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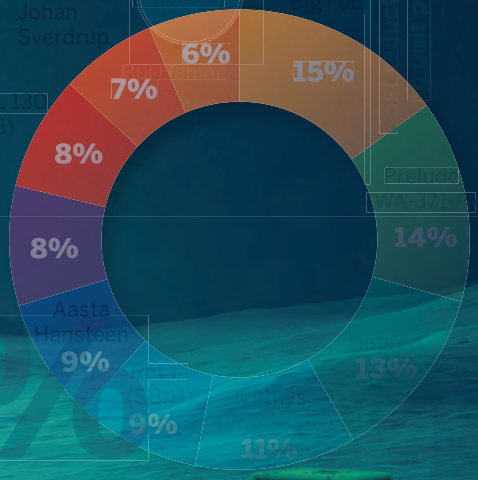
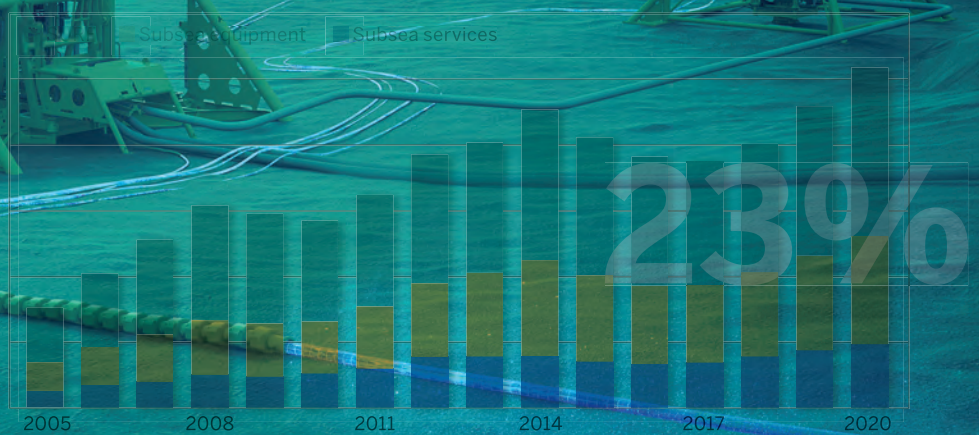
Global offshore market forecast

page 24

	Project	US$ millions	Region	Operator
1	Walker Ridge 029 Big Foot	653	US Gulf of Mexico	Chevron
2	Prelude (WA-371-P)	617	Western Australia	Shell
3	Hebron	538	Eastern Canada	ExxonMobil
4	Ichthys (WA-285-P)	490	Western Australia	INPEX
5	Rotan (SB-H)	382	Malaysia	Petronas
6	Aasta Hansteen	366	Norway	Statoil
7	Gindungo (Kaombo 1) (Block 32)	365	Angola	Total
8	Egina (OML 130 Ex OPL 246)	348	Nigeria	Total
9	Johan Sverdrup	293	Norway	Statoil
10	Buzios (Phase 3)	277	Brazil	Petrobras
	Grand Total	**4329**		





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Global Offshore Market Forecast

Photo from Aker Solutions.

Features

ON THE COVER

In the cards. While times are uncertain, one thing is clear: the future is subsea. And, that's why ***OE*** chose this illustration from Aker Solutions, depicting their subsea power distribution systems, as part of our January cover art.

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Departments & Columns

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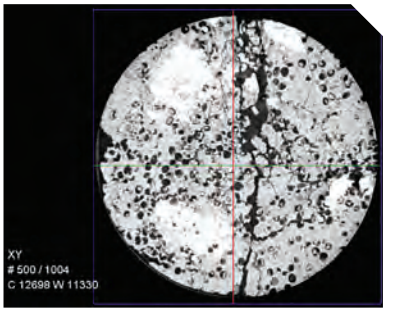

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(check one box only)

- ☐ 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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Online Exclusive

The Year in Review: 2015

OE takes one final look back at the year that was 2015, with our Top 10 online and magazine stories. Find it only on OEDigital.com.

Photo from SENER Facebook page

What's Trending

Big time

- Aker, Saipem join subsea forces
- Cameron stockholders say yes to Schlumberger merger
- Fugro wins Guyana survey

Photo from Aker Solutions

People

Woods named Exxon president

ExxonMobil has chosen Darren W. Woods to be president and a member of the company's board of directors, effective 1 January 2016. Woods is currently senior vice president of the corporation. Rex W. Tillerson will continue his roles of chairman of the board and CEO.

Activity

Shell, BG to shed 2800 jobs as merger clears

Shell has cleared the final regulatory approval for its US$70 billion acquisition of BG Group, after receiving "unconditional merger clearance" from the Chinese Ministry of Commerce. The plan to combine companies will mean the loss of 2800 jobs, or 3% of the two's combined global workforce.

Photo from iStock

Undercurrents

Ringing in the New Year

For the past 12 months, ***OE*** has done much reflecting on the past, as we lived through our 40th year as a publication. But, as we enter our 41st year, it is time to look ahead. And there is no better to time and place to do that than with our January Global Offshore Market Forecast issue.

OE reached out to several firms to get both the good news and the bad news about the year ahead. And there's no way to put the news delicately; we all know we're in for a tough year. The industry is battling oversupply, and bloated, high-cost projects that were difficult before the low oil prices made most projects uneconomical.

But, with every bleak forecast, there are those in the industry, those who have been through it all before, who hold the highest hopes for the betterment of our industry. And those people, like Rob Fast, Vice President, Offshore - Americas and West Africa for Hess Corp., are the ones who champion the idea of using the downturn to our advantage. Not just using the downturn to make cuts, but to innovate and dream-up the next generation of technologies that will take the industry further than it has ever been before. Rob explains how "lean" principles helped push forward Hess' Stampede project on page 36.

"Energy is what links the entire global economy," Berman said. "Much lower oil prices, are the only reasonable path to return the world economy to high growth and higher demand and have a balanced oil market."

Indeed, many analysts say conditions won't improve until 2017, maybe even 2018. But, time and tide wait for no man. Inaction on all fronts will end up hurting us in the end, and waiting for prices to return may not be the best solution.

Art Berman, an industry watcher, has a view on oil prices that likely many people do not hold: he feels prices need to be lower. "Prices have to fall further," he told a breakfast crowd in Houston this December. "We're below US$40/bbl now, the whole key here is to change investor/producer behavior."

Berman said the current downturn is part of a larger market issue. "The price collapse is nothing more than a devaluation of a market that was too high," he said. "High price and low demand leads to oversupply. And Berman blamed oversupply on "cheap money," caused by interest rates that have been kept artificially low, encouraging investors to look for a better yield in the oil and gas sector.

"Energy is what links the entire global economy," Berman said. "Much lower oil prices, are the only reasonable path to return the world economy to high growth and higher demand and have a balanced oil market."

Berman showed the audience a slide with historic oil price averages, saying that long-term oil prices since 1950 have averaged $45/bbl in 2015 dollars. Before 1974, oil prices averaged around $23/bbl. Berman insists that price trends will not increase until the surplus is reduced. But, he does believe that oil prices will recover faster than what most forecasts have predicted, but only if OPEC holds the line, allowing the market to correct itself.

As ***OE*** looks to the future of oil, we are pleased to introduce a new column for 2016 called "The Barrel," which will be written by Colin Welsh, CEO of Simmons & Company International Limited, as a way to help us help you keep tabs on the ever-changing oil market.

In addition, ***OE*** is also celebrating a subtle new look. Our last redesign was in 2013, and we felt like starting 2016 off in a new suit. We hope you enjoy our hip new threads. OE

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NEW IN 2016

The Barrel

Down, but not out

From an oil industry perspective it's difficult to find anything positive to say about 2015 other than I'm glad it's ended.

I certainly didn't see US$35 Brent crude coming, nor did I envisage such low prices looking like they will endure through 2016. The impact on oil service companies has been brutal with revenue declines in the 30% to 50% range devastating profitability and causing tens of thousands of employees to lose their jobs. The best companies cut costs hard early and cut again and again in an attempt to bolster the bottom line. Those slower to react paid a heavy price in terms of profitability, particularly those with high levels of debt.

"The mantra for oil service companies in 2016 must be to do everything possible to stay in business. This goes beyond cutting costs. It's about rethinking business processes and strategies."

Colin Welsh, CEO
Simmons & Company International Limited

The full force of the downdraft will be felt in 2016 as bank covenants are breached and equity values are compressed or obliterated. Banks will pass problem children on to specialist lending groups whose sole motivation is to recover as much of the bank debt as possible. At best, this results in companies spending more time on internal matters and less on winning new business. At worst, the company goes into a death spiral.

The mantra for oil service companies in 2016 must be to do everything possible to stay in business. This goes beyond cutting costs. It's about rethinking business processes and strategies. E&P companies are more open than ever before to new ideas if it means that they can reduce costs.

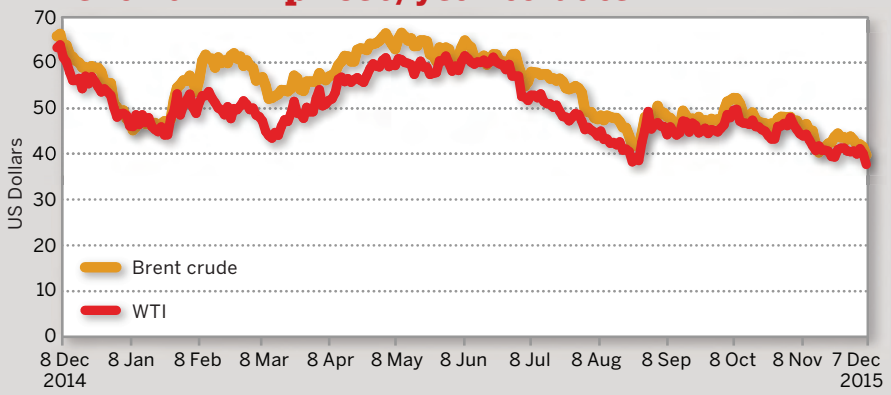
It's also time to consider combining businesses in order to remove overhead, enhance capability and build scale so that the business becomes more robust and can withstand a lower for longer downturn. The time to explore merger possibilities is definitely before a bank covenant breach. Once the bank specialist lending teams get involved the decisions pass out of the hands of the business owner.

As a glass half full person, I'd like to end with a couple of positive observations for the year ahead.

The longer term outlook for the industry isn't as bleak as most people forecast. The oil price will recover, but it will take time. Those companies that navigate the downturn to their advantage will be spectacularly well placed. The restructuring that is required in 2016 must be seen in this context and as an opportunity.

We might also see a surprise uptick in crude prices in the back half of 2016 as production declines in key US shale areas move into focus. And given the extent to which the brakes have been put on drilling activity you have to expect that production declines from conventional wells globally will be much higher than usual. Dial in the potential for the Middle East powder keg to impact production there and anything is possible. OE

Brent vs. WTI prices, year-to-date



Data acquired from Quandl on 15 December 2015.

Colin Welsh *joined Simmons & Co. in 1999 to establish the firm's Eastern Hemisphere business. Prior to joining Simmons, in 1987, Welsh established the Aberdeen office of RMD, a newly formed accountancy and corporate finance firm. Previously, he worked in both the London and Aberdeen offices of Touche Ross. Welsh graduated from Aberdeen University having studied economics, accountancy and law. He went on to qualify as a Scottish Chartered Accountant while working at Ernst & Whinney (now Ernst & Young).*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South Africa's port infrastructure is being advanced to accommodate the offshore oil and gas industry. Operation Phakisa, which was launched in mid-2014, provides an aggressive set of timelines to position the country's ports as premium destinations for rig and offshore support vessel repairs and maintenance. South African ports remain well-placed to provide other oil and gas related services to the growing industry on the east and west coasts of Africa.

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Port of Saldanha - South Africa's first oil and gas hub

The Port of Saldanha is geographically positioned on the west coast of South Africa and is one of the largest and deepest natural ports in Southern Africa. The port's infrastructure, ship repair facilities and offshore fabrication yard give the port an inherent competitive edge, making it ideal for services to this sector.

The port's geographical location will support the West and East African offshore oil and gas fields. The Off Shore Supply Base (OSSB), the Jetty at Mossgas and Berth 205 are the latest oil and gas initiatives to create dedicated and purpose-built capacity.

The recently launched Saldanha Industrial Development Zone situated at the back of the port will support the developing oil and gas and marine repair industry within and adjacent to the Port, offering a comprehensive and unique value proposition to the offshore oil and gas industry and catering for a seamless delivery of services to the industry.

The Port of Saldanha will play a leading role in the development of the oil and gas sector in Sub-Saharan Africa and in stimulating the blue economy.

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Global E&P Briefs

A Significant hit for W&T

W&T Offshore has made a "significant discovery" at the Ewing Banks 954 A-8 exploratory well in the deepwater Gulf of Mexico. The EW 954 A-8 well penetrated a total of 150ft MD of hydrocarbon pay contained in two sands. Completion operations are currently underway. Following facility tie-in, first production is expected during Q1 2016. W&T said that it anticipates producing the well from the two zones at a restrained gross rate of approximately 2300 boe/d.

