditions, moonpool dimensions, power supply current and nearby deck space required to lay down the hose reel that must be lined up with the moonpool and derrick A-frame. Operators are also concerned about spare parts supply support, the acquisition of missing parts of the spare systems to provide a complete spare system, tool ratings for HPHT scenarios, and the contract model that should be addressed, FMC's Fonseca says. Despites this, interest in the system seems to be on the rise.

Much like the need for the development of the second generation DPRIS, as the industry heads to ultra-deepwater, such as in the Gulf of Mexico (GOM), suppliers must be prepared for the demand of 15,000-20,000psi-rated DPRIS.

"The GOM looks like it's about to turn the corner and start adopting the technology in a more widespread basis. [It] will probably be the most active areas for the technology," Jellison says. "It's starting to pick up fairly significantly. There's lots of interest in it. We've had interest from several of the major operators of deepwater within the last year."

The challenge for DPRIS technology is the high pressure involved for applications in the GOM, and also in the types of tools commonly used. The larger tool types, such as plugs, are common in the GOM but will not fit in current DPRIS configurations. So that's where the next generation is heading — toward larger pipe and tool joint ID's.

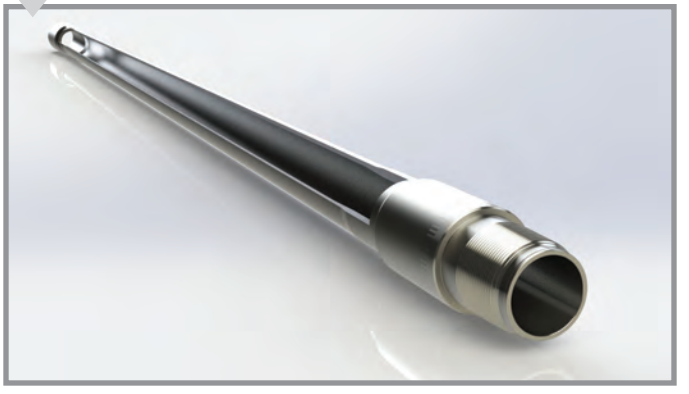
"In the past, NOV has been limited to an OD of 6 5/8in, which limits the size of the tools that can be run inside the pipe, but there's a strong need and desire for larger sizes. As a result, we've been working on an intervention system with a larger OD," Jellison says. Also, due to torsional limits during makeup, there will be a new optimized design for the connection.

Vallourec is addressing the need to widen the ID by using a proprietary grade of steel and changing the connection design. "We have our high-strength materials that are called VM 150 and VM 165. They have 150,000psi and 165,000psi, respectively, as the minimum yield strength. The interest of those grades is that you can increase the performance, via tension and pressure ratings, without having to increase the weight of the wall thickness," Flores says. For the new connection, the design will use new threads and geometry. As a result, the OD of the new product will remain closer to the previous generations, while the ID is enlarged.

Successful deployments in Brazil and West Africa have led to significant improvements and growing confidence in DPRIS technology. With a new market burgeoning in the GOM, DPRIS manufactures could see global interest in this technology rise. OE

VAM DPR SR Connection – properties of Vallourec. Photo from Vallourec.

6 5/8" Grant Prideco Drill Pipe Intervention Riser with XT-M Connections. Photo from NOV.



Shell's 4D optimizes Brazil waterflood project

Shell's second waterflood monitor survey offshore Brazil shows technical success. Jeannie Stell reports.

By all accounts, Shell's first full-field, ocean-bottom, life-of-field 4D seismic system (LoFS) implemented in the operator's BC-10 Parque das Conchas development, offshore Brazil, is a success. There, Shell's waterflood monitor survey shows the enhanced oil-production system is hitting all targets, thanks to 4D imaging.

"At the time of its installation, as part of the BC-10 phase 2 development, this was Brazil's first permanent LoFS network deployed on a full-field scale, and also the deepest deployment of this technology in the world (circa 1800m)," says Shell spokesperson Kayla Macke.

"These challenges proved to be valuable learning opportunities for Shell in dealing with 4D LofS," she says. "Various factors come into play as Shell evaluates and chooses to deploy certain technologies in developing a field. In this particular case, our need to frequently monitor the behavior of the fluids inside the reservoir played a decisive cost-effective role in our decision to install a permanent network of sensors on the ocean floor." However, it's not just the 4D technology that is setting records.

Set the scene

Shell (50% interest) and its partners Petrobras (35%) and ONGC (15%) also set a record with the deepwater, Campos Basin, Parque das Conchas (BC-10) development by employing the first subsea installation tie back to a centrally located, turret-moored, FPSO, stationed in 1789m water depth. BC-10 is also the first of its kind, based on subsea oil and gas separation and subsea pumping.

The development includes the first application of steel tube hydraulic and multi-circuit high power umbilicals that deliver power to 1500hp pumps on the seabed, and is the first application of lazy wave steel riser technology on a turret moored FPSO.

Shel's BC-10 development produces heavy oil, with densities ranging from 16°-24° API gravity, from four small-to-medium low-pressure, dispersed reservoirs, which requires water injection to maintain pressures.

The field's the reservoir, consisting of unconsolidated turbidite sands with an average thickness of 25m, is relatively shallow by virtue of its top lying just 1200m below the mudline.

The FPSO *Espirito Santo*, a converted tanker leased by Shell and its field partners from owner and builder SBM Offshore, is the workhorse here, and is able to produce up to 100,000 b/d of oil and inject up to 75,000 b/d of water.

The field was developed with 22 wells with more than 20km of reservoir completions, 10 subsea pumps providing around 15,000hp of lift capacity, and

SBM Offshore's *Espirito Santo* FPSO can produce up to 100,000 bo/d and inject up to 75,000 b/d of water. Photo from Shell.

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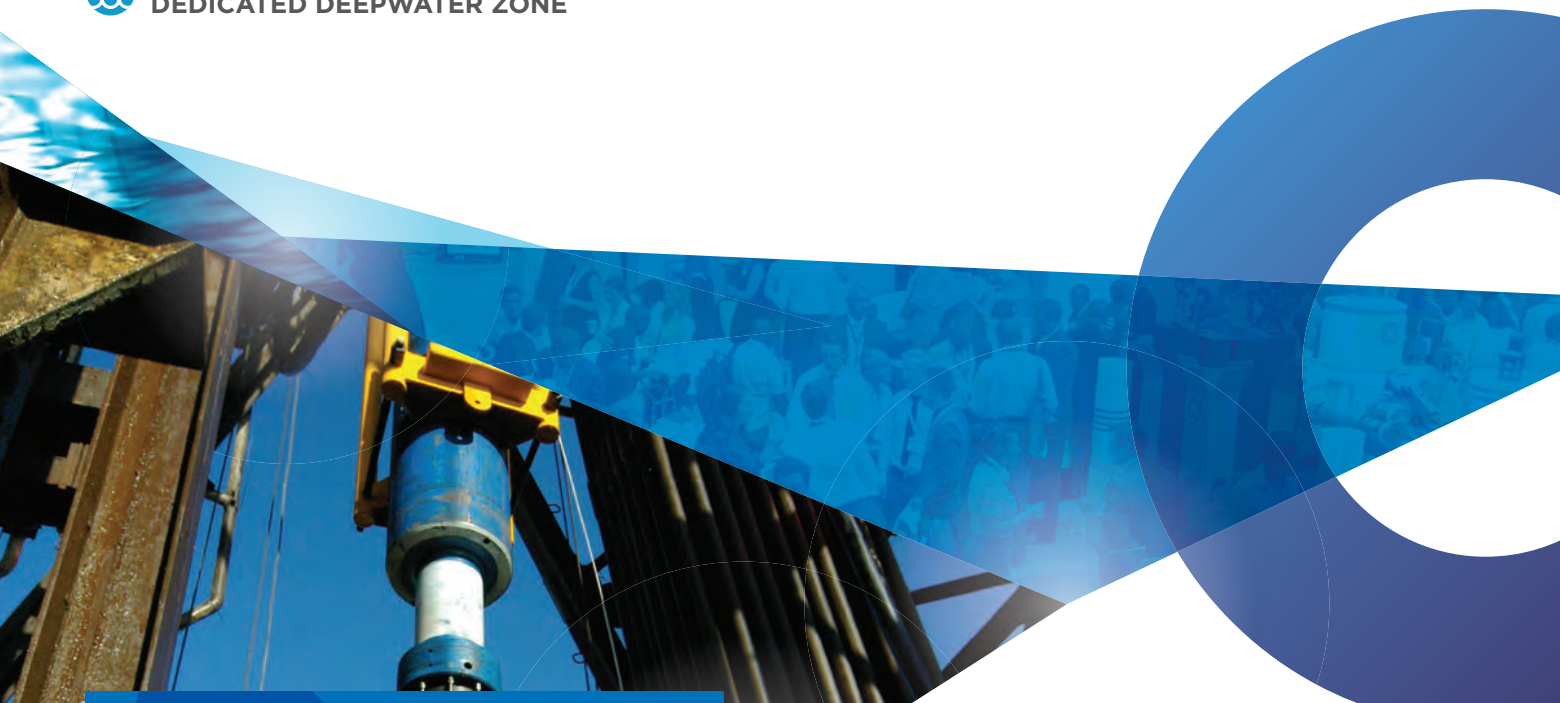

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Cost-effective 4D

The seismic program includes 100km of untrenched ocean-bottom cable in 14 lines spaced 400m cross line and four component sensors placed 100m in-line covering the entire reservoir and extending over the bounding faults to the west. Trenching for the cable lines and sensors was unnecessary due to the depth of the lines, but nonetheless the cables were carefully set into place to ensure longevity.

"The network of seismic sensors installed on the ocean floor is expected to remain in place for as long as Shell continues to produce from that field," Macke says.

The seismic cables are connected via 11km backbone cables to the existing umbilical termination assembly, which supplies power to the subsea LoFS system. Spare fiber-optics fibers in the existing umbilical are utilized to transmit data to the topsides and to provide control communications from topsides to subsea. The topside system includes a cabinet of power supplies in the FPSO turret, a dual-rack cabinet for the operating system and data storage in the main equipment room. The seismic system can be operated from either the FPSO or from Houston-based remote operations via a dedicated satellite link.

Because low-cost seismic is a crucial element to manage the costs of frequently repeated surveys for the 4D data generation, Shell used a fit-for-purpose seismic vessel to tow a single source comprised of three sub arrays of 2450cu in, with source points acquired on a 50x50m grid.

Overall, the 4D enabled early observations that provided critical information to Shell, which led to optimized well rates during the early life of the BC-10 field.

Navigation data from the shooting vessel are available shortly after completing a sail line. The data are sent via satellite to the recording system where they are merged with the seismic data. The first monitor survey was acquired within 30 days and achieved good repeatability with 93% of shots within 5m of pre-plots.

The base seismic survey was completed in November 2013 prior to the first water injection. After the water injection in 1Q 2014, the first seismic monitor survey was undertaken and completed in June 2014.

Time-lapse 4D seismic data was utilized, and was required for two reasons. First, the operator wanted to optimize the waterflood project by measuring the changes in fluid saturations and pressures. Secondly, it needed to monitor the effectiveness of the water injection process.

Data processing

Shell's Marine Imaging Group drew on prior 4D-processing experience that it developed for ocean-bottom node surveys, with additional pre-processing, including 3-component geophone orientation. The team was able to accomplish the rapid delivery of quick-look 4D seismic volumes to the operation and development teams only three weeks after completion of the monitor survey acquisitions.

The high fold and good repeatability of the LoFS data helped reduce in-field noise to acceptable levels. The in-field noise was from rig activities and some seismic interference was generated due to another survey undertaken during the waterflood monitor.