B Murphy to P&A Thunder Bird

Murphy Oil encountered 75ft of hydrocarbon pay at its Thunder Bird sidetrack well in Mississippi Canyon Block 819 of the US Gulf of Mexico, but will plug and abandon the well due to the low oil price environment. The sidetrack reached the targeted Middle Miocene zone at a total depth of approximately 21,900ft.

C Eni to drill off Mexico

Italian explorer Eni will begin an exploratory drilling campaign in the Bay of Campeche offshore Mexico. Eni signed a new production sharing contract with Mexico's Comisión Nacional de Hidrocarburos of Mexico (CNH) for the Amoca, Miztón and Tecoalli oil fields. Eni said it will proceed with a delineation campaign by drilling four new wells, targeting a synergic and fast track development plan.

D Petrobras in new Espírito Santo find

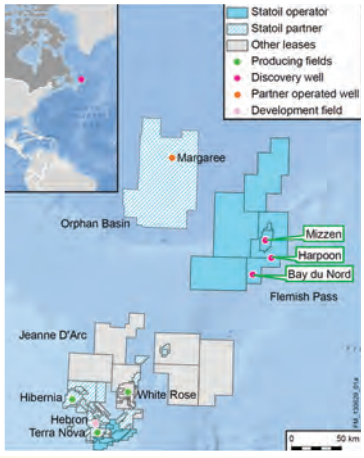
Brazil's Petrobras has hit a new oil discovery in the Espírito Santo basin. The discovery contains oil bearing sandstone layers amounting to a cumulative thickness of approximately 70m at a depth of about 4850m through appraisal drilling in the BM-ES-23 concession, which is 115 km off Espírito Santo state in southeastern Brazil, at 1800-2000m water depth.

F Furgo wins Fortuna survey

Ophir has contracted Fugro for a survey program at the Fortuna project offshore Equatorial Guinea. Fugro will deploy three of its specialist vessels – *Fugro Searcher, Fugro Scout* and *Fugro Frontier* – to perform autonomous underwater vehicle (AUV) surveys as well as geotechnical, environmental and metocean surveys. The Fortuna Project is to the west of Bioko Island, where Ophir is planning a large FLNG installation and associated subsea structures. Operations are scheduled for completion in January 2016.

E Bay du Nord appraisals advance

Canada's Husky Energy announced that the firm along with its partner Statoil plan to advance appraisal work on the Bay du Nord oil discovery offshore Newfoundland and Labrador, Canada. Since late 2014, the West Hercules rig has undertaken an appraisal program related to the Bay du Nord discovery in the Flemish Pass Basin. Appraisal activities are progressing as expected and will continue into early 2016, Husky said. Statoil estimates that Bay du Nord contains some 300-600 MMbbl of oil recoverable.



G North Tchibala 2-H begins production

Vaalco Energy's North Tchibala 2-H well has been brought online, at the Southeast Etame/North Tchibala (SEENT) platform offshore Gabon. The well was stabilized at 500 b/d, gross, free of H_2S and water. However, reservoir quality indicates higher flow rate potential. Vaalco is assessing productive capacity and will determine if remedial work will increase the flow rate. Vaalco is the operator of the Etame Marin permit area.

H Polarcus gets Denmark seismic work

Polarcus has received a letter of intent from Maersk Oil on behalf of the Danish Underground Consortium (DUC) for a 4D marine seismic survey offshore Denmark. The project will start Q2 2016 and will run for three months.

I Norway's 23rd round success

Norway's 23rd licensing round saw 26 oil and gas companies apply for rights to explore acreage in the Norwegian and Barents Seas.

The round comprised of 57 blocks or parts of blocks, of which three are in the Norwegian Sea and 54 in the Barents Sea. Wood Mackenzie says that applicants have been attracted to the acreage as it could hold over 2 billion bbl of new oil and gas reserves. Major oil and gas companies will view the Southeast Bar-

ents as a long-term strategic move, whilst taking advantage of reduced exploration costs afforded by the Norwegian tax system.

The Ministry of Petroleum and Energy plans to award new licenses in the 23rd licensing round before summer 2016.

K Israel makes way for Leviathan

The Israeli government has given Noble Energy the green light to move forward with the development of Leviathan and the Tamar expansion, despite a last attempt from the Israeli Forum for the Protection of the Coastline that petitioned the High Court to not approve the plan.

To proceed with Leviathan and Tamar, Noble has worked to advance technical work and negotiate gas sales agreements. The company is also updating and finalizing capital investment requirements, which will allow Noble to conclude external financing agreements required to reach final investment decisions (FIDs). FIDs for each project are estimated before the end of 2016, according to Noble.

The Leviathan Field is intended to produce and handle a maximum of approximately 1.6-1.8 Bcf/d of natural gas.

L BP increases WND interests

BP Egypt has completed acquisition of Hamburg-based DEA Deutsche Erdoel's interests in the North Alexandria Concession (22.75%) and in the West Mediterranean Deep Water Concession (2.75%).

BP's working interest in both concessions of the West Nile Delta (WND) project will increase to 82.75%.

The WND project agreement involves the development of 5 Tcf of gas resources and 55 MMbbl of condensates. Production from WND is expected to be around 1.2 Bcf/d, equivalent to about 25% of Egypt's current gas production. All the produced gas will be fed into the country's national gas grid. Production is expected to start in 2017.

M Iran offers $30 billion in projects

Iran has offered 52 oil and gas development projects in addition to 18 exploration blocks at its Tehran IPC Conference.

The projects, estimated to be worth more than US$30 billion, include 29 new and currently producing oilfields and 23 gas developments.

N Rosneft completes geological work

Rosneft has completed its 2015 geological exploration program using 2D seismic survey methods coving 20,434km in the Kara Sea, Chukchi Sea, and Laptev Sea, and 3D seismic covering 2710sq km in the Pechora Sea and the Sea of Okhotsk.

J Edvard Grieg achieves first oil

First oil has started from the Edvard Grieg field. The field is part of PL338 on the Utsira High in the North Sea, about 180 km west of Stavanger, and contains 187 MMboe gross 2P reserves. Oil is being transported via the Grane pipeline to the Sture terminal in Norway, while gas will be transported via a separate pipeline system to Scotland.

Development drilling with the Rowan Viking jackup rig will resume shortly and a total of 10 production wells and four water injection wells are planned to be drilled with plateau production expected during 2H 2016. The drilling is expected to continue into 2018.

Lundin Norway (50%) is the operator of PL338 with partners are OMV Norge (20%), Statoil (15%) and Wintershall Norge (15%).

Global E&P Briefs

Rosneft has also constructed two development wells in the Sea of Okhotsk and completed geological engineering surveys in the Pechora Sea (at the Yuzhno-Russky license area). Furthermore, joint ventures of Rosneft and Statoil, carried out geological engineering surveys at two licenses in the Sea of Okhotsk (Magadan-1 and Lisyansky) in support of the 2016 exploration drilling program.

O CNOOC, Husky sign PSC

China National Offshore Oil Corp. (CNOOC) signed a production sharing contract (PSC) with Husky Oil Operations for Block 15/33. The block is located in the Pearl River Mouth basin in the South China Sea, covering 155sq km with a water depth of 80-100m.

According to the terms of the PSC, Husky will be the operator during the exploration period and conduct exploration activities in which all expenditures incurred will be borne by Husky.

Once entering the development phase, CNOOC has the right to participate in up to 51% of the working interest in any commercial discoveries of the block.

P Lundin spins bit on Imbok-1

Lundin Malaysia spud the Imbok-1 exploration well in blocks SB307 and SB308, in shallow waters off East Malaysia. The West Prospero jackup rig will drill Imbok-1 to a total depth of 1700m below mean sea level. Drilling is expected to take 30 days.

Q KrisEnergy busts on Mustika-1

KrisEnergy has completed the Mustika-1 exploration well in the Sakti production sharing contract (PSC) in the East Java Sea.

Mustika-1 was drilled to 2667ft total vertical depth subsea, and encountered gas in the Tuban and Kujung I formations. Wireline logs indicate that the gases have high CO_2 content and therefore are likely to be below the economic threshold for a commercial discovery. The well will be plugged and abandoned and a detailed analysis of the well data and gas samples will be undertaken to review the remaining prospects and leads in the Sakti PSC.

R Polarcus starts Vulcan survey

Polarcus began a new RightBAND multi-client project over the Vulcan sub-basin, off the North West Shelf, Australia. The survey will comprise a minimum 4000sq km.

Processing will be done by DownUnder GeoSolutions through a broadband Pre-SDM workflow and final processed data will be available from Q3 2016 with Pre-STM fast track data available from Q1 2016.

S Quadrant spuds Roc-1

Perth-based Quadrant Energy has spud the Roc-1 well offshore Western Australia, according to partner Carnarvon Petroleum. Drilling is expected to reach 4700m total depth, and take about 35-40 days to complete. Well logging and sidewall coring is expected to take about 5-10 days on success case.

Quadrant operates license WA-437-P (40%) along with. partners Carnavon Petroleum (20%), JX Nippon (20%), Finder Exploration (20%).

Contracts

Statoil awards Johan Sverdrup pipeline contracts

Statoil has awarded contracts for the linepipe, coating and pipe installation of the Johan Sverdrup export pipelines estimated at slightly less than US$288 million (NOK 2.5 billion).

Mitsui & Co. Norway, awarded the linepipe fabrication contract, will deliver 220,000-tonnes of steel for the oil and gas pipelines, totaling 430km. Linepipe production will start early in 2016.

Wasco Coatings Malaysia was awarded the contract for external anti-corrosion treatment and concrete weight coating for the oil and gas pipelines, as well as internal flow coating for the gas pipeline. The work will be performed at Wasco's factory in Malaysia in 2017.

Saipem, awarded the oil and gas pipelaying contract, is scheduled to start pipe-laying operation in the spring of 2018, using the *Castorone* vessel.

Technip awarded Odd Job projects

Technip has been awarded a lump sum contract by Deep Gulf Energy II for work on the ultra-deepwater Odd Job development in the Mississippi Canyon area of the US Gulf of Mexico.

The contract consists of project management and engineering services; fabrication and installation of about 23km of pipe-in-pipe flowline and about 2km of steel catenary riser (SCR); design, fabrication and installation of in-line sled, flowline end termination; fabrication of jumper; and pre-commissioning for the flowline and SCR system.

Technip's operating center in Houston will manage the overall project. The offshore installation will be performed summer 2016 by Technip's *Deep Blue* vessel.

KCA Deutag wins two BP contracts

Drilling and engineering contractor KCA Deutag has been awarded two contracts with BP Exploration (Caspian Sea) worth about US$360 million for the initial contract or $1 billion including all options.

The first contract is for the operations and maintenance of seven platforms operated by BP in the Caspian Sea pursuant to product sharing agreements. The initial term is for three years with two, three-year extension options.

The second is for engineering support services on all drilling packages for projects in the Caspian Sea that are operated by BP from the Azerbaijan, Georgia and the Turkey Region. This contract is effective from 1 December 2015 to 30 September 2017 with two extension options of one year each.

DOF Subsea bags NZ gig

OMV New Zealand has awarded DOF Subsea an IMR contract, where the scope of work includes inspection and work on eight mooring lines on the Maari field's FPSO, *Raroa*, offshore New Zealand. The offshore phase of the project will be carried out during 1H 2016, and the vessel *Skandi Hercules* will be utilized under the contract. With this award, the Skandi Hercules is firm with IMR work up until end Q3 2016.■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Giving ABK a boost

Abdelghani Henni reports on how French major Total is keeping the ABK field offshore Abu Dhabi up and running past its initial life span, and beyond, serving as a pilot project for other major fields in the country.

Big fields get bigger, or so the saying goes. While Total's Abu Al Bukhoosh (ABK) field offshore Abu Dhabi, in the United Arab Emirates (UAE), isn't among the biggest in the region, it does prove the adage.

French major Total was granted a concession to develop the ABK field in 1972. At that time, the field's life span was estimated at 15-20 years, but, after almost 40 years, the field is still producing with an overall recovery rate at around 45%, reaching 70% in places, due to technologies Total has tried and continues to try on the field.

Total ABK, a wholly-owned affiliate of Total, continues to operate the field today, with current production at around 120,000 boe/d, 10,000 bbl of which is oil, and around 110,000 boe of gas.

The field lies offshore, on the border between the UAE and Iran, where the Abu Dhabi side of the field produces oil and gas, while the Iranian side currently produces only oil. "The geographical location makes the field very important," says Hatem Nuseibah, President Total E&P UAE and Group Representative in the UAE, due to political tensions between Iran and the UAE.

Hatem Nuseibah

Like many other fields in the region, ABK's reservoirs are carbonate, but also harsh environment, with high-pressure and high-temperature.

Total's partner on the ABK field, the Abu Dhabi National Oil Co. (ADNOC), has set an ambitious plan to increase the recovery rate of its fields to 70%. Total believes this could be possible at ABK and as a result if its belief in the field, well before ADNOC's targets, a range of technologies have been tried on the ABK field to boost production and increase recovery rates, with successful results.

"For example, if you look at the recovery rate, today in ABK, the overall recovery rate is more than 45%, and in some reservoirs are 55%, and there is one reservoir where we have achieved 70% recovery rate. Today, it produces around 10,000 b/d at 92% water cut [across the whole reservoir]," Nuseibah says.

Gas injection

"The first solution was the tertiary gas injection," says Maurice Lescoeur, geology and geophysics manager at Total ABK.

In fact, Total was one of the first to apply EOR technology within the UAE, Lescoeur says. "Total ABK has seen some of the first applications of EOR (enhanced oil recovery) technology within the UAE, with the first pilot for tertiary gas injection was carried out in 1992 and followed by full field application of gas injection in 1997," Lescoeur says.

"We started tertiary gas injection in the earlier 1990s, and we did the first EOR pilot project in 1992," Nuseibah adds.

A key success factors for tertiary gas injection program at ABK field was a comprehensive analysis of subsurface mechanisms, though some reservoirs are very complex and conditions within some reservoirs make certain technologies inappropriate to use, i.e. exhibiting extreme high temperatures and pressures.

The tertiary gas injection technique has been responsible for 28% of production from the reservoir over the past 20 years. But it hasn't been the sole means of increasing recovery in the field.

"We were producing a large amount of water with the gas from ABK field, so we tried ways to do artificial lift," Nuseibah says. So far, 95% of the wells at ABK field are gas lifted, with wells completed with multiple gas lift, side pocket mandrills. Both work, but it also means deci-

ABK field infrastructure offshore Abu Dhabi. Photo from Total.

Nuseibah says. "We initiated lab studies for chemical EOR in 2010, where we developed a suitable surfactant and polymers for high sulfur (240 g/l) and high temperature (83^{O} C, 181°F)," Lescoeur adds.

From 2011-2013, Total's team worked on selecting which well in the reservoir they would use for a single well pilot, as well as designing the offshore injection facilities. That led to the offshore pilot. "In 2014, we started pilot execution and we continued laboratory work to improve chemicals, while in 2015 we worked on the way forward and a multi-well pilot," Lescoeur says.

The chemical EOR pilot project in ABK field has changed the perception of this type of EOR in the UAE. Not only did the 2014 trial lead to 40% additional recovery at the pilot well, it also lead to drop of residual oil saturation from 40% to 5%. "The chemical EOR project is particularly interesting as it uses polymers and surfactants that have never been used in such hot, saline conditions within a carbonate reservoir," Lescoeur says. "This was a complex project completed safely on time."It is in this area Total is looking to do further work at ABK, especially with recent technical advances in the industry. The company plans to accelerate chemical EOR deployment, reduce the cost of pilots, with a focus on standardization, modularization, compactness and flexibility.

In addition to chemical EOR, the company has also investigated enzyme EOR, but found out that it is not economic. "We are also studying further methods of EOR, like sweet water, and we are studying all other different types of EOR to pilot in ABK," Nuseibah says. "It's not enough to have a present development plan, we should come up with additional development plans related to EOR that can include gas injection, already used in ABK, CO_2 injection and chemical injection," he says. Smart water could also be looked at, Total has said, as well as expending the tertiary gas injection technique, which has been such a king pin for the field.

These are some of the main technologies used on ABK. Total has also deployed electrical submersible pumps (ESPs) and dual ESPs, intelligent completions, multi-lateral wells, splitter wells, and dump-flood to selective completions. It also deployed ocean bottom cables to gather seismic data, 3D vertical seismic processing (VSP) and gas tracers.

Given the age of the facilities, which has led to other initiatives such as the first composite wrap on a subsea pipeline for a Total facility, field management is a daily challenge at ABK. But, it's also proving a prime technology testing ground and improving recovery rates at ABK could have wider implications for other carbonate fields in Abu Dhabi.

"Everything that is done with ABK field, can be used as a pilot project for other major fields in Abu Dhabi," Nuseibah says. "Therefore, ABK is a sort of a pilot field for all of Abu Dhabi reservoirs." OE

Total Management welcomed apprentices of the Total ABK Academy in Abu Dhabi. Staff photo.

sions have to be made on a daily basis regarding allocation of available gas for injection into the reservoir for enhancing recovery versus its use for gas lift.

The latest work on the field, however, has been chemical EOR. "We also did some pilot projects with chemical EOR, and we had interesting results,"

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Pain in the Annulus

Well plugging and abandonment activity as part of offshore decommissioning is starting to ramp up – but could it be done better? Elaine Maslin reports.

Decommissioning is a place no operator wants to go, but, it has the potential to be big business and it's a task one no one can afford to ignore.

In 2014, globally, there were some 12,000 facilities, including floating facilities, platforms and subsea structures, according to Brian Twomey, managing director, Reverse Engineering Services, all of which will eventually need decommissioning.

But, the main cost in decommissioning is the well plugging and abandonment (P&A). According to 2015 estimates by industry body Oil & Gas UK, well P&A accounts for 46%, or nearly half the cost of decommissioning. That's 3% higher than the last estimate, made in 2014, by the same body in its annual Decommissioning Insight report.

Over 1224 wells are due to be P&A'd alone in the UK North Sea over the next decade, at a cost of about US$11.5 billion (£7.7 billion), representing 30% of the 4300 wells on the UK Continental Shelf (UKCS). This is also an increase on the previous years' estimate, which was some 930 wells over the next 10 years at a cost of $9.6 billion (£6.4 billion).

The scale of the task is just as daunting on the Norwegian Continental Shelf, which will have an estimated 7000 wells that will have been or need to be P&A'd by 2050, according to a 2014 report by the University of Stavanger. Wells take 21-125 days to P&A. Using 10 rigs, with zero downtime, it could take more than 57 years to perform P&A on all these wells, the report points out.

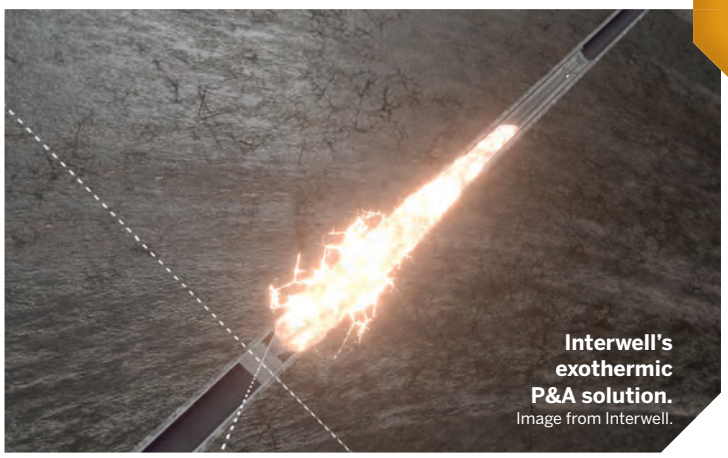
A global challenge

Globally, there is also a huge offshore well stock and it's increasing, including deepwater wells, which will attract even greater costs. To date, there are about 1400 deepwater wells, Twomey said, speaking at the Oil & Gas UK and Decom Offshore's Offshore Decommissioning conference in St Andrews, Scotland, late 2015. One deepwater well recently abandoned offshore Brazil cost a "number which will dwarf any of your [North Sea] wells," he says. "Just in Brazil alone, the well P&A is enormous," he adds. "The same situation is developing in Angola and West Africa. We are doing a lot of work in South Africa and they got a real shock how expensive it is to do well P&A."

The issues are legion in P&A. On the Ivanhoe and Rob Roy field decommissioning project, Hess spent between 17 and 117 days per well on P&A, the Offshore Decommissioning conference heard, highlighting the range in scope on different wells.

"In some parts of the world you're dealing with hazardous materials such as mercury," Twomey told the conference. "This is a problem no one really knows a solution to. If you get organic mercury it's almost impossible to get it out. You can't just fill it with concrete and it will seep out. There are many issues like this emerging." So, is the industry going about how it P&A's wells the right way? It wouldn't seem so. Some of the issues are organizational.

Per Jahre-Nilsen.
Photo from DNV GL.



Interwell's exothermic P&A solution.
Image from Interwell.

Mixed standards

	Number of plugs	Minimum length (m)
Norway	2	100
UK	2	~30
Netherlands	1	100
Germany	1	100
USA (BSEE)	2	~30
Canada (land)	1	~8
Russia	1	~24
Australia	1	~30
Malaysia	1	~30

ConocoPhillips and BG Group outlined to the Offshore Decommissioning conference how they have been working on new organizational structures for decommissioning. Shell has learned the hard way on its massive Brent decommissioning project, which started in 2006, with P&A work beginning in 2008.

"Key lessons are making sure you have the correct organization that's fit for purpose," Duncan Manning, Brent Decommissioning Project manager, told the conference. He also cited transition planning, looking at batch operations and, what might seem obvious, making sure the rig is ready for P&A operations and what alternatives there might be. "Starting a P&A campaign without knowing what is in those wells is something we will not be doing again," he added.

Risk-based P&A

But, significant savings could be made by taking a risk-based approach to P&A design, says Per Jahre-Nilsen, business development leader, Drilling & Well, DNV GL. At the moment, the industry takes a prescriptive approach, using the same method to P&A wells, from high-pressure wells to dry holes, as

In-Depth

Quick stats

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

New discoveries announced

Depth range	2012	2013	2014	2015
Shallow (<500m)	70	73	72	45
Deep (500-1500m)	23	19	29	15
Ultradeep (>1500m)	37	35	13	12
Total	**130**	**127**	**114**	**72**
Start of 2016 date comparison	130	127	114	72
	-	-	-	-

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	27	333.28
Deep	11	1204.00	1595.00
Ultradeep	42	11,837.25	13,193.00
United States			
Shallow	11	66	134
Deep	20	1082.27	1048.48
Ultradeep	25	3262.50	3270.00
West Africa			
Shallow	129	4191.72	16,948.62
Deep	40	5862.50	6650.00
Ultradeep	17	2150.00	2610.00
Total	**295**	**29,656.24**	**45,449.10**
(last month)	(269)	(25,458.52)	(42,715.70)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	990	35,927.10	465,953.91
(last month)	(893)	38,368.59)	(511,820.04)
Deep	147	10,106.43	129,592.62
(last month)	(120)	(7184.58)	(70,643.91)
Ultradeep	94	17,630.15	70,170.00
(last month)	(83)	(15,648.25)	(31,097.00)
Total	**1231**	**63,663.68**	**665,716.53**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	42,126	(42,137)
Planned/ possible	24,738	(24,618)
	66,864	(66,755)
8-16in.		
Operational/ installed	83,417	(83,497)
Planned/ possible	49,666	(49,627)
	133,083	(133,124)
>16in.		
Operational/ installed	93,956	(93,860)
Planned/ possible	43,625	(45,424)
	137,581	(139,284)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	273	(275)
Construction/ Conversion	47	(47)
Planned/possible	323	(321)
	643	(643)
Fixed platforms		
Operational	9258	(9269)
Construction/ Conversion	101	(104)
Planned/possible	1384	(1382)
	10,743	(10,755)
Subsea wells		
Operational	4843	(4859)
Develop	437	(401)
Planned/possible	6512	(6535)
	11,792	(11,795)

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	14,567.01	35,876.75	26,249.12	19,774.61	17,290.76	27,318.11	27,533.24
(last month)	(14,528.45)	(38,085.01)	(24,057.70)	(19,846.90)	(19,400.16)	(27,209.30)	(-)
Deep	4469.26	4254.74	2323.73	2221.55	4512.78	6285.88	17,650.08
(last month)	(4469.26)	(4340.71)	(2237.76)	(2262.04)	(4512.78)	(6285.88)	(-)
Ultradeep	2342.81	2037.21	2978.59	3287.44	5515.17	7449.12	10,771.31
(last month)	(2342.81)	(2037.21)	(2978.59)	(3287.44)	(5509.17)	(7318.54)	(-)
Total	**21,379.08**	**42,168.70**	**31,551.44**	**25,283.60**	**27,318.71**	**41,053.11**	**55,954.63**

Statoil's Huldra platform, which has been used to help verify DNV GL's P&A guidelines, and resulted in 30-40% well P&A cost savings. Photo from Statoil/Kjetil Alsvik.

set out by industry standards, i.e. Norsok and others, he says. Yet, the regulations in Norway and the UK set out a risk-based approach.

There is also very little consistency from basin to basin on standards. In Norway, the UK, and the US, the standards set out having two plugs, across 100m, 30m and 30m, respectively, he points out. In the Netherlands and Germany it is one plug across 100m. Australia and Malaysia say one plug across 30m. What's more, Jahre-Nilsen says, well P&A concepts date back to early onshore practices, which were adapted for the offshore in the 1970s and have change very little since.

"When these methods were developed we had little understanding of marine life, ocean currents etc.," he told an Intsok/Scotland Development International event in Aberdeen late November. "With our increased knowledge and understanding [on a site specific basis] we can probably reduce the number of plugs and the overall length and use different materials because we can say something about the probability of that well leaking and what the impact might be. This means that hazardous wells will get the attention they deserve and benign wells will avoid excessive rig-time and expenditure."

DNV GL has been working with Statoil for two years developing the new approach and trialing it on the Huldra well P&A program, offshore Norway, as a form of verification, with positive results. It has saved 30-40% costs, Jahre-Nilsen says, reducing the number of well barriers. The guidelines were officially launched in November.