Pressure inverted echo sounder instruments were converted to connect directly to the LoFS system for continuous power and data transmission and to provide good water velocity and tidal depth data for deepwater statics solutions.

Quick-look results

Despite the short duration between the start of the water injection and the first seismic monitor survey, significant information was obtained that confirmed that there was no out-of-zone events and that water was injected along the entire length of all laterals. The seismic confirmed the location of early water production in two wells and that no water fingering from injectors to producers was observed.

Specifically, long, narrow hardening signatures along each injector indicated the successful injection of water along the entire length of the more than 1000m laterals. Also, the 4D survey showed that two of the producers with the highest offtake rates exhibited strong softening anomalies caused by gas saturations of 2-3% due to flowing bottomhole pressures below bubble point.

At a Glance: Shell's BC-10 key facts

Location:	Campos Basin, Brazil
Depth:	~1780m
Interests:	Shell 50% (Shell operated), ONGC 27%, Qatar Petroleum International 23%
Fields:	Ostra, Abalone, Argonauta
FPSO design capacity:	100 kb/d and 50 mscf/d of natural gas
Key contractors:	BDFT (JV between SBM/MISC), Subsea 7, FMC Technologies, V&M do Brasil, Oceaneering, Transocean/Global Santa Fe, Halliburton

Conclusion

The 4D seismic endeavor enabled early observations that provided critical information to Shell, which led to optimized well-production rates during the early life of the field. The data confirmed the absence of water fingering, which increased confidence for the continued similar and enhanced operation of the field, and allowed higher offtake rates of the relatively viscous oil while still maintaining good reservoir sweep efficiency. These observations supported the decision to operate the field at higher rates, which provided early economic benefits.

Shell reports that, beyond 4D, the baseline data will be integrated with new directional deep-reading resistivity logs from the lateral sections, as well as being integrated with inversions for reservoir properties, to build new static and dynamic models. Broadband processing will be used to aid understanding of the overburden and analyses of the reservoir depth. Passive seismic recordings will be the subject of further internal research efforts.

When asked if this technology will be deployed at similar fields, Macke says: "The LoF 4D was a cost-effective solution for BC-10, and our learnings from Brazil can be used elsewhere, if deemed appropriate for development plays in other regions." OE

Based on a Shell interview and Shell's whitepaper, OTC-25803-MS.

RCD rig up on the BOP stack.
Photos from Weatherford.

Integrating MPD into existing rig systems

Revamping older offshore rigs with modern technology positions them for more efficient and safer drilling to target depth. Weatherford's James Onifade and Turkish Petroleum Oilfield Services' Yilmaz Kum and Benhur Sahin explain.

In the current low commodity price climate, avoiding non-productive time (NPT) is increasingly important, especially when drilling offshore to recover hard-to-reach resources. Many scenarios can prompt a decision to shut in or kill a well due to common pressure and safety concerns. However, NPT is avoidable with the introduction of modern, automated-control systems into the equipment configuration and operations of a rig, which enables precise navigation to drill more safely and efficiently.

Case study: Pressure challenges in narrow-margin well

On behalf of operator Turkish Petroleum Corp. (TP), Turkish Petroleum Oilfield Services (TPOFS) needed to drill through narrow margins within the confines of the pore and fracture pressures in the Mediterranean Sea using a jackup drilling rig built in 1988. The operator knew that the well could not be drilled by conventional methodologies. The major challenge was to manage the bottomhole pressure (BHP) within close tolerance without jeopardizing the safety of personnel, environment or equipment.

Weatherford's managed pressure drilling (MPD) system was chosen as the tool that would enable the drilling operation to "walk the line" between pore and fracture pressures while maintaining the BHP within acceptable limits. The goal of integrating the MPD system into the existing rig system was to more precisely control the annular pressure profile throughout the wellbore and to maintain wellbore stability, especially during connections and other pump-off events.

Equipment installation

The MPD components had to be integrated into the layout of the existing rig system in a manner that maintained optimum operations without adding confusion to the drillers' routine. To solve that challenge, training was provided to ensure that the rig crew was comfortable with the new equipment features and understood how MPD worked in conjunction with their standard equipment makeup.

- **Rotating control device (RCD)** – This device, installed on top of the rig's annular blowout preventer, creates a closed-loop system with returns directed from the well to the MPD choke manifold through connected flow lines, as opposed to open-to-atmosphere techniques. The RCD contains a bearing assembly, which is locked in place during operations. While the drill pipe rotates, a passive seal is maintained around the pipe via two sealing elements. This enhancement enables accurate measurement of flow-out parameters and provides protection for the rig personnel on the surface.
- **Automated MPD control manifold** – Two fully automated drilling chokes, along with a Coriolis mass flowmeter and a hydraulic power unit, manipulate the choke position. For this operation, the choke manifold was spotted on the starboard side of the cantilever deck and was connected to the RCD with a 6in co-flex main flowline hose. Throughout the drilling operation, the MPD system software recorded critical real-time data, including the flow in and out of the well, fluid density, temperature and volumetric flow rate.

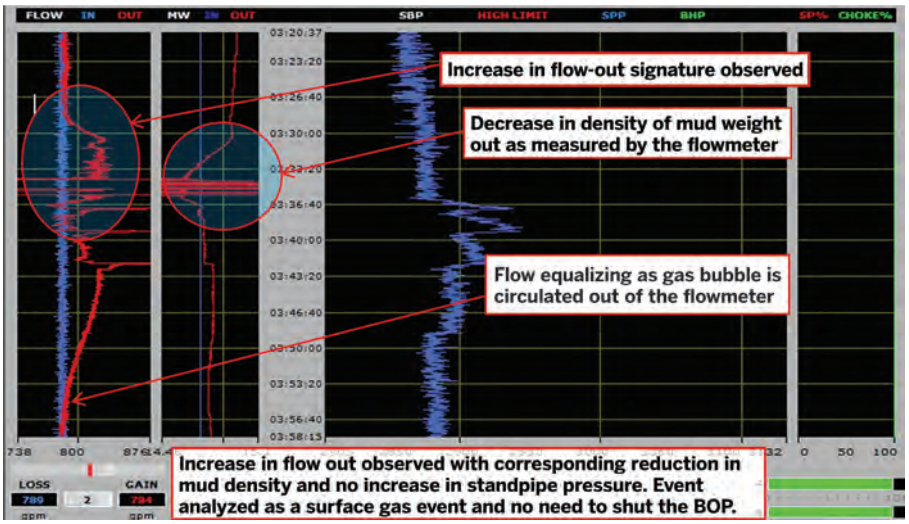
With the bearing assembly installed in the RCD, an additional auxiliary line was put in place to ensure that the trip tank could also be used for flow-checking the well – allowing flow across the well, through the MPD manifold flowmeter, and back to the trip tank.

Drilling operations

Once tested and calibrated, the MPD system was used to drill and enlarge four distinct hole sections, ranging from 17.5in to 8.5in open hole sizes. Each hole section presented unique challenges, including influx and loss events, the need to maintain constant BHP during connections, and the placement of a heavy mud cap while stripping the drillstring out of hole and background gas from the formation.

During operations, many of the innovative MPD features helped alleviate adverse conditions. For example, the annular pressure control mode of MPD system automatically displaced the heavy mud cap at specific depths, which maintained static overbalance when the drillstring was out of the hole. An influx of water into the wellbore was detected early enough to exercise the necessary control and safe stripping back to the bottom and to circulate the water out of the wellbore.

Also, the automated MPD system clearly identified a "gas at surface" event and eliminated the need to shut in the well altogether. Using conventional drilling methods, an increase in flow out could have been mistakenly interpreted as a kick, leading the driller to shut the well in unnecessarily.



An automated MPD control system identified a "gas at surface" event. This screenshot shows an increase in flow out of the well (first column) with a corresponding decrease in mud density (second column).

The MPD system was also used in freeing a differentially stuck drillstring. While drilling the 8.5in section with a mud weight of 16.5ppg, the MPD system applied roughly 550psi SBP to maintain an ECD of 18ppg. After an unsuccessful jarring operation, the MPD system reduced the ECD below the formation pore pressure in a matter of seconds. The string was freed and the induced influx was safely circulated out of the wellbore in a controlled manner.

The MPD system also provided early identification of pump washouts. By monitoring flow out and using the loss detection capability of the Coriolis flowmeter, pump washouts were correctly identified before reductions in SPP were even observed.

Overview of MPD value

This case study demonstrates the successful incorporation of an MPD system into an existing, older rig system with minimal disruption to rig operations and equipment. The advanced equipment capabilities of the MPD system included early detection of kick and loss, identification of surface gas events, placement and displacement of heavy mud cap, dynamic pore pressure and leakoff testing, and maintaining constant BHP during drilling and connections.

Throughout the drilling process, the system provided clear trends and crucial information that enhanced operational efficiency and safety. Ultimately, the operator was able to drill effectively to the target depth, thanks to the proven ability of the MPD system to "walk the line" between the pore and fracture pressure limits. OE

James Onifade *is a project engineer respsonsible for planning, executing and ensuring a safe and efficient application of MPD technology. He holds a bachelor's degree in mechanical engineering, a master's degree in mechanical engineering from the University of Portsmouth and a master's degree in oil and gas engineering from Robert Gordon University, Aberdeen. He is a Chattered Engineer with the Institute of Mechanical Engineers IMechE.*

Yılmaz Kum *has over 12 years' deepwater, shallow water and land rig drilling operations experience as a drilling supervisor and engineer. He has bachelor's degree in petroleum engineering from Istanbul Technical University. Currently, he is an operations manager, responsible for drilling and completions in Iraq.*

Benhur Sahin *has seven years of experience in the oil and gas industry. He has professional experience in drilling fluids and drilling engineering disciplines. He has a bachelor's degree in petroleum engineering from the Istanbul Technical University, and is currently studying for his master's degree in software engineering at Middle East Technical University.*

Designing for tight spaces

Designing a tightly packed, complex turret system is one thing. Designing so it can be built and then maintained without causing hiccups is another. Carlo Pellegrino of Italy's RINA Services explains.

More and more offshore oil and gas solutions tend to be free-swinging floating units as asset owners seek flexibility and solutions to exploit remote and deepwater offshore fields.

These vessels must be moored so they can rotate around a turret system into which all the risers and umbilicals connect.

Turret technology is well-understood and operators have considerable in-service experience of them. However, as units operate in deeper waters, there is a greater requirement for larger numbers of heavier risers and umbilicals to pass through the turret — an already restricted space.

While space congestion can be resolved at a pure design level, with 3D modeling capable of optimizing spaces and preventing physical clashes, such solutions might not take into account how easy and practical it is to build, install and test the turret. A good design, which will work well in service, could be slow, costly and difficult to fabricate, install and test.

Italian classification society RINA is advocating including "constructability" as a design criteria. Constructability is the ease and efficiency of fabricating, installing and testing the main process piping lines, subject to the design and integrity requirements of the installation.

The philosophy behind constructability is to ensure that each system, pipeline and component can be installed and tested in a scheduled sequence without

interfering with other systems, pipelines and components.

Getting constructability wrong can have dramatic consequences for schedules, costs, quality of installations, the ability to remediate defects or construction errors, safety and possibly cause the need to dismantle mechanically completed systems to allow completion, testing or repair of other systems.

For example, in some industry situations, the flange sealing face of large components such as valves were damaged during installation due to poor access or inadequate lifting facilities. As a consequence, the following helium leak test failed and the only solution was to rework the flange face by machining. That meant that, in the restricted space, the installation of the milling machine necessitated a large section of the adjoining piping and related instrumentation to be dismantled. The high-pressure leak test failure introduced an unwanted safety issue, delay to the schedule, and an overall lower quality outcome because brand new items had to be repaired before startup.