Norway's Sintef, a research organization, is also looking into P&A challenges. Dr. Malin Torsæter, a research scientist from Sintef discovered there was a lack of well plugging data, or efforts towards P&A technology research and development in 2013. But, she says, there is also a significant potential market here for those willing to create new technologies.

"The global potential means there is a huge opportunity for this business," she told the Intsok/Scottish Development International event, hosted at Aker Solutions offices in Aberdeen. Torsæter agrees that taking a prescriptive approach to well P&A is wasteful and also says that new technologies are needed. Work needs to be done to find technical solutions to today's problems, such as finding logging tools which can see through steel pipes to assess integrity in order to be able to place a plug, she says.

"80% of P&A time is spent on cement and steel removal, because the integrity of that cement and steel cannot be assessed," Torsæter says. Pulling pipe out of wells also needs to be simplified, she says.

Others agree it is time to do things differently. A joint report by Oil & Gas UK and Decom North Sea, *Adoption of Novel Solutions Report 2015*, says, in well P&A, intervention in the wells typically uses the same tools used when the wells were drilled and that P&A campaigns would reduce costs.

Sintef is looking at different cements, which would be able to work with the tubing left in the hole, and developing multi-tasking tools to reduce the number of trips down hole, as well as long-term monitoring at the sand face. The latter is being tested as part of a long-term pressure test using CO_2 in Germany, which aims to test, or prove, current standards.

Jahre-Nilsen says other materials to cement are also being looked at, such as epoxy. Interwell has been working on a solution which would melt the materials in the well to create a plug using an exothermic reaction, Jahre-Nilsen points out. This would be a quantum leap, he says. Interwell is working the technology towards qualification with an objective to release it to the market by 2H 2016.

Sintef is also creating a wells data base, in order to help the Norwegian put a "price tag" on the task, which, ultimately, tax payers have to pay a significant proportion (78%) of, as in the UK (50-75% in tax relief), making P&A costs a matter of public interest. Sintef also has a project looking at "Shale as a barrier," which is considering if shales etc., could close the hole themselves and if so how tight would the hole be.

Sharing experiences is also key, according to the *Adoption of Novel Solutions* report, especially where operators have been able to use a sustained campaign approach to reduce costs. Yet, as Torsæter found in 2013, information isn't that easy to come by. A P&A campaign which involved a number of the operators on the UKCS was transformed thanks to one operator sharing their previous P&A well data. Yet, despite the acknowledgement of how useful this information sharing was, neither the campaign nor the operator was named at either event this was mentioned at.

There is no time to lose, however, as activity in this area is ramping on the UKCS. The number of wells P&A'd on the UKCS has tripled over the last five years and there are due to be some 900 wells P&A'd up to 2023, according to Colette Cohen, Senior VP Centrica Upstream UK and Netherlands, speaking at the Offshore Decommissioning conference, citing figures from UK-based consultants McKinsey & Co.

It would also seem like an opportune time, with rig rates low as units sit idle. Yet, the Norwegian Petroleum Directorate has warned against a suggestion made in the basin to plug wells to keep rigs busy, requesting that thought is given to reuse first. Nothing is ever simple. OE

FURTHER READING

Read Oil & Gas UK's Decommissioning Insight 2015 report: http://oilandgasuk.co.uk/decommissioninginsight.cfm

Read Oil & Gas UK's Adoption of Novel Solutions report: http://oilandgasuk.co.uk/wp-content/uploads/2015/11/Adoption-of-Novel-Solutions-Report-2015.pdf

£16 billion UKCS decommissioning spend to 2024: http://www.oedigital.com/component/k2/item/10890-16-9-billion-ukcs-decommissioning-spend-to-2024

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	109	85	24	77%
Jackup	399	286	113	71%
Semisub	151	110	41	72%
Tenders	31	19	12	61%
Total	690	500	190	72%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	37	35	2	94%
Jackup	23	6	17	26%
Semisub	19	14	5	73%
Tenders	N/A	N/A	N/A	N/A
Total	79	55	24	69%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	15	6	9	40%
Jackup	118	76	42	64%
Semisub	35	15	20	42%
Tenders	20	12	8	60%
Total	188	109	79	57%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	21	7	75%
Jackup	52	38	14	73%
Semisub	31	28	3	90%
Tenders	2	1	1	50%
Total	113	88	25	77%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	48	42	6	87%
Semisub	43	32	11	74%
Tenders	N/A	N/A	N/A	N/A
Total	91	74	17	81%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	109	88	21	80%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	114	91	23	79%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	21	2	91%
Jackup	23	17	6	73%
Semisub	11	9	2	81%
Tenders	9	5	4	55%
Total	66	52	14	78%

Eastern Europe

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

Source: InfieldRigs
14 December 2015

Bringing subsea projects

Jon Fredrik Müller and Audun Martinsen, of Rystad Energy, take a look at rising costs and the downturn and share how these two will affect the subsea market going forward.

With high development activity and cost inflation in the industry since 2010, the breakeven prices for subsea developments have increased significantly. With cost levels as in 2014, many of the discoveries not yet sanctioned would be unprofitable at the current oil price regime. So how are the costs reacting to this downturn?

The oil market is currently oversupplied resulting in a sluggish oil price. Going into 2016, Rystad Energy believes the oil price will continue at the levels seen in 2015 and trade in the range of US$35-60/bbl (Brent). However, from 2017 the market balance is forecasted to improve as supply responds to lower prices, and demand is forecasted to continue to grow. Moving towards 2020 the oil price is expected to strengthen significantly, potentially reaching the same price level as seen in 2014 ($100 real).

In terms of supply capacity, the oil and gas industry differs from other industries. In most other industries, one can maintain an established production capacity with a small amount of maintenance. However, the inherent production decline within oil and gas fields results in large continuous investments needed, just to keep production flat at the current level. To be able to grow production and in order to meet growing global demand, significant investments will be required towards 2020. In terms of production growth, there are mainly two sources of growth possibilities – shale/tight and offshore resources. It is Rystad Energy's view that it is not a question of one or the other. We need production growth from both sources to be able to deliver on projected demand by 2020.

Cost reductions

The reduction in offshore activity, in conjunction with growing capacity in many of the offshore segments like rigs, platform supply vessels (PSVs) and anchor handling

“in the money”

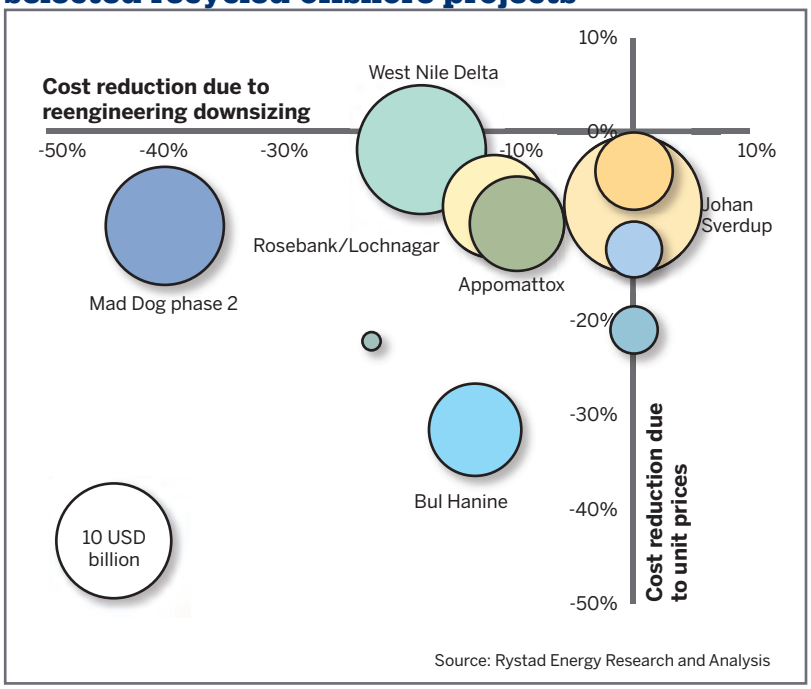
tug supply (AHTS) vessels, have hit the suppliers hard. Companies are reorganizing, cutting costs and reducing staff, and as a result unit prices are coming down. The cost reduction varies greatly from segment to segment, but overall the cost compression within offshore segments is in the range of 10-25%.

Within offshore rigs, one of the segments that has been hit hardest, rates for large deepwater rigs have come down around 50%. Within the subsea segment, there has also been an increasing number of joint ventures aimed at bringing down costs through increased cooperation between the subsea production systems (SPS) producers and installation companies.

The intense focus on cost cutting among exploration and production (E&P) companies resulted in several development projects put on hold in late 2014 and into 2015. In 2014, Rosebank (Chevron) and Mad Dog phase 2 (BP) were some of the projects that got hit as companies could not prioritize new large cost commitments. Not all projects were cancelled, as they showed potential for significant production additions to a portfolio of falling offshore production. Instead, projects were reassessed for their potential of downsizing or re-engineering in order to cut costs. While this happened, the oil price was falling towards and below the $50 mark. Consequently, investments were cut to a minimum, which, in the end, led to decreasing pricing power among service companies and unit prices started to trend downwards.

An illustration of the Johan Sverdrup field center.
Image from Statoil.

Fig. 1: Cost impacts for selected recycled offshore projects



Source: Rystad Energy Research and Analysis

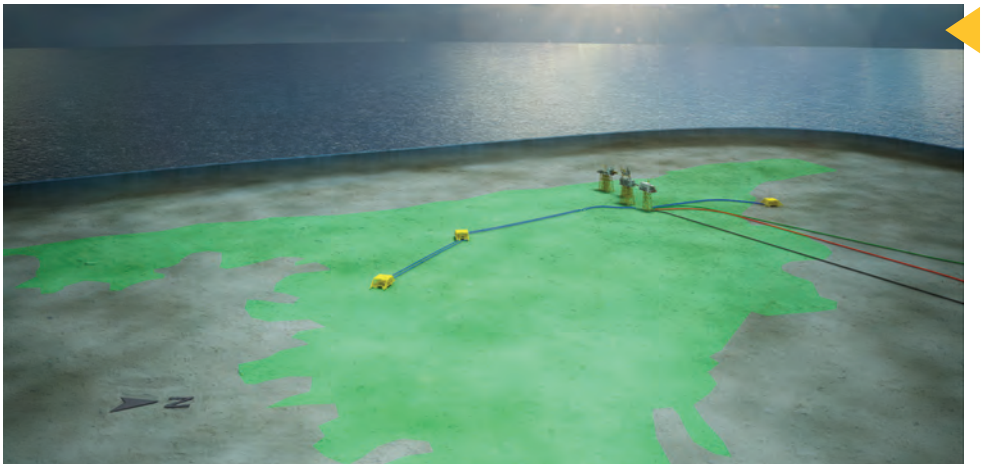
Subsequently, this has led to a large cost saving potential for the previously shelved projects and Rystad Energy now observes offshore projects to come in at an average of 10-30% lower costs than before the oil price crash.

Figure 1 shows selected offshore greenfield projects that have been recycled or obtained new greenfield cost estimates based on either re-engineering, downsizing or lower service unit prices. As shown, E&P companies have accomplished cost savings of up to 50%, both due to re-engineering and cost reductions. The BP-operated Mad Dog phase 2 is an example where simplification of design and project phasing has translated to cost reductions of close to 40%, however, the recovered volumes will likely be reduced as well. Another example is the giant Statoil-operated Johan Sverdrup development, which has been able to cut more than $1 billion on lower unit prices alone.

Cost reductions have had a dramatic effect on breakeven prices. Prior to the oil price drop, undeveloped offshore projects had an average breakeven price of around $70/bbl. Assuming that a “typical” offshore project’s costs can be reduced by 20% due to cost savings, yields a new breakeven price closer to $55/bbl. The cost compression will significantly enhance the competitiveness of offshore resources, and projects that were not economical a year ago, might now be “in the money” due to cost compression.

Subsea market

Although Rystad believes that offshore will be an important source of supply growth towards the end of the decade, the



An illustration of the Johan Sverdrup field's subsea layout.
Image from Statoil.

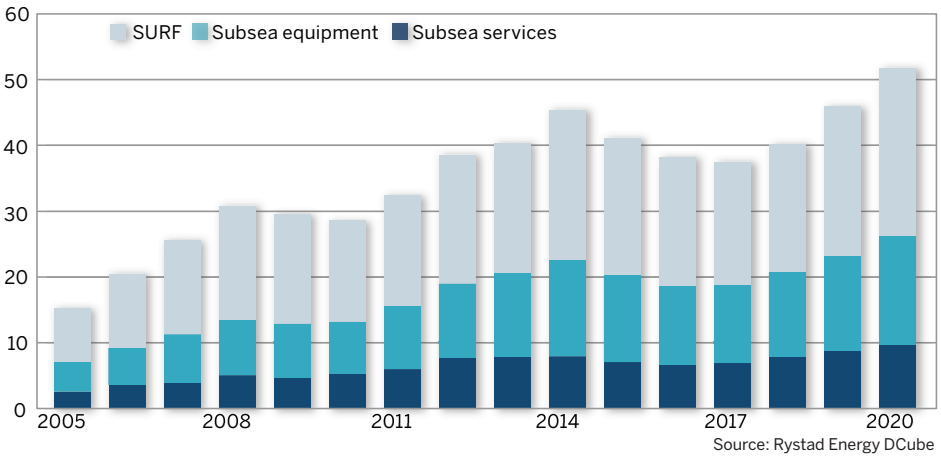
current oversupply has impacted offshore investments for the remainder of the market. The short-term activity has been significantly reduced as operators have pushed the brakes and cut back on investments in order to improve cash flows in the low oil price environment. However, the cost compression in the industry is improving the profitability of subsea projects. Figure 2 shows historical and forecasted subsea expenditure (capex and opex) split by market segment. The market has contracted approximately 10% in 2015 compared to 2014 levels of $45 billion. The negative trend is forecasted to continue in 2016 and stabilize in 2017. However, with a tightening of the market balance foreseen in 2017, expenditure in the subsea segment is expected to grow from 2018 reaching $52 billion in 2020, a compounded annual growth rate of 11% from 2017-2020. This is a growth slightly less than the previous growth cycle from 2010-2014 of 12%, and far behind the 25% growth experienced leading up to the financial crisis in 2008.

Figure 2 also illustrates how the different subsea segments are affected differently by the downturn. The subsea services segment, which is primarily subsea inspection, repair and maintenance, is a more stable segment driven by operational expenditure. The SURF (subsea installation, umbilical, riser and flowline) and subsea equipment segment (production systems like Xmas trees and manifolds), which are primarily driven by investments in greenfield developments, fluctuate more and are affected harder by the downturn and project postponements.

The current market downturn is forecasted to be both deeper and longer than the downturn experienced during the financial crisis. The reason for this is that while the financial crisis was a demand driven downturn, the current

downturn is driven by an oversupply, which takes longer time to correct. However, Rystad Energy believes that the market balance on oil will become increasingly tighter from 2017 onwards and with the addition of lowered unit costs, the subsea industry is set for a new growth cycle from 2018. OE

Fig. 2: Global E&P subsea expenditure
(capex and opex, US$ billion) by market segment



Source: Rystad Energy DCube

***Jon Fredrik Müller** is a senior project manager within the consulting department of Rystad Energy, based in Oslo. His main area of expertise lies in the oil field service segments and particularly within offshore related services. He holds a M.Sc. in Industrial Economics from Norwegian University of Science and Technology with specialization in mechanical engineering and finance, including a graduate exchange program at University of Calgary.*

***Audun M. Martinsen** is the product manager and lead analyst of oil field services at Rystad Energy. His fields of expertise include the global offshore and onshore oil service market, E&P cost analysis and supply and demand studies. He holds a MS in marine engineering from the Norwegian University of Science and Technology and University of Berkeley, California. He has broad experience within the E&P and oil service industry with previous engagements at Coriolis, Shell and BW Offshore where he has worked as a lead engineer, product developer, system consultant and analyst.*

The floating production market: 2016 & beyond

While depressed commodity prices lend to pessimism, floating production systems are projected to remain an integral component of offshore field development. Quest Offshore analyst Andrew Jackson explains.

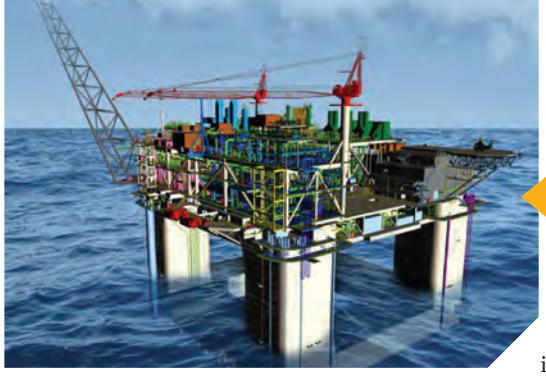
The drilling rig support module is removed from its barge by the Saipem 7000 and lifted onto the Mad Dog rig on 13 March 2012. Image from BP.

Throughout 2015, one has not had to look far for dire news and projections on the outlook for the offshore industry. Falling oil prices, reduced operator expenditures, and project deferrals became overriding themes. Despite near-term challenges, however, floating production systems (FPS) will remain an integral component of the offshore development mix with several high-profile projects in the works.

2015 – A year in review

As the industry has adapted to falling crude prices, several floating production project awards were postponed outright, re-designed, or re-bid as operators and the supply chain worked to make proposed developments more cost competitive. As a result, 2015 floating production awards, as of 1 December 2015, saw a total of two floating production, storage, and offloading (FPSO) vessels, one semisubmersible, one floating storage and offloading (FSO) vessel, and one floating LNG unit awarded, which is roughly one quarter of 2010's awards.

Malaysia's Yinson will provide a newly converted FPSO, presently under construction at Keppel Shipyard, for deployment at Eni's OCTP-Sankofa development. The second award encompasses the redeployment of an existing unit, Rubicon Offshore's *Front Puffin* for service at Yinka Folawiyo's Aje development. Shell's Appomattox semisubmersible hull will be constructed by Samsung Heavy Industries in South Korea with the topsides fabricated in the Gulf Coast at Kiewit in Ingleside, Texas. Modec is also providing an FSO under an en-



An illustration of BP's Mad Dog Phase 2 semisubmerible, designed KBR/GVA, which the designers say is inspired by BP's Atlantis platform. Image from KBR.

gineering, procurement and commissioning contract with Maersk that will see the unit constructed by SembCorp Marine in Singapore for the high-pressure, high-temperature Culzean project in the UK sector of the North Sea. Furthermore, Golar LNG exercised their second option with Keppel to construct the third GoFLNG, the *Golar Gandria*.

The final month of 2015 provides slight potential for further floating production awards by yearend. Eni's Coral South FLNG (Mozambique), Talisman's Ca Rong Do tension leg platform and FPSO (Vietnam) and Husky's Madura MDA-MBH FPSO (Indonesia) are presently tendering. It is, however, very unlikely that all three of these projects award before yearend, with Quest's present mean case forecast accounting for the probability of 1-2 further units in 2015.

Table 1: FPS Projects – 2016 Award Potential

Operator	Project	Province	FPS Type
BP	Mad Dog Phase 2	US Gulf of Mexico	Semi
BP	Hopkins	US Gulf of Mexico	Semi
Shell	Vito	US Gulf of Mexico	TLP
Pemex	Ayatsil-Tekel	Mexico	FPSO
Sonangol	Cameia	Angola	FPSO
Shell	Bonga SW/Aparo	Nigeria	FPSO
Eni	Etan/Zabazaba	Nigeria	FPSO
Namcor	Kudu	Namibia	FPSO
Woodside	Browse FLNG	Australia	FLNG
CNOOC	Liuhua 11-1	China	FPSO
CNOOC	Liuhua 11-1	China	TLP
CNOOC	Liuhua 16-2	China	TLP
Santos	Ande Ande Lumut	Indonesia	FPSO
Octanex	Ophir Oilfield	Malaysia	FPSO*
Shell	E6 SK 308	Malaysia	FPSO*
Shell	Penguins Redevelopment	UK	FPSO
Karoon	Kangaroo/Echidna EPS	Brazil	FPSO
Petrobras	Libra Pilot	Brazil	FPSO
Petrobras	Sepia	Brazil	FPSO
Premier Oil	Sea Lion 1a	Falkland Islands	FPSO
ExxonMobil	Liza Early Prod. System	Guyana	FPSO

* Indicates projects likely to utilize an existing, leased FPSO
Source: Quest Offshore – Floating Production Database (QFPD)

2016 – FPS award candidates

For 2016, Quest's projects a moderate improvement in FPS awards compared to 2015 as operators and the wider supply chain better adjust to commodity price conditions, cost deflation improves project economics, and development projects delayed from earlier years come to fruition.

BP's Mad Dog phase 2 development provides an optimistic example of a project that has seen its fair share of delay during a period of elevated crude prices but appears to be a strong candidate for a 2016 final investment decision and FPS award. The project was originally focused on a spar design coined "Big Dog," which was put on hold in April 2013, due to the technical complexity of a heavy topsides and cost concerns. BP has since simplified the FPS, now based on a KBR/GVA semisubmersible design, and has been able to significantly lower project development costs to below US$10 billion, according to Upstream Chief Executive Lamar McKay in BP's Q3 2015 results. Earlier cost estimates for the project employing the Spar were ~$20 billion.

In addition to the three projects mentioned previously, there remains several FPS projects with award potential in 2016 (see Table 1).

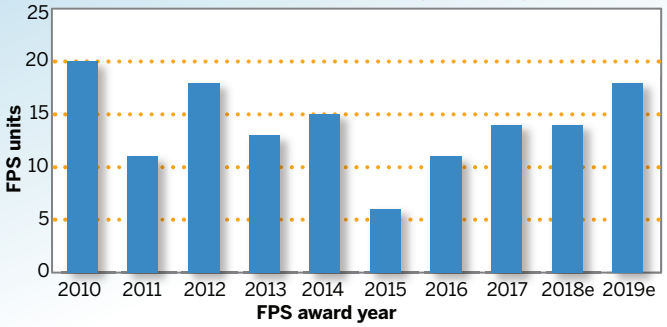
While the above projects present near-term potential based on current development status and operator plans, it is unlikely that all come to award within 2016. Quest's proprietary forecasting methodology is constructed to discount these opportunities and account for potential delays with 11 FPS units forecasted for 2016 award in the mean (middle) case. OE

Andrew Jackson *serves as Quest Offshore's market research & database manager, where he works with the Quest Research Team to conduct research & analysis on offshore project development. Jackson graduated from Texas A&M University with a BBA in Information & Operations Management.*

Looking forward–Quest's FPS forecast

In the longer-term, Quest's FPS forecast projects a tough year for 2016 with a steady improvement to historical averages by 2019, with as many as 18 units forecasted to award in 2019. In 2010, 20 units were awarded representing a recent peak in award activity supported by the award for replicant units in Brazil for Petrobras. While the total number of awards is approaching this figure, it is worth noting that the project composition is further leveraged toward smaller FPS systems and phased developments while recent history had a greater composition of large, standalone units. While this might seem like a negative indicator, it does show that industry is successfully recalibrating project plans to maintain development amidst more challenging industry conditions.

Quest floating production mean case forecast (Dec 2015)



Source: Quest Offshore – Floating Production Database (QFPD)

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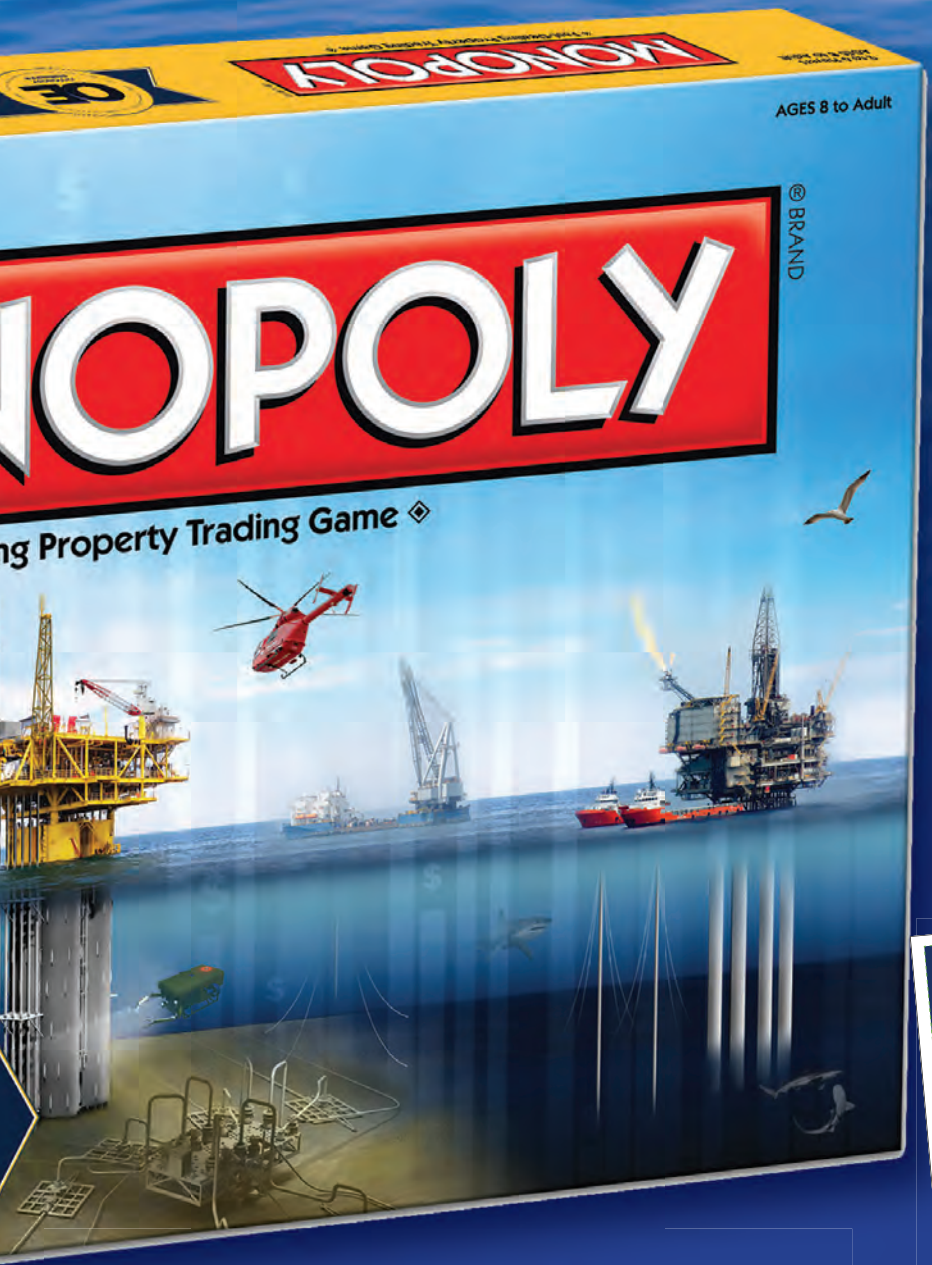

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First cut is the deepest

_OE_ reached out to analysts Wood Mackenzie and IHS Energy to find out the view on the next 12-18 months. And the outlook is not so great for exploration spend. Audrey Leon and Elaine Maslin report.