FSRU *Toscana*. Photos from RINA.

Striking a balance

There is a balance to be struck between simplicity of design, efficiency of operation, and ease of building and installation.

This can be achieved by running a constructability study in parallel with the design activities, so that constructability is considered at each phase of detailed design. This process will cover turret fabrication, commissioning and testing, and lead to better overall time keeping, lower costs and higher quality products for the project with a better construction safety record.

Constructability studies should include:

- Challenging each proposal at the design stage in terms of fabrication, installation and testing.
- Identifying fabrication, installation and testing methods and techniques to improve the construction sequence and avoid any need for reworking.
- Detailing the construction sequence to give the best possible option for installing components and limiting conflicts of disciplines and the need for rework.
- Identifying and quantifying the minimum requirements of resources such as specialized workmanship, equipment, materials and consumables.
- Verifying the availability of resources to meet the schedule and drafting contingency plans as applicable.

Embedding constructability into the design process requires the use of 3D and 4D modeling tools, such as Autodesk Navisworks and 4D-BIM. 3D modeling software can be fed with information related to both physical clashes and the space allowances necessary for installation and maintenance operations and, with the addition of 4D modeling, scheduling clashes.

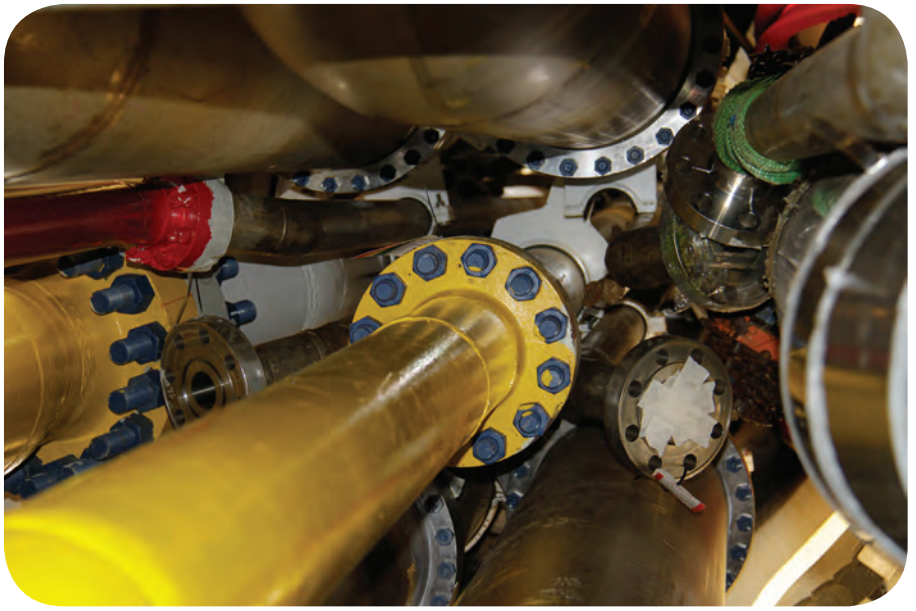
Design criteria

Each project also requires its own criteria, such as deck-framing plans designed and placed to support components in place as well as to temporarily support them during installation and replacement, or suitable spaces between components to allow for installation, replacement and maintenance. Another criteria could be that lifting facilities, covering the external and internal areas of the turret, are provided and drop-pick areas are accessible to all lifting equipment. Detailed design should focus on items necessary for easy installation by avoiding the need for extra construction resources, such as highly specialized workmanship or extra lifting equipment.

Inspection strategies and methods must be built into the design criteria. It is useless to build a turret if technicians cannot access it in order to test and inspect it later.

Further detailed design issues that should be built into the 3D modeling process are:

- Ensure components, including valves, manifolds and large piping spools, are equipped with permanent or removable legs, pedestals, saddles and lifting points or lugs suitable to lift, slide, balance and level as necessary the components during installation, positioning and fitting-up with adjoining piping.
- Ensure deck areas are equipped with lifting facilities capable of linear overhead handling and maneuvering heavy components from the drop-pick area to directly over the support or saddle.
- Ensure decks are equipped with floor



Inside view of a turret. Photo from RINA.

rails to slide heavy components into position.

- As much as possible, replace conventional flanged connections with hub or clamp joints such as the G-lock type. This eliminates the issue of flange bolt-holes matching and assures easy assembly. Hub or clamp joints also provide reduced dimensions and weight when compared with an equivalent rating in accordance with the American Society of Mechanical Engineers or American Petroleum Institute.
- Design hub or clamp joints to include a hub spacer, adapter or reducer. The three-piece joint provides a suitable break point via the removal of the hub spacer to allow hydrostatic testing — particularly nitrogen or helium leak testing without any need to move or remove the flanged joints from the set position. This solution greatly enhances leak testing scheduling and safety, and improves operations and maintenance.
- Select the long welding neck option for conventional flanged joints, hub or clamp joints and piping fittings such as elbows, T-shapes and reducers. This provides an easy fit up and welding operations, including thickness and internal diameter consistency, correct root alignment, welding access and, consequently, reduced repair rates. The option facilitates execution and improves reliability of non-destructive testing inspections.

While some of these issues might seem obvious in standard practice, the reality is that constructability objectives are not routinely included in the piping design scope. For example, the design of the piping and valves supports is usually led by the stress analysis results without considering any need for supports to assist component installation and related flanged joint execution. In other words, designers think about the end they want to achieve, not how the builders and testers have to get there.

Fabrication, installation and testing

The selection of fabrication, installation and testing methods and procedures should be focused on easy installation to avoid the need for highly specialized workmanship, extra lifting equipment and for in-field construction, adjustment or reworking.

Some points to consider:

- Maximize pre-fabrication and pre-inspection in areas where interference with other activities can be avoided and where any re-working is not on the schedule's critical path.
- Select piping spool geometry and relevant field joints to facilitate installation rather than to optimize prefabrication or easy transportation.
- Ensure dimensional inspection is accurate, especially those dimensions that affect fit-up and joining on site, eg. piping flange and fitting orientation. Laser-aided dimensional checking should be used in conjunction with 3D modeling.
- Complete piping and components testing as far as possible in the workshop to minimize in-field testing and to reduce the risk of failure during testing performed on completed systems.
- Ensure piping and components are thoroughly cleaned, dried and preserved internally.
- Ensure painting, coating, surface chemical cleaning or passivation are completed and joining areas are left in the best possible status to be completed at the site after installation.
- Protect painted, coated, chemically cleaned or passivated surfaces to avoid damage, degradation and touch-up and re-working after installation.
- Sequence installation to avoid or minimize mounting-dismounting as well as damage to already-installed materials and components. Heavy and large components should be installed first.
- Exotic materials that need to be segregated from ferric materials are installed when the installation of carbon-steel materials is completed.
- Cable trays, cables and instrumentation should only be installed when other major construction works are completed or if pre-installed should be suitably protected.
- Use enhanced non-destructive testing (NDT) methods and techniques for volumetric testing of field-weld joints in lieu of radiographic or gamma-graphic testing to improve safety, testing reliability and scheduling. The NDT methods to be considered are semi-automated phased array and time-of-flight diffraction used as single methods or in combination, depending on material, joint geometry and dimensions.

Attention to detail

Constructability is a simple concept to grasp, but a difficult one to implement well, which is why it is too often not given enough priority. It requires meticulous attention to practical details at every stage of the project. That, of course, takes time, money and resources. But it is an investment that pays off by delivering a better turret in a shorter time at a lower overall cost. **OE**

Carlo Pellegrino has 35 years of experience in the oil, gas and energy industry covering QA and QC management positions within several major projects, including responsibility for material reliability and asset integrity particularly with regards to sensitive disciplines like welding, non-destructive testing and materials.

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Innovation – in all its forms

Standardization has been high on the agenda at the Underwater Technology Conference (UTC) in Bergen for the past two years. This year, the focus was "innovating for the next wave." Elaine Maslin reports on innovations discussed and on show.

Innovation can take many forms, said Simon Davies, manager, technology management, Statoil, while introducing the first panel session during this year's UTC.

One such form is learning from and leveraging expertise from other industries and both were evident at UTC. Aker Solutions' latest subsea control module, Vector 6, was developed with expertise from a telecommunications business and its new electronic actuator was developed with the help of an automotive industry-focused firm.

Shell is using non-oil and business expertise a different way. It has launched a new program – Shell TechWorks – to bring in innovation from outside the exploration business, its head of program management, Julie Ferland told UTC. She says engineering and program managers from outside the oil and gas industry have been recruited into the program to use a systems engineering approach to collaborate directly with other businesses to solve the oil industry's challenges.

Ferland herself comes from outside the industry. A gas turbine engineer in the navy, she's also been a saturation diver and, most recently, worked at AUV firm Hydroid, developing the Remus AUV.

"We are bringing a perspective from aerospace and other industries to see and understand what other technologies can be brought in to the industry and what minor changes need to be made to make it meet the needs in the industry," she says. Interestingly, the group's first innovation was around how they found information from within Shell in order to carry out their first step, which was to delve into the business to create a systems model and to define what specific goals were in order to define them to the market.

Hervé Valla Photo from Aker Solutions.

For Hervé Valla, chief technical officer, Aker Solutions, looking at the bigger picture – problems on a systems level – is a key to innovation, instead of operating in silos, which the industry has a tendency to do.

Aker Solutions is doing this with its subsea alliance with Baker Hughes, he says, removing the "false barrier" separating the well and subsea. One of their first innovations, PowerJump (*OE: NCE Subsea supplement 2015*) is a system innovation using existing components, he says. In less than a year, components have already been qualified and a prototype is being built.

But, he also suggests technology development around creating families of products, which can be adapted, rather than reinvented, for different situations, but built from the same core components, such as the firm's new subsea control module, Vector 6, which has a standard chassis, but its software means it can be modified to meet deployment requirements. What is interesting about Vector 6, is that it was developed by a team that had been brought into Aker Solutions through the acquisition of the telecommunications business in 2012. "They came with a completely different mindset and challenged us a lot," Valla says.

Aker Solutions' electronic actuator. Photo from Aker Solutions.

Aker Solutions worked with another non-oil and gas core firm Devotek to develop a subsea electric actuator, as part of its work on the Åsgard and Ormen Lange subsea compression projects. Devotek, which is traditionally more involved in the automotive sector, has made a solution smaller and lighter than any other on the market, Valla says. It is now fully tested and qualified and being offered in tenders.

The 83cm high (smaller than a Dyson vacuum cleaner), 85kg in the water, subsea electric actuator, qualified for 4000m water depth and -5 to 55°C operating temperatures, has been designed for a 25-year running, with a dual motor and gear oil system, for barrier protection and lubrication, has a metal pressure compensator with condition monitoring. Maximum torque output is 2700nm with 50,000 cycle lifetime at 1800nm nominal torque.

Jupiter's subsea inline contamination monitor.
Photo from Zetechnics.

Jupiter

UK-based Zetechnics has also drawn on wider industry technology to help offer a new solution. Tim Overfield, the firm's managing director, said a conversation with an ROV operator about monitoring hydraulic fluid condition and another with a hydraulic fluid monitoring technology firm, led to their Jupiter trademarked subsea in line contamination monitor (ICM). Units sold fast after it was shown at Subsea Expo in Aberdeen earlier this year and the sales continued at UTC.

The 4000m deepwater-rated ICM is a permanent hydraulic fluid (mineral oil or synthetic oil-based with a water glycol version available) monitoring tool, which enables operators to identify early when hydraulic fluid has any contamination in it so that maintenance can be carried out before it causes a problem and at a time that suits. The ICM unit measures hydraulic fluid for particulate and water contamination. The 120mm-diameter, 200mm-long, titanium encased 2.3kg in water ICM, which can run periodically or continually, needs just 24v and stores up to 4000 sample tests to its memory.