Wood Mackenzie

Andrew Latham, VP upstream consulting, at analysts Wood Mackenzie, says we can expect to see less exploration in 2016, across the board, although the jury is still out on how the national oil companies will respond in the current oil price environment.

"Everybody is doing less exploration than they were and the small companies have cut back sharper relative to the majors," he says. "The overarching theme is one of a retreat from frontiers, the most obvious being the Arctic. But, we are still seeing deepwater exploration. The jury is out on is the national oil companies, especially those that invest internationally. They have not yet cut that deeply, but there is a thought that they might."

So where are explorers aiming their drillbits? Unsurprisingly, heartlands or established basins, where there is existing infrastructure so that smaller discoveries can have higher value, Latham says. "Shell, for example, is having a good run in Malaysia, and Eni has been drilling in the Congo in shallow water plays. Areas of the North Sea are coming into that as well, for example Apache, in the Central Graben recently."

While new discoveries in North Sea heartland areas are significant for Apache, they will not be transformative for the basin. But, there is drilling likely in more high impact areas, such as offshore Brazil, he says.

"More activity is also likely along the coast from Brazil," he says, such as offshore Guyana, where ExxonMobil made the 2015 Liza discovery – one of the 10 biggest finds in 2015. 2016 might also see the first well spud offshore Uruguay, Latham says.

Other high impact areas include Mauritania, following large discoveries there by Kosmos Energy and Cairn Energy – both of which were also listed list in the top 10 discoveries of 2015 – particularly as there's a belief there could be oil, as well as the discovered gas, there.

The Eastern Mediterranean will also remain a hot spot, says Latham, as well as deep water offshore Egypt, as Eni looks to appraise its massive Zohr discovery – another 2015 top 10 discovery. "A gas play is also emerging in the Black Sea, and we will see more drilling there," Latham says. "All of these, excluding Uruguay, have discoveries or proven hydrocarbons," says Latham, "and they are not super high cost exploration provinces."

The areas that will lose out are the likes of Greenland or the Kara Sea and even ultra-deep gas plays in the US Gulf of Mexico, as well as rank unknown frontiers. But those areas deemed difficult to work in are also slipped back, such as the Australian Bight, and the sub-basalt plays West of Shetland, which are difficult and high cost, as well as the Barents Sea,

where exploration results have been mixed.

Meanwhile, areas where there have been high levels of exploration, will also fall off the exploration radar, as the focus moves towards commercialization, such as East Africa, where giant gas discoveries were made offshore Tanzania and Mozambique in recent years.

As we move into 2017-2018, the results from the recent, strong offshore Newfoundland round, including drilling commitments, might start to bear from, says Latham, as well as offshore Mexico.

A wild card could be future prospects for floating LNG, as a development solution for small scale resources in basins where the potential for onshore LNG trains isn't attractive. "This is getting some attention in parts of the world that don't have challenging maritime conditions, specifically West Africa, Cameroon, Equatorial New Guinea with the likes of Ophir and Perenco," says Latham. Golar LNG, a partner on both, is confident there is plenty more to come.

-Elaine Maslin

IHS Energy

For explorationists, the next 12-18 months will be a difficult road. For most companies, exploration is the easiest to cut if you are looking to reign in capex, says Rebecca Fitz, a senior director for IHS Energy. She explains: "There are very few near-term consequences (to cutting exploration spend). Cuts to development spend, in contrast, result in near term cuts in production growth expectations. IHS expects these deep cuts to continue into 2016. "We (IHS) did a study, a couple months ago, where we looked at the top 18 most successful deepwater exploration companies over the last five years. Their exploration spending is expected to fall about 50% (from 2013-2015). That's significant, even for the most successful companies, at exploration," Fitz says.

Fitz explains that one implication of exploration cuts are certain companies will continue their transition toward asset development, such as UK-based Tullow and Brazilian national oil company Petrobras. "This places the onus on a new set of explorationist to drive new play de-risking," she says.

So for the companies who are still drilling, where are they headed? Fitz says they are staying on familiar ground. "There will be less focus on frontier exploration, and new play incubation," she says. "We would instead expect the bulk of exploration efforts to focus on pre-existing core areas and programs, such as the Gulf of Mexico, Sub-Saharan Africa, and other established petroleum provinces. Chance of failure is high in a frontier programs, while established infrastructure positions in core areas tends to facilitate more rapid development—and potentially better economics—of new discoveries in these areas." OE

-Audrey Leon

Workers on the West Gemini rig, supporting the CLOV project.
Photo from Total/Gonzalez Thierry.

Top projects by expense for 2016

No. 1 – Chevron's Big Foot

Coming in at No. 1 on Infield System's list of highest capex projects for 2016 is the Chevron-operated Big Foot field in the Walker Ridge block 29, US Gulf of Mexico. According to Infield Systems data, the supermajor will spend US$653 million on the problem beset field in 2016.

Strong loop currents in the Gulf of plagued the field, which originally delayed Chevron from towing the platform to the site. Then, in June, work to install the Big Foot tension leg platform (TLP) was suspended after nine of the 16 tendons lost buoyancy, in an incident that is still under investigation. As of August, Chevron said it does not expect to achieve first production from Big Foot until 2018.

The seven remaining tendons have since been uninstalled and the TLP has been towed back to Kiewit Offshore Services' facility in Ingleside, Texas.

The Big Foot field, which Chevron operates with 60% interest, along with partners Statoil (27.5%) and Marubeni Oil & Gas (12.5%), was discovered in 2006, and is estimated to contain total recoverable resources of approximately 200 MMboe. It is the sixth deepwater facility in the Gulf of Mexico for Chevron. ▪

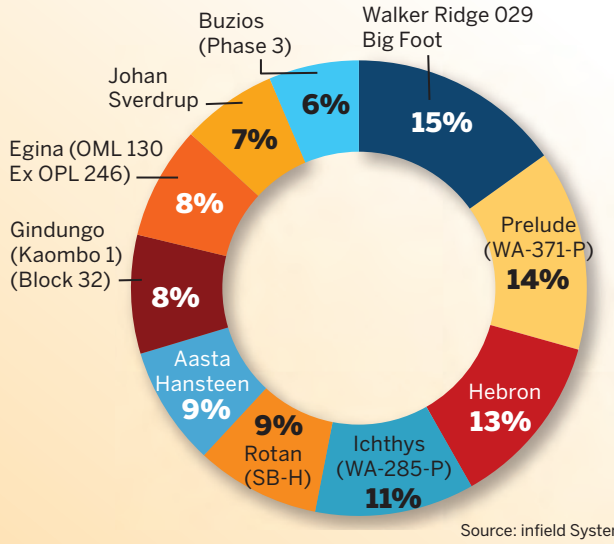
Infield System's top 10 highest capex projects currently under development in 2016

	Project	US$ million	Region	Operator
1	Walker Ridge 029 Big Foot	653	US Gulf of Mexico	Chevron
2	Prelude (WA-371-P)	617	Western Australia	Shell
3	Hebron	538	Eastern Canada	ExxonMobil
4	Ichthys (WA-285-P)	490	Western Australia	INPEX
5	Rotan (SB-H)	382	Malaysia	Petronas
6	Aasta Hansteen	366	Norway	Statoil
7	Gindungo (Kaombo 1) (Block 32)	365	Angola	Total
8	Egina (OML 130 Ex OPL 246)	348	Nigeria	Total
9	Johan Sverdrup	293	Norway	Statoil
10	Buzios (Phase 3)	277	Brazil	Petrobras
	Grand Total	**4329**		

Chevron's Big Foot platform being towed to Walker Ridge. Photo from Chevron.

Chevron's Big Foot platform being towed from Korea to Texas on Dockwise's Mighty Servant I vessel. Photo from Dockwise.

Top projects by percentage



Source: infield Systems

In July 2014, the Hebron GBS was towed to the Bull Arm deepwater construction site. Photo from ExxonMobil Canada Properties.

No. 3 – ExxonMobil's Hebron

Coming in at No. 3 on the list is the ExxonMobil-operated Hebron heavy oil project off Newfoundland and Labrador, Canada. Infield Systems says ExxonMobil and its partners will spend some $538 million on the project in 2016.

First oil is set for 2017. The field, which sits in the Jeanne d'Arc basin about 350km southeast of St. John's, was discovered in 1980 and will become the fourth producing field in the province. It is estimated more than 700 MMbbl of recoverable resources will be produced from the field.

Hebron will be produced through a gravity based structure (GBS), with 150,000b/d production capacity from 52 well slots, and about 1.2 MMbo storage capacity.

The GBS has been towed to the Big Arm deepwater construction site to be completed before it is installed at the Hebron field. ▪

No. 5 – Murphy's Rotan

Ranking at No. 5 is the Murphy Oil-operated Rotan gas field in block H of the Sabah basin, offshore Malaysia. Infield Systems' data shows that Murphy will spend $382 million on the project, which is on track for achieving first gas in 2018. The field, estimated to hold reserves of around 950 Bcf, will be produced through a Petronas floating liquefied natural gas facility, the PFLNG-2.

In early November last year, Petronas announced that the keel for the PFLNG-2 facility had been laid in Geoje Island, South Korea. The facility is being built by a consortium of JGC Group and Samsung Heavy Industries. In June 2015, Petronas held a steel cutting ceremony for the facility at SHI's yard. The Malaysian oil major said the keel laying signifies the formal recognition of the start of the group's mega construction phase of the PFLNG2 with a collective weight of 134,000-tonne. In addition, Aker Solutions has been chosen to deliver a subsea production system for the field. The award will include four subsea wells, a hub manifold, in-line tees, a connection system and production control system, and first deliveries are expected in Q2 2016. Murphy Oil operates block H and Petronas will operate the PFLNG-2. OE

First steel was cut for Petronas' FLNG-2 facility in Geoje, South Korea in June. Photo from Petronas.

Offshore's **opportunity?**

Innovate, collaborate, standardize; lead with lean.

One could argue that the future of the global offshore E&P business, particularly deepwater development, is ours to create. Confronted with the steep decline in oil prices and weak outlook for near-term recovery, the industry must pull together to navigate the current down cycle. Rather than wait for prices to rebound, we need to proactively drive efficiency and create value with the objective to reduce costs and cycle times, while keeping safety the top priority. Operators, contractors and suppliers must innovate, collaborate and standardize—or as we say at Hess, lead with lean.

"While the challenges are immense, we need to remember the path forged by our predecessors. Most innovations were achieved during low oil prices."

Rob Fast, Vice President, Offshore - Americas and West Africa, Hess

By most accounts, the future demand for oil is huge; and so is the investment required. To meet demand, an estimated US$1.3 trillion is required to develop global deepwater resources between 2015 and 2030. Given that an estimated 75% of new deepwater development projects are uneconomic below $70/bbl, the challenge is to reduce costs by about $25/bbl to make these projects competitive with other supply sources such as tight oil.

While the challenges are immense, we need to remember the path forged by our predecessors. Most innovations were achieved during low oil prices. For example, hydraulic fracturing, 3D seismic and floating production facilities. The average price of oil since 1900 has been low—about $35/bbl, adjusted for inflation. Much of the bloat in deepwater development costs over the last decade was self-inflicted, due largely to unneeded complexity and customization of industry kit.

Innovate, collaborate, standardize

For more than a hundred years, innovation has been a key enabler of our success. We must continue to drive innovation every day. We can and are transforming subsurface characterization (through improved 3/4-D seismic and integrated modeling), modernizing drilling techniques (through improved modeling, optimization and real-time monitoring), improving facilities design/operability, and leveraging crossover technologies (through applications such as advanced data analytics, medical and defense technology applications, etc.).

Collaboration is another area we can improve. For example, sharing logistics support across installations, rather than allowing under-utilized helicopters and empty vessels sailing past competitors' platforms. Existing facilities ullage can be better utilized to reduce capital investment and improve returns. Imagine the potential efficiencies we can capture through cooperation across the value stream from design, engineering, construction, operations, through abandonment!

Standardization is another large value-creation opportunity. Design complexities and custom spec choices have driven offshore development cost increases by an estimated 50% versus early 2000's designs. Countermeasures include adopting common designs for topsides and floating structures, applying standard well designs/components, and utilizing common SURF equipment including subsea trees. Hess is currently cooperating with other operators to agree subsea tree design standards, in order to capture improved inventory management, and reduce cycle times and cost.

Lead with lean in low-cost environment

Hess believes disciplined application of the lean management system will be a competitive differentiator. We are leveraging lean to create a high-performance culture based upon continuous improvement principles. Onshore, we applied lean to reduce Bakken drilling and completions costs by 58% in three years. Now, we are applying these techniques offshore. Hess' Stampede deepwater development project in the Gulf of Mexico is leveraging lean to deliver first oil safely, on time and on budget in 2018. For example, working as one team, Hess and Kiewit Offshore Services used lean problem solving techniques to transform the process for fabricating the blast wall. Rather than "stick building" in place, the wall was assembled indoors, in a horizontal configuration as a single unit. This approach eliminated working at heights, reduced environmental impact, and improved weld quality. The blast wall was completed two months ahead of schedule, with 50% fewer man hours, and with reduced EHS exposure. The Stampede project is demonstrating how lean management practices learned onshore can be applied offshore.

Summary

Oil and gas are essential to human survival and growth. Offshore resources are plentiful; however development costs are marginal to uncompetitive versus alternative supply sources. The offshore industry has an opportunity to compete through innovation, collaboration, and standardization. Let's get after it! **OE**

Rob Fast *is vice president, offshore – Americas and West Africa, Hess Corp. Fast, who has more than 29 years' experience in a variety of technical and executive management roles, oversees the company's assets and deepwater projects in the Gulf of Mexico, Equatorial Guinea, and Ghana.*

Prior to joining Hess in 2009, Fast held positions at Exxon Mobil Corp., Aera and Mobil Oil Corp. Fast holds a bachelor's degree in petroleum engineering from the University of Tulsa and is a registered professional engineer in California.

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African FPSOs

Nigeria is eying an opportunity to integrate floating production units on home turf, potentially even building them from scratch. Elaine Maslin found out more.

LADOL from the air.
Photos from LADOL

West Africa is one of the world's floating production hot spots. Already home to a large fleet of operating floating production, storage and offloading vessels (FPSOs), more are on the way, with deepwater projects planned by Total, Chevron, ExxonMobil, Eni and others.

The growth in the floating production market both off Nigeria and neighboring countries' coasts has not been lost on both investors and regulators in the country.

Nigeria's Lagos Deep Offshore Logistics base (LADOL) is eying the FPSO vessel construction market. It wants to first perform vessel integration, but ultimately, it wants to be a fabricator. The organization, backed by private, Nigerian investors, has spent US$300 million on new fabrication facilities and is already working on Total's *Egina* FPSO contract, under a joint venture with Samsung Heavy Industries, fabricating modules due to be integrated onto the vessel before it is deployed offshore Nigeria.

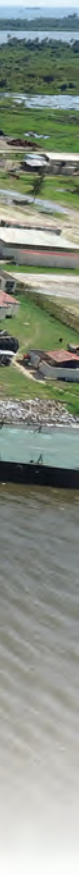
Is the idea that far-fetched? Angola has been trying to achieve the same aim. The country, also home to a string of deepwater FPSO developments, recently saw the FPSO *N'Goma* berth at its Porto Amboim Estaleiros Navais yard (Paenal yard) at Port Amboim. The vessel, already an FPSO, which was being converted to work on Block 15/06 offshore Angola, had two modules fabricated and then integrated at Paenal. Major upgrade work to the hull, turret and integration of new and refurbished topsides was done in Singapore. Paenal was opened in 2008, as a joint venture between national oil company Sonagol and SBM Offshore (*OE: October 2014*). Paenal's first FPSO integration project was on Total's *CLOV* FPSO, which came on stream last year (*OE: July 2015*).

Dr. Amy Jadesimi

In both countries, local content requirements have been a strong driver towards increasing FPSO fabrication work. "The local content act was passed in 2010. One of the things made obligatory through the new law was onshore FPSO fabrication and integration in Nigeria," says Dr. Amy Jadesimi, managing director, LADOL. "This is something Nigeria has been trying to do for decades, because it is such a game changer. If you cannot accommodate something like this [FPSO fabrication] in Nigeria, it is always going to be hard to get local content above 10%."

What's more, while Nigeria has had an oil and gas industry for 50 years, the only other significant yard in country is Saipem's at Port Harcourt.

Samsung started working with LADOL in 2011. The partnership, LADOL hopes, will help introduce and embed



the expertise and knowledge the country has lacked, in turn creating a center of gravity for the industry.

A 120,000sq m facility with a 500m-long quay wall area has been created at LADOL, with the capacity to fabricate about 1000-tonne/month, Jadesimi says. Because of its location, the facility can handle up to 10,000-tonne modules, whereas before this had been limited to 500-1000, Jadesimi says.

"This changes the market in West Africa, we will be able to do projects Africa could not do before, and it takes Nigeria to the next level," Jadesimi says. "Because we can do these very large projects, it will stimulate investment to increase demand for fabrication."

A quay wall will be ready in Q1 2016, with the *Egina* FPSO due to arrive sometime in the next 12 months "or so." Work fabricating some of the offshore modules for the FPSO has already started. Jadesimi was unable to be more precise about the date or about the exact percentage and breakdown of the work packages, other than that the hull will be partially integrated in Korea then modules will be built in Nigeria and the integration completed at LADOL. She says the project, "from our side," is on schedule. Jadesimi hopes that by the third FPSO project, the full integration work will be done in Nigeria. Longer term, there could be the potential to build a drydock, she says.

Jadesimi admits the technology and knowledge transfer will not happen overnight. The aim is that, over 10 years, expertise will be transferred to local staff, starting with 90% technology and knowhow from Samsung.

This, and the need to pay off the investment in the facilities, will mean one project is not enough to pay off the investment in the facility, so LADOL will be looking for more work. Jadesimi thinks it will be there, with major projects waiting in the wings, including a potential expansion of the Shell Bonga project and ExxonMobil's Bosi field. Both appear to have been slowed, by both low oil prices, but also Nigeria's Petroleum Industry Bill, which is still unsettled. But, Jadesimi says there are a lot of smaller fields that could require infrastructure, and which could open a market for FPSO refurbishment at LADOL, as well as potential life-extension projects. LADOL will also look to serve the broader West African market and potentially beyond that, if it can.

Jadesimi also thinks they can have a positive impact on costs. "We want to see how we can benefit small fields and help reduce costs on FPSOs," she says, by having fabrication and integration more local to projects. "Throughout the next 10 years the cost of these FPSOs will be coming down because it will be cheaper to do it closer to the field."

LADOL's project has faced both skepticism that it could work and also a legal wrangle over local content. But, Jadesimi is confident they can succeed: "There is a market large enough to justify this infrastructure investment and we are confident going forward it will be used because of the oil and gas act. The drop oil price will slow down new markets and bring back interest in to Nigeria because it is more developed. But we also expect to see more exploration and production in new countries in West Africa as well." OE

FPSOs: On the horizon

While the oil price has sucked much wind out of the sails of the FPSO industry, work must go on. And there are still quite a few projects lined up from 2016-2018. Infield Systems presents this list of conversion and newbuild construction projects.

FPSOs currently under conversion

FPSO name	Tanker conversion/refurbishment	Installation year	Location
Aje FPSO (Phase 1) (Ex Front Puffin)	Refurb	2016	Nigeria
Atlanta EWT FPSO (Petrojarl 1)	Refurb	2016	Brazil
Buzios P74 FPSO	Tanker Conversion	2017	Brazil
Buzios P75 FPSO	Tanker Conversion	2019	Brazil
Buzios P76 FPSO	Tanker Conversion	2017	Brazil
Cabaca FPSO (East Hub 15/06) Armada Olombendo	Refurb	2017	Angola
Cameroon FLNG FPSO (GoFLNG Hilli)	Tanker Conversion	2017	Cameroon
Kaombo Norte FPSO (Block 32 GGC) (Ex Olympia)	Tanker Conversion	2017	Angola
Kraken FPSO (Ex Prisco Alcor)	Tanker Conversion	2017	UK
Lapa Pilot FPSO Cidade Caraguatatuba MV27	Tanker Conversion	2016	Brazil
Layang FPSO (Deep Producer 1) (Ex Laurita)	Refurb	2016	Malaysia
Libra EWT (Phase 1) FPSO (Ex Navion Norvegia)	Tanker Conversion	2017	Brazil
Lula Alto FPSO (Cidade de Marica)	Tanker Conversion	2016	Brazil
Lula Central FPSO (Cidade de Saquarema)	Tanker Conversion	2016	Brazil
South Pars (Oil) FPSO	Tanker Conversion	2017	Iran
Teluk Berau A FPSO Replacement (Brotojoyo)	Tanker Conversion	2015	Indonesia
TEN FPSO Mills MV25 (Tweneboa/Enyenra/Ntomme)	Tanker Conversion	2016	Ghana
Walker Ridge 508-A FPSO Stones (Turritella)	Tanker Conversion	2016	USA
Madura Strait BD FPSO (Armada Madura)	Tanker conversion	2016	Indonesia

FPSOs currently under construction (newbuilds)

FPSO name	Installation year	Location
Egina FPSO	2017	Nigeria
Ichthys FPSO	2016	Australia
Lula North P67 FPSO	2018	Brazil
Lula Sul P66 FPSO	2017	Brazil
Moho Nord FPU Barge FPSO	2016	Congo (Brazzaville)
Petronas PFLNG-1 FPSO (Labuan)	2016	Malaysia
Petronas PFLNG-2 FPSO	2018	Malaysia
Prelude FLNG FPSO	2016	Australia
Schiehallion FPSO-2 (Quad 204) (Glen Lyon)	2016	UK
Western Isles FPSO (Sevan 300)	2017	UK
Catcher FPSO	2017	UK

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Tackling the backlog

With many assets now more than 25 years old, asset integrity is a daily concern on the UK Continental Shelf. Is the industry keeping up? Elaine Maslin reports.

Rope access is used to get to areas usually out of reach. Photo by Craig Hannah.

When the North Sea started its first offshore production in 1975, some 40 years ago, it was with a view that the industry would be fairly short lived and certainly not still going well into the 2000s.

Yet, despite the current market challenges facing the industry, many facilities are still running long after their original cessation of production date and they will be expected to continue for years to come. As a result, asset integrity has been and remains a big topic. But, has the industry got a grip on it?

According to figures from Oil & Gas UK, the safety critical maintenance backlog has been creeping up year-on-year since 2010, amid US$100/bbl oil prices. Its Health & Safety Report 2015 puts the safety critical back log at an average 8900 man-hours per installation for 2014, divided into 2200 man-hours planned maintenance backlog per installation (2009: 500 man-hours per installation), 2700 hours of corrective maintenance backlog (2009: 750) and nearly 4000 hours of deferred maintenance backlog (2009: 700).

At the same time, the number of companies reporting their backlog KPIs (key performance indicators) has fallen, according to the 2015 report, and there is uncertainty around the quality of the data supplied, with work now ongoing to find ways to validate its accuracy.

Falling efficiency

Over a similar period, production efficiency, an indication of how well assets perform compared to how well they could perform, has been falling, from just above 80%, in 2004, to about 65%, in 2014, according to latest figures, presented at the Energy Institute's Asset Integrity Conference in Aberdeen in late 2015. According to Gunther Newcombe, who presented the figures, unplanned production losses – as opposed to planned, export, and reservoir losses or well work – accounted for about half of the decrease in production efficiency from 2009-2014.

Newcombe is director of exploration and production at the new independent regular in the UK, the Oil and Gas Authority (OGA). He says there are operators currently with production efficiency at less than 20%, with just seven out of 29 UK Continental Shelf (UKCS) operators, with production efficiency over 80%, and it's the majors who are most likely to be at the bottom of the table. Over the same period, production has fallen, from more than 3.4 MMboe/d to just under 1.5 MMboe/d in 2013.

So are these data linked?

"Safety critical maintenance backlog has increased from just above 700 man hours per installation to more than 4000, as at Q3-4 2014, with the increase having started from 2010, and the greatest rises in 2013 and 2014. Meanwhile, unplanned losses account for the greatest increase in the lost production efficiency, with planned shutdown time also increasing," Newcombe says.

Russell Breen, operations manager, energy division, Health and Safety Executive (HSE), told the event: "The safety critical backlog has steadily increased from 2010… [from] well before oil price dropped. If anything, the oil price is going to make it worse."

Alternate view

The data appears pretty stark. Is there more to it? According to some, the rise in the backlog from 2009 has been due to greater focus on asset integrity, following on from the HSE's work in this area, both in asset integrity and aging and life extension (ALE). This meant more work is being found and listed than before, accounting for some increase in the numbers and potentially showing a positive trend towards addressing maintenance. It's also thought that some operators have become conservative in how they report their safety critical back log – i.e. reporting more than they should, as under reporting the back log would get them in trouble with the HSE.

Indeed, in the same period, the industry has a high level of safety, compared to other industries, suggesting its issues around asset integrity are not about safety.