Zetechtics also had its latest subsea control unit, Jupiter 2, on show at UTC. Launched earlier this year, it is the latest version of the firm's first control unit, deployed first in 1998. Jupiter 2 has been launched as a family of units, which can be adapted according to client requirements. Its innovation is bringing what in the past has been two separate units in to one, enabling control of small but also very powerful functions, from 12l/min to 160l/min from one unit, making it a flexible, multipurpose unit. Jupiter systems have always exhibited very high dependability with that very first unit recently overhauled and redeployed; it had no damage to the electronics, just needed hydraulic valves replacing and the software upgrading.

Overfield says the industry would benefit from more standardization, which it has historically tried to achieve, but not quite fully managed, as well as using technologies from other industries, but only where they are found to be high-enough quality.

Cathx

Founded in 2009, and based in Kildare, Ireland, Cathx Ocean presented its subsea optical measurement capabilities in a UTC technical session. CTO Michael Flynn outlined a case study from the North Sea, which showed how the firm's tools and techniques were able to provide high resolution images of a pipeline section.

Traditional techniques, such as HD video and multi-beam sonar, have limited resolution, he says. HD video stills, however provide better resolution. If laser profiling can be used in combination with HD stills, high resolution images can be created and a 3D point cloud. Each pixel on the image can be calibrated as X, Y, Z points thanks to linking the camera with the laser and using basic trigonometry, he says. At 5m distance, you can get 2mm resolution on the point cloud data set.

With this technique, the difficulty comes when you want to shoot images of laser profiles, which are best seen in darkness, while you need intense bursts of light for the HD stills. Cathx solved this with sequencing. For example, in variable turbidity, 3D laser data is sequenced with co-registered still images.

Halfwave

Norway-based Halfwave launched its ARTEMIS subsea pipeline and riser inspection tool, based on acoustic resonance technology (ART) developed by Det Norske Veritas (DNV, now part of DNV GL) over the last 20 years.

ART is an ultra-wideband inspection technology that exploits the phenomenon of half-wave resonance. A sending transducer transmits a broad-band acoustic signal toward a metal structure of interest. The signal spreads in the structure, exciting half-wave resonances. The response of the structure transmits a characteristic signal which is detected by a receiving transmitter, with the results then analyzed revealing resonance peak frequencies, from which the structure's thickness can estimated.

ARTEMIS was developed to inspect subsea pipeline and riser integrity from the outside and through coatings using ART. It is deployed by ROV and performs a 360° scan, using ART, through pipeline and riser coatings. Halfwave, which is owned by private equity house Energy Ventures, DNV GL, Chevron and certain staff, says it has qualified the technology with one operator.

ARTEMIS follows hot on the heels of Halfwave's ART Scan, an in line internal pipeline scanner, launched earlier this year. OE

Gullfaks South multiphase compressor before load out. Photo by Harald Pettersen - Statoil ASA

Boosting in the deep

The rewards on offer from subsea boosting technology were spelled out at the MCE Deepwater Developmment Conference in London this spring by Arne B. Olsen, sales director, pumps and subsea processing at OneSubsea. Meg Chesshyre reports.

Subsea pumping improves field economics by reducing backpressure on the reservoir, increasing well flow rates and total recoverable reserves, explains Arne B. Olsen, sales director, pumps and subsea processing at OneSubsea. Boosting improves flow assurance by increasing velocity in pipelines, increasing temperature, and stabilizing production.

"OneSubsea has been operating in the subsea processing arena longer than any other company in the world, and records today more than 15 years MTTF (mean time to failure) of our pumps," he says, with the firm's technology development facilitated by the company's ability to invest in large realistic test infrastructure.

However, the subsea booster market has been slow to develop and there are a limited number of projects out there, Olsen admits.

The vision

Subsea boosting is still being described a new technology, despite being around now for more than 20 years. The original vision for subsea multiphase pumps was to create a technology that could extend satellite development from fixed platforms out to about 50km. Framo's first multiphase test rig was in place as early as 1987, at the company's facility just south of Bergen. Here, the firm selected and tested the helicon-axial pump principle to be used.

The evolution of multiphase pumps from OneSubsea's successful collaboration with Shell on the Draugen field in the Norwegian sector of the North Sea dates back to 1994. That marked the delivery of the first commercial subsea multiphase pump (650 kW), in 270m water depth on a 9km tie back. This was followed by Statoil's courageous decision to install subsea electrical pumps on the Lufeng field in the South China Sea in 1997. These pumped some 42 MMbo from 1997-2011.

The first true subsea multiphase pump was installed in 2000 at ExxonMobil's Topacio field in Equatorial Guinea, and has been in operation for more than 50,000 hours since.

The first subsea water injection pump was installed at the Troll pilot, in the Norwegian sector of the North Sea, in 2001, and the first subsea seawater injection system at Columba E, in the UK North Sea, for CNR in 2006.

The deepest, longest tie back and highest design pressure was installed in 2011, for the Chevron-operated, 2100m (7200ft) water depth Jack/St. Malo development in the US Gulf of Mexico. First oil from Jack/St. Malo was last year. OneSubsea supplied the production and processing systems for the project, including 12, 15,000psi subsea wellhead trees, production controls, four manifolds and associated connection systems, engineering and project management. Through one of its predecessor companies, the firm also supplied three pump stations, three subsea pump control modules and associated and instrumentation equipment. The pump systems, which are comprised of three megawatt single phase pumps, are remarkable for their combination of 13,000psi design pressure and installed water depth.

OneSubsea also delivered the largest differential pressure systems to Total's 1400m deep GirRI project (130 bar differential pressure) offshore Angola in 4Q 2014.

One the key drivers for the technology has been increasing water depths, with projects, such as Jack/St. Malo, reaching down to 3000m, with a design pressure at 15,000psi, to meet requirements in the Gulf of Mexico and differential pressure evolution at 140 bar.

Wet gas compression

The most recent highlight for OneSubesa, however, has been the delivery in March this year of the world's first subsea multiphase compressor to Statoil for the Gullfaks South field in the North Sea, Olsen says. The subsea multiphase compressor enables boosting of unprocessed wet gas production fluids, from 0-100% liquid phase, eliminating the need for an upstream separation facility or an anti-surge system, and making it the industry's only true wet gas compressor. It is expected to increase the recovery rate for the Gullfaks South Brent reservoir by 22 MMboe. OE

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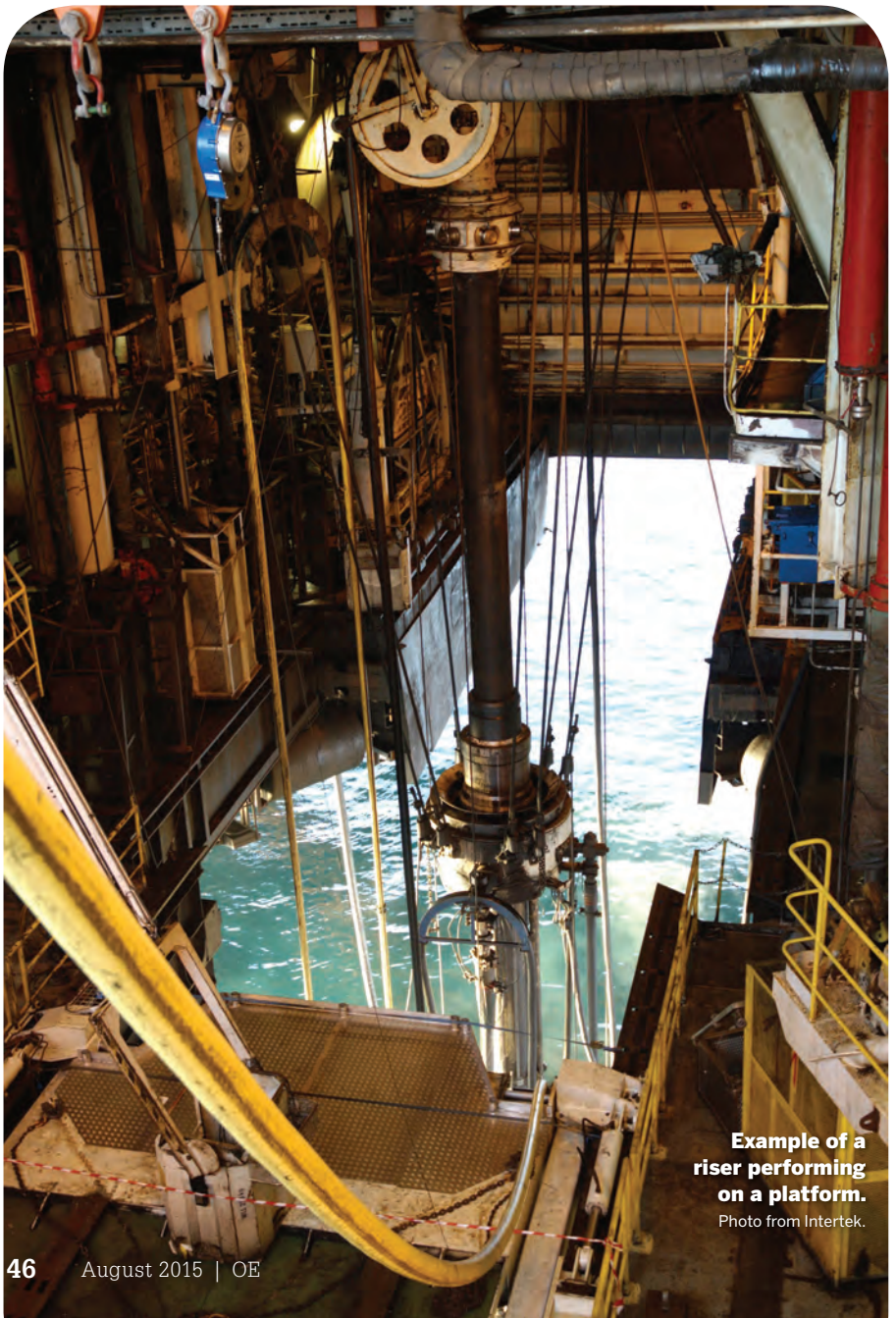
Corrosion fatigue behavior of high-strength steel wire

Applying materials and corrosion science to the study of corrosion fatigue in high-strength steel wire aids flexible riser performance understanding. Intertek's Peter Barnes explains.

In the oil and gas industry, flexible pipework has been used for over 30 years to transport oil-based products from the seabed to floating production, storage and offloading vessels.

Their flexibility means that this type of pipework can withstand a greater wave loading and that it requires shorter lengths than rigid-bodied alternatives, making it cost less. It also has the advantage of reduced installation times and being better at adapting to change in field layout.



Example of a riser performing on a platform. Photo from Intertek.

Flexible pipes are commonly used in dynamic and static risers, static flow lines, jumpers and expansion joints. Although suitable for all markets, their versatility and ability to adapt to the changing demands of the offshore oil and gas industry makes them ideally suited to deepwater, ultra-deepwater and the increasingly challenging environments of new field developments.

The structure of an unbonded flexible pipe, consists of a carcass, an inner liner, pressure armor, tensile armor and an outer sheath. The carcass prevents the inner liner from collapsing while performing under high external pressures in deep oceans. It also provides protection against maintenance operations, such as the pigging tools that are used to inspect the pipeline. The pressure and tensile armor layers are both made from carbon steel wire with either a flat or interlocking profile.

The region between the inner liner and the outer sheath is termed the annular space. The environment within the annular space can determine the life of a flexible riser as it can contain corrosive gases, condensed water and seawater. There are acknowledged to be two main modes of failure of the steel wire. The first is damage to the outer sheath, due to the aging of the thermoplastic sheath or damage during installation, caused either by foreign objects rubbing against it or becoming embedded in the pipe sheath. This leads to ingress of seawater into the annular space, enabling the corrosion fatigue process to begin. The second mode of failure occurs when permeation of corrosive gases and condensed water through the inner polymer sheath leads to a corrosive environment within the annular space.

Both corrosive environments, combined with the wave loading from the sea, lead to corrosion fatigue failure of

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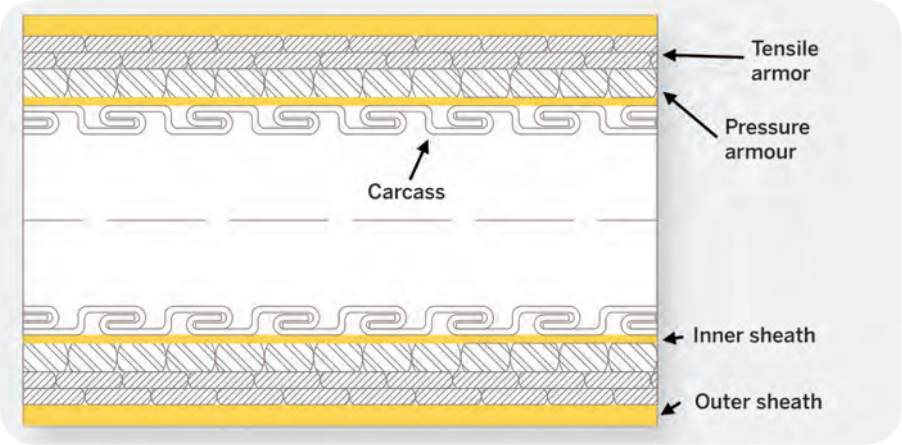

Flexible riser schematic. Source: Intertek.

the steel wire within the tensile armor.

We tested the corrosion fatigue of high-strength steel wire in four different solutions. The purpose of this was to compare the effects of chloride and iron ion concentration on the corrosion fatigue behavior of the high-strength steel wire, which allowed us to simulate the different failure modes. The four solutions tested were modified (5%NaCl) ASTM D1141 synthetic seawater, iron supersaturated modified (5%NaCl) ASTM D1141 synthetic seawater, deionized water and iron supersaturated deionized water

These tests explored the effects of the different environments on the corrosion fatigue behavior in terms of levels of iron (Fe2+) and sulfide (S2-) ions in solution and pH. The fracture surfaces that considered iron saturation and the seawater environment without iron saturation demonstrated signs of corrosion on the fracture surface and exhibited a ductile type failure. The fracture surface of the tensile armor tested in a deionized water environment without iron saturation exhibited a brittle type failure.

Iron saturation reduced the effects of hydrogen sulfide corrosion through the reaction of Fe2+ ions with the S2- ions, which produced an iron sulfide precipitate. This reduced the sulfide in the solution to zero after one and two days' exposure for the seawater and deionized water environments, respectively. The iron ion saturation ultimately leads to the lowering of the corrosion rate. There are approximately twice as many Fe2+ ions in the solution for the seawater environment than for the deionized water environment, which would correspond with a lower corrosion rate.

The pH of solution of the two iron-saturated environments showed a reasonably stable pH throughout the fatigue test period of 6.2. The pH for the seawater and deionized water environments without iron saturation were lower, with values on average of 5.4 and 5.1, respectively.

Using a materials and corrosion science approach to study the corrosion fatigue of high-strength steel wire in various environments aids understanding of flexible riser performance thresholds for industry suppliers and operators.

Putting this knowledge into action allows operators to engage in better planning for prevention of corrosion fatigue, with a more diligent approach saving them time and meeting health and safety regulations more effectively. This approach also saves costs, improves safety and reliability and enhances the life of the riser by ensuring that risks to its integrity are mitigated insofar as possible. OE

Dr. Peter Barnes is a senior engineer at Intertek Production and Integrity Assurance, part of the company's Exploration and Production business. He has 13 years' experience in the water, nuclear and oil and gas industries working with clients on asset integrity management, corrosion fatigue, design, construction and water treatment projects, among many others. Barnes has a PhD in corrosion fatigue from the University of Manchester.

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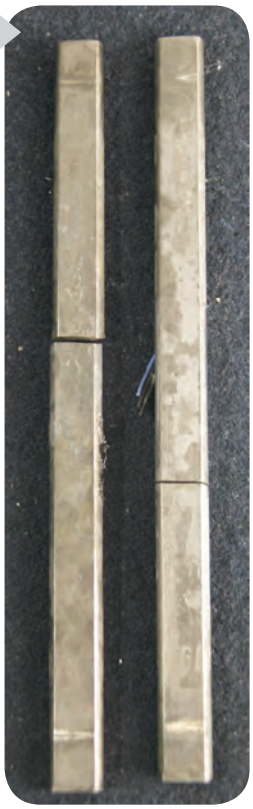
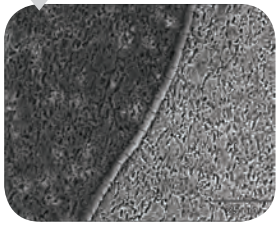
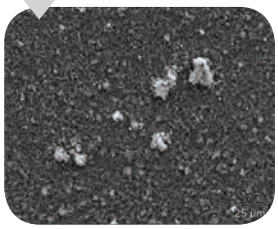
Post-fatigue sample from seawater. Photos from Intertek.



SEM surface scale image showing a barrier between the formation of iron sulfide and iron carbonate.



SEM surface scale image showing iron sulfide precipitates.



FPSO in service. Photo courtesy of Intertek.

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- ☐ 28 Consultant
- ☐ 29 Seismic Company
- ☐ 30 Pipeline/Installation Contractor
- ☐ 31 Ship/Fabrication Yard
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Southeast Asia in focus

Despite the downturn, plenty of development is underway in Southeast Asia. Audrey Raj sets out the detail.

Bach Ho oil field in Cuu Long basin. Photo from PetroVietnam.

Despite the fall in oil prices, Southeast Asia (SEA) will see investments in offshore projects, which are commercial at the current price of US$65/bbl.

The region, particularly rich in oil and gas in countries like Malaysia and Indonesia, will continue to be an increasingly important area for global offshore developments.

SEA has long been a center for construction and fabrication within the offshore market, while economic advancement and rising energy demand has spurred on technological development.

According to Infield Systems' published content analyst, Catarina Podevyn, during the next five years, SEA is likely to see growth in the liquefied natural gas (LNG) sector, with the emergence of the floating LNG (FLNG) technology.

"Key FLNG projects include Petronas' PFLNG-1 and PFLNG-2 units, while we also expect for expenditure to be required on Indonesia's Abadi FLNG facility from 2018 onwards," Podevyn says.

"Deepwater fields are forecast to comprise an increasing share of SEA's capex demand up to 2020, with expenditure demand in deepwater to form 25% of total spending during the 2016-2020 timeframe," she continues.

Driven by Malaysia, one key project is the Rotan field in the South China Sea, offshore Sabah. Petronas' PFLNG-2 is being designed for this field to produce some 1.5 MTPA ton of LNG.

Offshore Indonesia, Podevyn expects significant deepwater developments as well, with the capital intensive Gendalo field holding the largest share of expenditure.

Gendalo field is part of the Indonesia Deepwater Development (IDD) project consisting of five fields, including Maha, Gandang, Gehem and Bangka.

Situated in the Kutal basin, IDD is known to be the deepest offshore project undertaken in Indonesia, sitting in waters ranging 610-1829m deep.

GlobalData's Asia-Pacific senior upstream analyst Joseph Gatdula points out another emerging trend in the SEA offshore sector, which is the continuation of large scale projects already sanctioned and the commercialization of gas fields throughout the region.

"One such key bellwether will be the Lengo field also in Indonesia, which looks to capitalize on the local East Java gas market. But the final investment decision (FID) will heavily depend on the long-term contract prices currently under negotiation," Gatdula says.

Located 197ft in the Bulu production sharing contract (PSC), the Lengo field operated by KrisEnergy is estimated to produce some 70 MMcf/d of gas.

Furthermore, a report by consulting firm Frost and Sullivan revealed that Malaysia and Indonesia are set to become the most lucrative markets in SEA's offshore oil and gas services sector.

With both countries witnessing the highest exploration activities, they will become the largest markets for offshore support and pipeline services.

The report found that while global drilling, marine and pipeline support

PFLNG-1. Photo from Petronas.

Petronas engineers. Photo from Petronas.

service markets collectively earned revenues of $200 billion in 2014, this is set to reach $241 billion in 2018.

"Despite the oil price situation, the SEA offshore oil and gas services market managed to generate revenues of $25 billion in 2014," notes the firm's energy and environmental consultant, Daniel Wicaksana.

"A lot of different players ranging from large multinational companies to medium- to small-sized regional and local companies have been driving total market revenues," Wicaksana explains.

Issues and challenges

While aging offshore infrastructures and declining production are particular challenges in SEA, the Indonesian offshore sector lacks investment, Podevyn says.

Coupled with rising domestic energy demand, this has resulted in the country now facing the possibility of becoming a net gas importer by the end of the decade, despite being one of the leading global exporters of LNG.

"While deepwater prospects within the region have been on the increase, we have seen a number of delays over the last eight months, although Infield Systems does not expect the current low oil price to prevail over the long-term," Podevyn says.

"Deepwater development also brings with it operational and technical challenges, and in a region not traditionally associated with deepwater work, national oil companies (NOC) will have to work with experienced operators and contractors from outside the region," she adds.

GlobalData expects operators to push equipment and service providers even harder in cost reductions in the offshore sector, as reflected by the significant drop in day rates for rigs in the region.

"We also anticipate operators

maximizing the use of existing infrastructure to lower development costs, including the use of subsea tiebacks to develop new fields," Gatdula says.

Growth and investment

Indonesia has potential to grow, with the caveat that it is dependent on a raft of potential changes instituted under new government initiatives, including the effort to reduce corruption.

Since, the Widodo government has reduced fuel subsidies and allowed free market approach to pricing of both gas and crude, Gatudala says this should raise prices and allow for better field economics.

"A planned license round for 2016 is also rumored to have the potential for significant changes in the fiscal terms needed to spur exploration and development within the 10-year window," he says.

Indonesia is also expected to see the largest investment growth throughout the five-year timeframe with Infield Systems expecting a CAGR of 25% from 2016-2020.

"Investment demand is expected to be driven by the IDD development, although full operation of the project has been delayed as Chevron revises its development plans," Podevyn explains.

"Other key projects to take place offshore Indonesia during the following five years, include East Natuna and the Eni-operated Jangkrik development."

The East Natuna field in the Greater Sarawak basin north of Jakarta is developed by the Indonesian state-owned oil company, Pertamina and contains approximately 46 Tcf of gas.

Consisting of Jangkrik and Jangkrik Northeast fields, production start-up at the Jangkrik development project in the Makassar Strait is likely to begin in 2017.

Myanmar, too, is scheduled to have a round of licensing in 2016. According to the Ministry of Energy, the country has 104 oil and gas blocks, and only 19 out of the 51 offshore blocks are in operation.

In its move to attract more investors, last year Myanmar made changes to its oil and gas investment regulatory framework. Now, investors keen on deepwater blocks will not require local partnering, but shallow water explorers are called to find local partners.

According to the Myanmar Investment Commission, Myanmar has received more than $8 billion in Foreign Direct Investment (FDI) last fiscal year and the oil and gas sector drew $3.6 billion.

In 2014, 40 offshore and onshore blocks were awarded to industry players such as Chevron, Shell, Total, BG, Petro Brunei and PTT Exploration and Production (PTTEP).

Activities are expected to pick up towards the end of 2015 or early 2016, as some of the winners kick-start their seismic surveys.

Malaysia, Podevyn says, is expected to remain the largest market for offshore demand going forward to 2020 with a 37% market share of SEA capex demand during 2016-2020.

"However, going forward to 2020 Infield Systems actually expects a decrease in expenditure by a CARG of -5%. Key projects driving demand will include the Rotan FLNG development and the Petronas-operated Bokor field," she says.

"Thailand will see a small increase in offshore capital expenditure over the 2016-2020 timeframe compared to the previous five years, with expenditure demand expected to peak in 2018.

"Ubon field is expected to be a key development for Thailand going forward, while the pipeline sector is likely

to require the largest expenditure demand over the five-year period," Podevyn adds.

Thailand is also attempting to reform its energy sector, with a delayed bid round due to occur in 2015. The delay was because of adjustments in the fiscal policy to improve conditions based on the current market.

"As part of this effort, Thailand has committed to definitively outline the concession renewal mechanism to assure operators of the long-term stability of currently producing supply," Gatudala says.

Most of Vietnam's oil production comes from the Cuu Long basin comprising of large oil producing fields with an estimated 3.37 billion bbl of potential crude oil.

PetroVietnam workers at Dai Hung oil field. Photo from PetroVietnam.

Although it is one of the most difficult environments to explore, wells that once took about three months to drill can now be completed within six weeks because of advanced technologies.

Despite the drilling and geological challenges, PetroVietnam is looking to further explore the potentials of the area and is actively seeking investors.

Vietnam's Block B – operated by PetroVietnam in the Malay-Tho Chu basin holding about 5 Tcf of gas and condensate – Gatudala says is slated to cost upwards of $10 billion.

"As the development plans come together, we anticipate a commercial decision later in 2016," Gatudala concludes. **OE**

Boundary disputes: South China Sea

Offshore assets in the South China Sea are ripe for further development, but territorial challenges are common. Focusing on Vietnam, Jeannie Stell talks to Quynh Anh, partner at Mayer Brown, for an overview of the political conditions, contract details and royalty rates that can affect energy development.

The South China Sea (SCS) offers potential for significant natural gas discoveries, creating incentive for countries to secure large sections of the area for domestic production. Yet, the region has historically been a source of conflict among its shoreline countries. In some cases, oil and gas exploration and production companies have initially been permitted to explore for oil and natural gas by one country, only to later be denied access by another country.

For example, Vietnam claims ownership of the Paracel and Spratly islands, although the extent of its territorial and maritime claims in the SCS are not delineated in text or on maps.

However, in 1974, China seized all of the Paracels. But, Hanoi claims that, because France controlled both island groups starting in the 1930s, Vietnam succeeded to those rights after independence. Brunei, China, Taiwan, Malaysia, and the Philippines disagree with that claim.

Last year, in what has become known as the "Haiyang Shiyou 981 Standoff," tensions between China and Vietnam rose to the surface when CNOOC moved its *Haiyang Shiyou 981* semisubmersible oil platform to waters near the disputed Paracel Islands, which resulted in Vietnamese efforts to prevent the platform from establishing a fixed position. Initially, the *Shiyou 981* operators intended to conduct well drilling from May to August 2014. However, on 15 July, China announced that the platform had completed its work and withdrew it fully one month early, thus relieving tensions in the area.

These types of territorial disputes continue as Asia's economic growth drives liquid-fuels consumption. Total demand by Asian countries outside the Organization for Economic Cooperation and Development (OECD) is expected to rise by 2.6% annually, growing from 20% of world consumption in 2008 to more than 30% by 2035, according to the US Energy Information Administration. Similarly, non-OECD Asia's natural gas consumption will grow by 3.9% annually, from 10% of world gas consumption in 2008 to 19% by 2035. As a result, Southeast Asian countries are motivated to find and produce more offshore oil and gas.

Furthermore, because Southeast Asian countries such as Vietnam, Malaysia and Brunei lack significant onshore hydrocarbon potential, these countries are significantly driven to invest in offshore production, technology, pipeline networks and drilling. Overall, the majority of the countries' oil and gas developments are found in shallow water basins because the region has seen limited exploration of deepwater areas, mostly due to a lack of capabilities.

Yet, more recently, finds such as China's Liwan 3-1 gas field, discovered in 2006, demonstrate the potential of deepwater exploration. As a result, some countries have opted to cooperate in the SCS, such as the partnership between Malaysia and Brunei to explore offshore Brunei waters, and the agreement of Thailand and Vietnam to jointly developed areas of the Gulf of Thailand, despite ongoing territorial disputes.

These success cases contrast with areas of the SCS contested by multiple countries, where such areas have undergone scarce energy development. Differences in political conditions, royalty rates and territorial water disputes continue to interfere with hydrocarbon developments.

Vietnam issues

While SCS territorial offshore disputes continue, and despite the *Haiyang Shiyou 981* Standoff, Vietnam can be seen as an example of movement toward international cooperation. However, this was not always the case.

"The escalation of territorial disputes in the South China Sea — which the Vietnamese call the East Sea — have been causing great concerns for the Vietnamese government and international oil and gas companies that have been exploring oil and gas opportunities in Vietnam," says Quynh-Anh Lam, a

Ho Chi Minh City-based counselor for the law and consultancy firm of Mayer Brown. She is a member of the firm's Global Projects Group.

"While there seems to be no expressed indications that the territorial water disputes alone have adversely affected the oil and gas activities, we understand that certain international oil companies (IOCs) have expressed their hesitance when being invited to bidding rounds for new production-sharing contracts," she says.

Increasingly, IOCs seem to be under pressure to take sides when expanding in the region, and those with strong political alliance to a particular country would feel inclined to expand in such country. That said, it seems that the territorial disputes are not yet cited as the sole reason for IOCs to exit a particular country.

"In terms of internal political stability, Vietnam is often cited as a stable political regime with leadership committed to achieving socio-economic development. The communist party in Vietnam seems committed to achieving high gross domestic product growth and aims to achieve this by providing a relatively stable political environment, especially when compared to its neighbor countries. In fact, since it first opened doors to foreign investors in the late 1980s, the situation in Vietnam has been rather stable and it has not faced the political upheavals or difficulties experienced in its neighboring countries such as Thailand, the Philippines or Myanmar." As a result, Vietnam tends to be an attractive area for energy development and investment.

Activity in Vietnam

For example, in March, PetroVietnam formed a joint venture with Italy's Eni and signed two production-sharing contracts for exploration of blocks MD-02 and MD-04 offshore Myanmar. Eni operates the joint venture with 80% interest, PetroVietnam holds the remaining stake.

The MD-2 Block is in the southern part of the Bay of Bengal in the Rakhine basin, about 135km west of the Yadana field, the major offshore discovery in Myanmar. The block covers 10,330sq km in waters 500-2400m deep. MD-4 Block is in the Moattama-South Andaman basin, about 230km off the coast, west of the Yetagun gas field. The block covers 5900sq km in waters 1500-2200m deep.

Among other various other joint ventures, PetroVietnam is working with ExxonMobil, which has two operating licenses under production-sharing contracts for the Da Nang and Vung May blocks offshore central and southern Vietnam.

Royalty rates

The current contract royalty rates in Vietnam that are applicable to oil production range from 7% to 29%, says Lam, which are applicable to production of 20,000 b/d or higher, whereas the royalty rates applicable to gas production range from 1% to 10%, applicable to production of 5 MMcm/d or more.

Although the royalty rates applied in Vietnam appear to be higher than other oil- and gas-producing countries in the SCS region, the contracts are contingent upon the production volume of a particular oil or gas field. For example, the operators of an oilfield producing less than 20,000 b/d or operators of a gas field producing less than 5 MMcm/d could enjoy royalty-free production in Vietnam.

With this royalty structure, and continued cooperation between Vietnam leaders and various NOC and IOC energy companies, today's offshore territorial disputes could become less prohibitive in the future. OE

Understanding the changing workforce

Social collaboration brings context to data and helps find experts. Tom Franklin reports.

Global integration in the oil and gas industry is bringing about changes in the nature of its workforce and operations.

With potentially 50% of the workforce likely to retire in the next 5-7 years, there are concerns about losing valuable expertise. Add on top of that the changing nature of work as companies explore more remote and harsh environments to enhance production. This requires advanced technological skills often held by just a few experienced employees. Also, with businesses becoming global, oil and gas companies need to contend with changing government regulations that demand local resources to ensure smooth operations in remote environments.

In a knowledge-intensive industry, all these changes pose big challenges for employee retention, engagement, training and productivity.

There is, however, an answer. By taking a more holistic view of multiple dimensions involving people, processes and technology, it is possible to create a more collaborative and productive work environment.

The consumerization of IT and trends like BYOD (bring your own device), combined with the widespread prevalence of social networking platforms and mobile devices, present opportunities for creating a more connected workplace. Considering that oil and gas projects typically include geographically dispersed stakeholders, a social collaboration platform can help discover, capture and share tacit knowledge more effectively from a dwindling workforce.

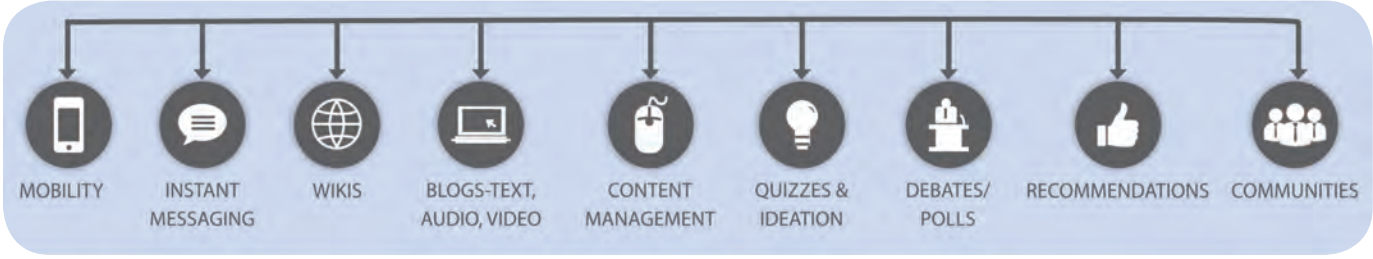
As mentioned, studies show 40-60% of current employees (mainly geoscientists and petroleum engineers) are planning to retire in the next 5-10 years. They also show there is a considerable gap in experience between the retiring and the incoming workforce. About 20% of the industry has fewer than five years of experience, and the average age of exploration and production company employees is 50 years. What does this mean for oil and gas companies? The Talent and Technology study from SPE estimates such loss of expertise could result in losses amounting to US$40 billion. Moreover, 20-30% of drilling efficiency could be lost once experienced drillers hand over operations to their replacements.

To further complicate matters, the industry is undergoing changes with regard to locations explored, methods applied and products churned out (conventional oil versus unconventional oil). New and complex techniques, as well as experiential knowledge and best practices, must be understood by new hires and other stakeholders across geographies.

In addition, the need to find new oil reserves has driven companies to explore and operate in harsh, remote and even hostile locations. This shifts the focus to unconventional exploration techniques that require the support of digital technologies and extensive technical expertise. However, finding the talent with experience in new technologies and unconventional production techniques is not a simple task.

Taking a quick look, it is easy to see the current education system does not support the growing need for skilled resources. People graduating as geologists every year, from universities across the globe, form only a miniscule percentage of graduates compared to other disciplines like law, medicine and engineering. Therefore, oil and gas companies should either train new hires or recruit personnel from other countries to bridge this gap. Industry players remain challenged to train these employees quickly to maintain productivity. Effective knowledge management and collaboration is not only critical to bridge these gaps and prevent loss of critical expertise, but it is also necessary to build new competencies.

A more connected workplace that enables an easy exchange of information is a business imperative.



The key capabilities of an ideal social collaboration platform. Images from Tata Consultancy Services.

Social collaboration

While, it would be easy to say this is just a human resources issue, it is important to address the issue from a business perspective. The solution starts with understanding the needs of "digital natives" entering the organization who are comfortable with social networking tools, and providing an environment that

enables experienced employees to share their expertise through this emerging medium.

Driving collaboration through social media and other tools generates significant business value by improving the way knowledge is created, accessed, shared and used. From routine tasks to special projects, social collaboration transcends geographical boundaries. It captures the tacit knowledge of experienced employees by motivating them to contribute through intuitive and easy-to-use platforms. At the same time, it offers a new -generation employees access to collaborative technologies, which allow them to leverage the knowledge ecosystem for faster integration within the enterprise. Such technologies also help to create a network of support through communities of practice and to connect companies with academic institutions to prepare students even before they enter the industry. A key step in adopting social collaboration is to focus on choosing an enabling technology, or building a service line to create the right platform.

The pathway to social collaboration for improved productivity.

In with the new

Timely access to the right data, information and expertise is one of the strongest drivers for social collaboration in the oil and gas industry. The amount of data — which is mostly unstructured in nature — is growing due to the rising complexity of technology. Therefore, a good part of an engineer's time is spent gathering data and information rather than analyzing it. Downtime ends up largely attributed to the difficulty in finding correct information in a timely manner.

Although typical content management initiatives provide the means to manage data, they do not enable contextualization. They fall short of a comprehensive knowledge management platform. Traditional enterprise content management (ECM) systems are driven by enterprise taxonomy and capture knowledge that is possible to document. These systems are not well equipped to tap into unstructured sources such as emails, instant messaging and other sources of tacit information. Moreover, ECM works within the boundaries of workflows and file management systems, and struggles to gather digital content (like videos and images) created through a series of disparate, unorganized processes.

Existing ECM systems are also mere repositories of processes. More often than not, users built these content management solutions piecemeal for a particular business unit, and focused on providing employees with the knowledge they require for conducting routine tasks. They do not provide an interactive environment where employees can post their queries and get the required support to develop solutions for more specialized projects. Certain components of ECM allow for collaboration and communication. However, since the focus is implicitly on content creation and storage, important documents might not remain "alive" for extended periods of time due to a lack of collaboration.

Social collaboration takes knowledge management beyond the rigid structures of taxonomy and toward "folksonomy," where the user can categorize content through collaborative tags and annotations. Social collaboration platforms have evolved from the traditional system of records to becoming systems of engagement. While ECM does extend some collaborative features such as simultaneous editing of documents and integration with instant messaging, it is mainly a system of records. Social collaboration platforms aim to overcome the challenges posed by ECM systems by bringing:

- Context to data
- Help in the discovery of experts
- Capture unstructured knowledge across the enterprise

Social collaboration components

As a networking tool that enables collaboration within the enterprise, a social collaboration platform should also encompass the social strategy for an enterprise, along with the associated policies and processes.

An ideal social collaboration platform should be easily accessible through mobile devices such as smartphones and tablets, and be available around-the-clock for access anywhere. It should allow users to share information and communicate with each other through instant messaging, blog posts and wikis. Though

the information generated through social collaboration platforms is vast, the use of features such as hash tags contextualizes the information. Activity feeds, based on user-specific subscriptions, enable the generation of personalized streams of information to maintain subject relevance.

It can become possible to generate ideas through crowdsourcing, either for specific topics or in response to general industry trends. The platform should also offer discussion boards and polls that help in driving conversations around industry relevant topics. Instant access to the appropriate subject matter experts, through communities and other private and public forums, will enable faster problem resolution. By integrating with a comprehensive content management system, the platform should also enable real-time storage and retrieval of content.

Collaboration success factors

Consider an example with an oil well that goes offline frequently, and with production engineers and operators who are unable to identify the problem. Add in the employees who may have worked on various well components such as lift technology, pumps, and others, may have also moved on.

These types of issues could end up posted to communities on a social collaboration platform to reach the extended workforce – contractors, suppliers, and ex-employees. The social collaboration platform can also provide specific workflows that allow ex-employees to participate in discussions until the problem is resolved.

Building a social collaboration platform is just the beginning. The following key factors will ensure faster adoption and continued success:

- **Change management:** This will influence how well employees are able to adapt to the new collaborative work environment.
- **Collaborative culture:** Technology is just one element of social collaboration; participation hinges on building and sustaining people's interest. Enterprises should make an all-out effort to motivate employees through senior leadership participation and recognition programs.
- **Ease of use:** The collaboration platform should require minimal training and be easy to use. Ensuring uninterrupted availability of the platform on mobile devices will also help boost participation.
- **Ability to evolve with changing needs:** The social collaboration needs of an enterprise and its employees can change over time. The right support will be able to handle multiple iterations to meet these changing goals and employee expectations.

Immense potential

Social collaboration tools are changing the way we communicate and exchange information outside and within the workplace. Businesses are already using it to support their marketing efforts and engage their customers.

For the oil and gas industry, social collaboration holds immense potential in capturing and disseminating knowledge sourced from experienced employees. Enterprises will need to think beyond traditional databases or content repositories, and embrace new social tools that drive continuous improvement of knowledge and skills. Building communities of interests and using discussion groups and podcasts could be some ways to connect with the right experts across the organization and accelerate issue resolution and decision making.

While these are important steps in the process, the greatest success lies in a shared vision of social collaboration, as well as rethinking organizational ethos and the ways of working.

The demand for specialized skills and the influx of digitally savvy employees will require tools and technologies that support idea generation and open avenues for continuous innovation. In addition, such collaboration should happen anytime and anywhere to meet the needs of a geographically dispersed workforce. Future success will lie in adopting social media and mobility-enabled collaboration that will pave the way for a more agile, responsive and productive enterprise. OE

***Tom Franklin** is a domain consultant and an industry advisor with the upstream segment of the Energy and Resources business unit at Tata Consultancy Services (TCS). He has over 30 years' experience in the industry. He was a contributor to the Cambridge Energy Research Associates landmark study, "The Quiet Revolution" that assessed the impact of information technology on the petroleum industry.*

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Activity

Tough times – but no complacency

In today's climate, helping the next generation understand the importance and longevity of the oil and gas industry is more important than ever, says SPE Offshore Europe co-chairman Charles Woodburn. Elaine Maslin explains.

When the organizers of this years' SPE Offshore Europe picked the theme, "inspiring the next generation," oil prices remained high and the need to attract talent was at the top of the agenda.

It could be surprising, then, that after the precipitous oil price fall from US$100/bbl down to $50/bbl and with the market expected to remain tough into 2017, the organizers still believe it is the right theme for this year's event.

Charles Woodburn, SPE Offshore Europe co-chairman, and Expro Group CEO, is unapologetic in his belief that as much needs to be done now, if not more, to attract people into this cyclical industry, so that when activity once again returns, it will have the talent it needs. "Our view is that 'inspiring the next generation' is as relevant as ever," he says. "It draws into stark contrast the challenges we face around encouraging youngsters in to our industry."

"We know the market will recover as supply and demand rebalance, and that is a matter of timing. What is key, in any cyclical industry is flexibility, but there are hard choices to be made since downsizing in the short term means a reduced capacity to respond when the up cycle returns. It is a delicate balancing act. When you recruit people, it normally takes at least 12-18 months before they are working autonomously. But we need to ensure we will be ready with a pipeline of talented people, bearing in mind these time frames. In terms of up cycle visibility, we are not there yet, but we are watching very carefully.

UKCS needs new thinking

With just weeks to go before SPE Offshore Europe brings the oil industry to Aberdeen, Neil Golding takes a look at activity on the UK Continental Shelf – and what needs to change.

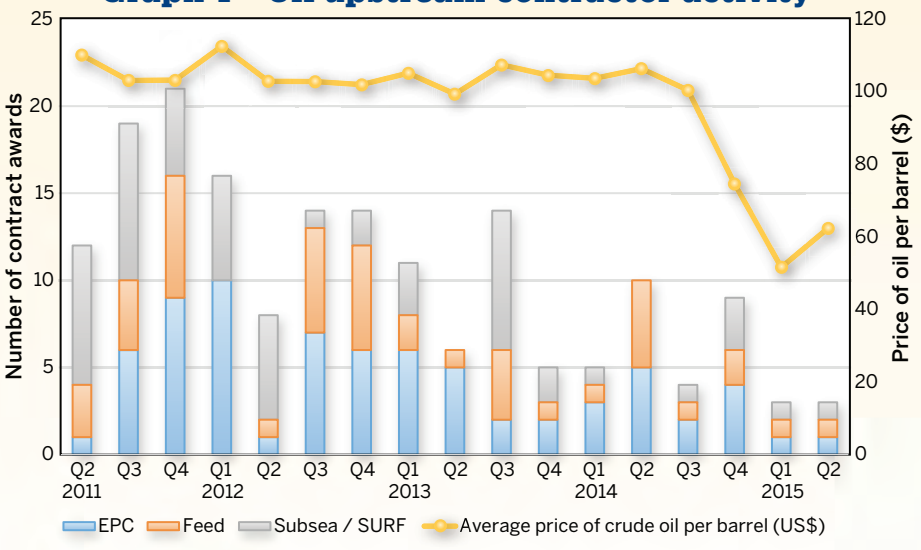
By Neil Golding, Head of Oil & Gas, The Energy Industries Council

The oil price is being blamed largely for the slowdown in activity and new opportunities in the North Sea market for the supply chain.

Analysis of contracting activity in the market, however, shows that since 1Q 2012, we have seen a decline in the award of major contracts on project developments on the UK Continental Shelf (UKCS), well before the drop in oil price. Graph 1, extracted from the EIC's project tracking database EICDataStream, highlights this with drops in EPC, FEED and subsea/SURF contract awards.

The issues being talked about now

Graph 1 – UK upstream contractor activity



"My personal view is that this year is going to remain tough and [given the time bidding activity takes to translate into real activity] it is going to remain so for the remainder of this year and well into next year. At the back end of this year and in to next year, there could be some rebalancing of supply and demand, which should give some form of confidence around a recovery going into 2017. But, crystal ball gazing is never easy and there is wide debate about what the new normal will be."

The challenge around being the right size at the right time will be one of many to be discussed at Offshore Europe. Others include how to find efficiencies and standardization, and where lessons can be learned from other industries or even different segments of the global exploration and production business.

Charles Woodburn, Expro Group CEO.
Photo from Expro Group

"The industry has a huge capacity to reinvent and innovate, especially in challenging environments. But, at the same time, there are plenty of areas for improvement," Woodburn says. "A case in point is the rapid development of unconventional and tight oil and gas. A lot of lessons were learned there that can be applied in the offshore industry, such as standardization and efficiency. Having seen the oil price come down, a lot of deepwater developments with marginal economics would benefit from similar improvements in standardization and efficiency."

Technology which can extend, enhance and increase recovery rates, cost effectively, is also high on the agenda, such as more cost effective subsea interventions and more economical well construction, Woodburn says.

For Woodburn, while it could be easy to say, that 'despite the challenging back drop, SPE Offshore Europe is an excellent opportunity,' it is because of the challenging back drop, it is a great opportunity, "to get the industry together to have a constructive debate and discussion about all the issues we are facing, like the timing of a healthy recovery and how to recruit and attract the talent we know we are going to need again."

"Most commentators say that mid this century, three quarters of our energy will come from hydrocarbons – oil, gas and coal – still. We have a tremendous responsibility for energy security and supply, which in turn impacts global economics. It is a huge challenge for us all and we need everyone to be aware of the key elements of that. Getting youngsters to appreciate that and the longevity of this industry is key." OE

have been discussed for some time by the industry. Reductions of costs, fiscal stability, government support, collaboration, and standardization have all been topics and concerns aired publicly by operators, contractors and the various trade associations involved in the sector.

The UKCS is well known for being an expensive place to do business. Operators in the region had been wrestling with the issues of costs well before the drop in the price of oil and this saw a number of projects suffer delays in moving forward. These increasing costs, which inevitably led to smaller margins, saw the operator landscape change in the early part of the decade where some of the major players divested assets to smaller companies (ExxonMobil and Apache, for example).

These smaller players looked at ways of increasing and enhancing production of these assets and with some success. We are again beginning to see the emergence of new smaller players, with significant financial backing from various houses, who have started to look at cutting costs and improving efficiency while maintaining, and in some cases, increasing production.

Throughout the supply chain and amongst operators, there is a requirement for new thinking in the current climate and the opportunity to begin to look in more detail at the standardization of developments. The industry from the majors down to the small operators have a role to play in establishing standards that are used throughout the sector. The establishment of uniform standards would cut costs and save time for the supply chain, especially if the operators standardised tender documentation.

The establishment of the Oil & Gas Authority (OGA) in the UK is a positive move and it would be expected that its establishment will improve working practices in the industry and increase efficiencies. Opportunities will emerge in the sector for enhanced recovery while it is hoped that, with the government fronting up £20 million (US$31 million) for a new seismic survey to be shot in the North Sea, exploration drilling rates will increase in the mid-term. The drop in the oil price has seen a drop in rig costs and it could be an opportune moment for operators to start up new drilling campaigns.

While times are undoubtedly difficult for all involved in the upstream oil and gas sector, in the current climate opportunities still exist for the supply chain. Encouraging news is coming from the Culzean development (Maersk Oil) with the final investment decision expected by year end, while work on Mariner (Statoil) continues at pace. The decommissioning market is also set to grow in the coming years and will provide the UK supply chain with the opportunity to establish itself as a world leader by using the UKCS as a learning ground before exporting this knowledge globally. OE

Solutions

North Sea drilled with 45in bit

The North Sea operation of Hess Corp. completed a contract that is believed to be the first to use what is believed to be the world's largest oilfield drill bit.

Varel Oil & Gas Dill Bits was commissioned by Hess to design and build the 45in L111 (1.143m) diameter drill bit. The 5100lbs heavyweight was manufactured in Mexico before being shipped to Aberdeen for use in the Danish sector of the North Sea.

The milled-tooth roller cone bit was built to drill top hole sections big enough to run two subsequent 16in sections in a splitter well configuration by installing 40in conductor through 46in guides.

The hybrid bit, which incorporates an interchangeable polycrystalline diamond compact bit in the center, avoids the need for the pilot hole/rat hole traditionally associated with a hole opener assembly, as well as offering easier handling and reduced risk of failure. It is being used over a series of splitter top holes in two drilling platforms located in the North Sea. www.varelintl.com

Frog-6 makes debut off Mexico

Reflex Marine's first personnel transfer device is now operational in Mexico after being certified by the Mexican Merchant Marines. Reflex Marine's six person transfer device, the FROG-6, was purchased by Olympic Shipping for use on their accommodation vessel, the MPSV *Olympic Triton*. The FROG-6 is being used to transfer *Olympic Triton*'s crew to and from other crew boats and supply vessels working on the Cantarell oil field in the Gulf of Mexico.

The FROG-6 provides protection from: Falling, collision, heavy landings and immersion. Also, the buoyancy panels provide self-righting and floatation in the event of immersion in water. These panels are coupled with a stainless steel frame, shielding passengers from side impacts, while the polymer foam landing feet help reduce vertical impacts.

The FROG-6 seats are mounted on coil springs combined with gas dampers to protect passengers from heavy landings.

The FROG-6 also has a medevac capability that allows the device to safely move casualties. www.reflexmarine.com

WEG adds hazardous area motor

WEG, automation and drive technology provider, added the W22X 800 hazardous area motor to its product offerings.

The W22X 800 has a larger IEC 800 frame size and is designed to meet the needs of demanding energy-intensive medium-voltage and high-voltage applications delivering performance with efficiency up to 97.4%.

WEG's W22Xd hazardous area motors are designed to meet IE4 energy efficiency standards and cope with the rigors of aggressive and explosive atmospheres such as gas pipelines in the Arctic to drilling rigs in the hottest parts of the Arabian Desert.

The motors are available in sizes 3.0 kW to 1000 kW for gas groups IIA, IIB and IIC, and are ATEX Certified. www.weg.net

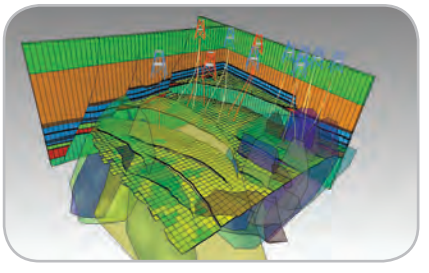
Baker Hughes releases JewelSuite 6

Baker Hughes has released its JewelSuite 6 software, which helps operators with data-driven decisions across all exploration and production domains with integrated applications for geological modeling and reservoir engineering, geomechanical modeling, and reservoir stimulation.

The geological modeling and reservoir engineering application can build models and run multiple scenarios in complex reservoirs that assist the user in determining an economically viable development plan for projects. The geomechanical modeling application assists users in predicting drilling and production problems and developing solutions to mitigate them.

The application can be used independently or as part of integrated geomechanical workflows— from 1D well-centric models to advanced 3D reservoir-centric models, 3D fault stability analysis and 4D full-field finite-element geomechanical simulations—all within a single interface.

The reservoir stimulation application enables operators to select the hydraulic fracturing design for unconventional field development that best meets their requirements. www.bakerhughes.com



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Spotlight

By Eugene Gerden

The show must go on

Eugene Gerden discusses Lukoil's current and future strategy with president Vagit Alekperov.

Lukoil, Russia's second largest oil company, aims to become one of the biggest players in the global oil industry and hopes to significantly accelerate its expansion in the offshore segment during the next several years.The privately-owned oil company was affected by Western sanctions imposed last year, having to re-evaluate plans to drill in Siberia with French explorer Total. However, despite this, the company plans to continue expanding its presence overseas.

It already holds interests offshore West Africa in Cote d'Ivoire, Ghana, and Cameroon; Lukoil is also a shareholder in the Shah Deniz field off Azerbaijan. The company has eyes on the domestic market, too, and in particular the Arctic shelf.

According to current Russian legislation, the development of the Russian Arctic shelf remains an exclusive prerogative of state-owned energy companies Gazprom and Rosneft, however, there is a possibility that such an opportunity may soon be provided to private companies, and in particular Lukoil, which has repeatedly expressed its readiness to start the development of the national shelf.

Vagit Alekperov, president of Lukoil, is a self-made billionaire, ranked No. 96 on Forbes 2015 ranking of the world's billionaires. Born in Baku, Azerbaijan, Alekperov attended the Azerbaijan Institute of Oil and Chemistry, earning a Bachelor of Science. He later worked as an engineer to work in the Caspian Sea. In 1987, he served as general director Kogalymneftgaz, and in 1993 became president of Lukoil.

Alekperov speaks with ***OE*** about Lukoil's future prospects at home and abroad, in the face of Western Sanctions.

Which offshore projects are a priority for Lukoil in coming years?

Despite the current low oil prices Lukoil plans to continue implementation of its investment program on the Caspian Sea shelf. As part of these plans, the company plans to begin drilling at the Filanovsky field, in the northern part of the Caspian Sea (and where recoverable reserves are estimated at 153.1 million tonnes) at the end of June 2015.

Lukoil's Vagit Alekperov. Photo from Gazprom.

In addition, Lukoil is also interested in the development of Russian Arctic shelf and has already started negotiations with Gazprom about the development of two blocks on the Arctic shelf, which will take place in the case of a receive permission on the development of shelf from the Russian government. It is planned that final state decision, regarding with this issue, is expected to be taken at the end of September.

How about foreign offshore projects?

Among the promising foreign projects is the development of the Western Africa shelf, and in particular Cape Three Points Deep Water oil and gas block in Ghana, where the company has recently discovered rich oil and gas reserves. In addition, we believe in Mexico. To date Lukoil has opened an office in Mexico City and has started talks with the Mexican state corporation Pemex about possible cooperation. Finally, Lukoil is interested in the shelf of Lebanon, as well as Brazil.

What was the effect of Western sanctions on the Russian oil industry and its leading companies?

This is a difficult question. In the case of Lukoil, sanctions have not resulted in the suspension of our current offshore projects, and in particular those, which involve the development of the Caspian Sea shelf, as the development of these fields is not associated with the need of the use of deepwater equipment, imports of which to Russia were banned, as a result of sanctions.

We do not have many projects where we heavily depend on imported technologies. However, despite this, we are still forced to operate in shallow depth and do not have an opportunity to get into other, more technically complex projects. At the same time, in addition to offshore projects, we plan to focus on upstream projects during the next 10 years. By 2019, we plan to complete all the projects related to the reconstruction of our refineries and the establishment of a retail network, which will allow us to take the entire product and sell it to the end customer. This will happen both in Russia and abroad. In the case of foreign markets, a particular attention will be paid to the US market, which will be a driver for the company's development in the upstream segment of the market. OE

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1. What is your main job function?
(check one box only)

- ☐ 01 Executive & Senior Mgmt (CEO,CFO, COO,Chairman, President, Owner, VP, Director, Managing Dir., etc)
- ☐ 02 Engineering or Engineering Mgmt.
- ☐ 03 Operations Management
- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations (All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)
- ☐ 99 Other *(please specify)*_____

2. Which of the following best describes your company's primary business activity?
(check one box only)

- ☐ 21 Integrated Oil/Gas Company
- ☐ 22 Independent Oil & Gas Company
- ☐ 23 National/State Oil Company
- ☐ 24 Drilling, Drilling Contractor
- ☐ 25 EPC (Engineering, Procurement., Construction), Main Contractor
- ☐ 26 Subcontractor
- ☐ 27 Engineering Company
- ☐ 28 Consultant
- ☐ 29 Seismic Company
- ☐ 30 Pipeline/Installation Contractor
- ☐ 31 Ship/Fabrication Yard
- ☐ 32 Marine Support Services
- ☐ 33 Service, Supply, Equipment Manufacturing
- ☐ 34 Finance, Insurance
- ☐ 35 Government,Research, Education, Industry Association
- ☐ 99 Other (*please specify*)_____

3. Do you recommend or approve the purchase of equipment or services?
(check all that apply)

- ☐ 700 Specify
- ☐ 701 Recommend
- ☐ 702 Approve
- ☐ 703 Purchase

4. Which of the following best describes your personal area of activity?
(check all that apply)

- ☐ 101 Exploration survey
- ☐ 102 Drilling
- ☐ 103 Sub-sea production, construction (including pipelines)
- ☐ 104 Topsides, jacket design, fabrication, hook-up and commissioning
- ☐ 105 Inspection, repair, maintenance
- ☐ 106 Production, process control instrumentation, power generation, etc.
- ☐ 107 Support services, supply boats, transport, support ships, etc
- ☐ 108 Equipment supply
- ☐ 109 Safety prevention and protection
- ☐ 110 Production
- ☐ 111 Reservoir
- ☐ 99 Other (*please specify*) _____

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