Also, so-called Level 1, 2 and 3 findings lodged by the HSE on its inspections have fallen. Level 2 are issues which wouldn't have a great impact and Level 3 are those which could have a significant impact. According to Breen, HSE data shows the average number of open level 2 findings per installation has halved, from about 14 in 2008, to about seven in Q3 2014. The total number of open level 3 findings, across all installations, has also fallen, from about 35 in 2008 to 12 in 2014, suggesting an improving picture, in terms of impact of installations.

The number of hydrocarbon releases has also fallen by 48%, after a campaign to reduce them by 50%, the OGA showed. But, talk to others and it's described as sheer complacency.

Enforcement

The level of backlog hasn't passed the authorities by. Late-2014, the HSE issued an enforcement notice to an operator purely due to its huge maintenance backlog on one platform.

Judith Hackitt, the HSE's CEO, said the notice was served because of their "massive maintenance backlog." She said: "The operator had "very clearly had not given any thought to the cumulative impact of this huge backlog on their overall safety integrity." HSE confirmed that the operator involved was BP and the notice, served November 2014, related to the Bruce facility.

BP is not alone in struggling with its backlog. "The reality is, the industry hasn't done a good job over the last 20 years of maintaining offshore infrastructure," an industry professional told *OE*.

To try and get a grip on the work required, HSE says operators should get a better understanding of the type, level, and extent of maintenance required and the impact of failing to maintain it, have clear plans to deliver that maintenance, the necessary supervisory and engineering support, inspections and audit to ensure competent delivery and robust verification of safety and environmentally critical elements.

But, Breen says: "I think first we need to get consistent handle on what we are measuring here and we then need to know what we are doing and what we need to do to be able to approach it."

Work in progress

Both the Energy Institute and Oil & Gas UK (OGUK) have issued asset integrity management and ALE guidelines and OGUK is working with the industry on cost efficiencies and ways to better coordinate shutdowns.

The OGA is also focusing on asset stewardship, under one of the new body's eight boards, led by Newcombe and Nexen Petroleum UK operations director Ray Riddoch. An enhanced asset stewardship strategy is being developed, to be published in Q1 2016, with two areas already chosen for specific attention: reducing the amount of time dedicated to vessel inspection and managing corrosion under insulation (CUI). New technologies will have a key role to play in this area, as well as risk-based maintenance management approaches, condition-based monitoring and improved leak detection, Newcombe says.

An eye on decom

While assets are being driven beyond their design life, they will still at some point need to be decommissioned, and it is increasingly accepted this is an area which needs to be taken into consideration as part of an asset integrity program, says Andrew Duncan, who worked at the HSE on its KP4 ALE program (*OE: September 2014*). KP4 was one of four HSE programs focusing directly or indirectly on asset integrity. Duncan, now lead consultant, materials and corrosion engineering, at Intertek, says: "Over the years we have had a design team, operating team and decommissioning team as separate teams, but I would argue they need to be together to manage the life cycle better. If unmanaged, degradation continues, with [the result being] failure before the end of the life of the reservoir. Improved economics have pushed cessation of production (COP) back some years, so we have to introduce more corrosion management to allow us to at least achieve COP. COP plus five years is where we should be targeting to give us a cushion. We should also consider removing redundant equipment, simplifying processes and bringing in new fields."

Indeed, there is ongoing discussion around new tax breaks to allow industry to partly decommission facilities early, while keeping them producing. But also, if equipment is properly maintained, it can then be recycled and used elsewhere he says, a practice which the onshore chemicals industry has managed but, while discussed in the North Sea, hasn't been adopted significantly. All of which makes maintaining assets well a win-win. OE

Safety critical maintenance backlog on the UKCS

	2009	2014
Planned maintenance backlog	500*	2200
Corrective maintenance backlog	750	2700
Deferred maintenance	700	4000
Total	1950	8900

*Average man hours per installation. Data from Oil & Gas UK.

Kevin Harris, Production Chemistry Business Manager at Intertek, examining a pipeline section damaged by scale.
Photo from Intertek.

FURTHER **READING**

Read Oil & Gas UK's Health & Safety Report 2015:
http://cld.bz/V2xA61r#

Model engineering for asset integrity

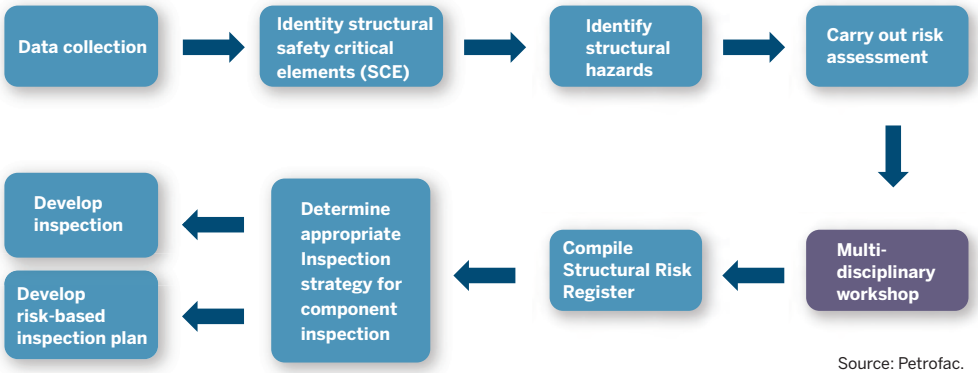
Aging assets and life extension are consuming ever more engineering hours in the offshore oil and gas industry. How can engineering tools help? Meg Chesshyre looks for answers.

Structural integrity management is a growing area of work on the UK Continental Shelf. With more than 200 installations now over 20 years old, and a number over 30 years old, there are specific challenges in terms of degradation, corrosion and fatigue, which need to be considered as facilities approach the end of their design life.

How to tackle these issues was the subject of a forum session at the Bentley Systems Year in Infrastructure 2015 conference in London this past November. A key theme was being able to reduce offshore hours through engineering by using structural integrity management and tools such as reality modeling to help build as-built models, which can be used for engineering analysis.

Proactive SIM approach

Risk based inspection planning



Source: Petrofac.

For Justin Jones, structural engineering consultant for Petrofac, the value of structural integrity management (SIM), compared to vessel rates, shouldn't be under estimated. Engineers are relatively inexpensive in comparison, Jones says. "The cost of the hire of a vessel far outweighs our engineering time to demonstrate the integrity of the structure," he says – 250 weeks of engineering costs about the same as one day of vessel hire.

The use of SIM also enables operators to have a safer structure. "If you fully understand the nature of the structure it can be safer, as well as cheaper to operate."

Jones gave five case histories of structural integrity management on a string of unnamed projects, all of which resulted in cost savings and life extension for the structures. The first was jacket push-over analysis on a southern North Sea jacket, the second loss of support material on a southern North Sea helideck, and the third, a 10,000-year wave impact assessment on an emergency shut down valve deck (something that would not have been considered at the time of design). The fourth involved fatigue analysis for life extension of a mobile offshore production unit in the Caspian Sea. The final example was of a structure with flaws in it, something that is now occurring frequently in a number of in-service assessments, especially those which have greatly exceed their design life.

It's not just the age of the assets that is increasing the requirement to get a grip on integrity. Minnie Lu, civil/structural group manager at Petrofac, says new codes and legislation are a lot more stringent than in the past and knowledge around oceanology has advanced, improving modeling. In addition: "With the depressed oil price and squeeze on capital investment in new assets, we are also facing increased pressure on extending the life of our existing assets," she said. There had also been a shift to risk-based inspection planning as opposed to fixed frequency inspection planning, she added.

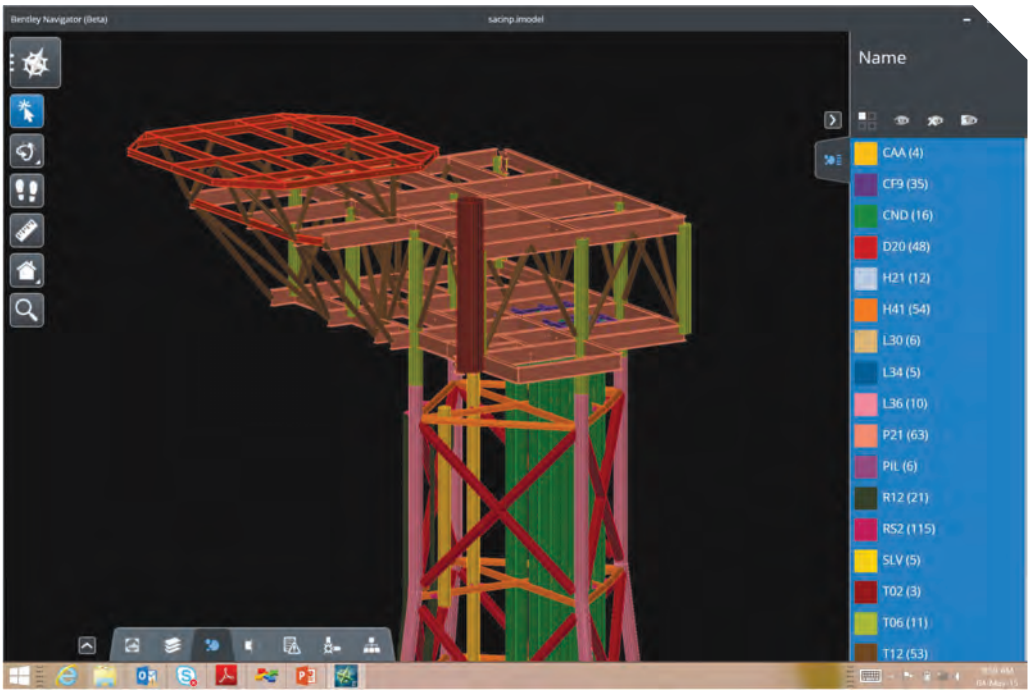
Phil Christensen, Bentley's vice president, offshore and marine, says the US Gulf of Mexico is also having to take into account a changing legislative environment, including the American Petroleum Institute's recent introduction of recommended practice 2 SIM in relation to the platforms in the Gulf of Mexico. Chris-

Inspired engineering

The winner of Bentley's 2015 Be Inspired in Offshore Engineering award at the conference was Keystone Engineering. Keystone Engineering has adapted deep water jacket-type support structure design from the oil industry for use on five, 6MW wind turbine generators on America's first offshore wind farm – the US$290 million Block Island project, which will supply power to Rhode Island and the rest of New England. Bentley anticipates that seven such structures are to be installed off the US Atlantic Seaboard by 2017.

tensen said there is quite big differences in the approach to inspection in the US and the UK. "The UK is quite far ahead of the game in terms of taking a risk-based approach. In the US it is still mostly time-based inspections," he said.

There are various reasons for this. The meteorological environments are very different. While there are constant storm loads in the winter over the North Sea, there are very isolated but very intense meteorological events in the Gulf of Mexico. When Hurricane Katrina and Irene went through the Gulf of Mexico there were 60 full platform failures. Also, "people buy and sell platforms all the time in the Gulf of Mexico, so there is less willingness to invest in something that you are going to own for five years, and then pass on."



Using Navigator i-Model viewer. Image from Petrofac.

Bentley is developing new products to meet the industry's needs in terms of structural integrity modeling. "We are adopting a 'model centric' approach to asset integrity management, he explained. "Because we have a lot of modeling applications, and our i-Model common data environment allows us to bring in models from other systems. This means we can give asset integrity planners, inspectors and engineers a model and graphical context in which to plan and carry out their inspection work as well as to run analyses as a result of the inspections."

Five of Bentley's products were listed: SACS for offshore structural and fatigue analysis, ProjectWise for engineering information management, APM for asset performance management, Navigator for information mobility, and ContextCapture for reality modeling, a new industry development as well as a new offering from Bentley, which was announced at the London conference.

ContextCapture is Bentley's first product release of the Acute3D software technology it acquired earlier in 2015. The software is ideally suited for any organization that could apply 3D models of real-world context to benefit infrastructure design, construction, or operations.

"In situations in which models are not available, tools like ContextCapture are ideal for creating models. I know drones are routinely being used for inspecting hard to get at areas like flare towers. Creating a reality mesh from the photos resulting from those inspections would be very straight forward," Christensen said. "The notion that you can now go on the platform with a mobile phone and just take photos, and actually get a really accurate, useful 3D mesh, this is really mind blowing."

But, there are also interesting business issues around where the data lives. Some owners are already all on the cloud; for others data is still on the server."I would say in five years' time it will be 80% cloud. It's an unstoppable challenge," Christensen said.

Problems being worked on at the moment include adding more ways to attach information. "I think audio attachments are going to be quite useful," Christensen said. "A lot of the time it is much easier to say the crack is outboard three feet from the end, but you have to look under the bracket to really see it. You don't really want to try and write that down." OE

Foundations for Deepwater Wind's offshore wind farm near Block Island, designed by Keystone Engineering, and built by Gulf Island Fabrication in Houma, Louisiana. This is the US's first offshore wind farm. Photos from Keystone Engineering.

Assessing caisson inspection techniques

Battling corrosion and wear offshore is a challenge faced by many operators. Elia Barnett surveys the companies tasked with inspections to find out more about today's solutions.

Corrosion and material deterioration is an ongoing challenge for subsea offshore facilities. Caisson structures used for floatation and firewater capabilities require frequent inspections in order to maintain structural integrity.

If caissons are compromised it will cripple operations on a rig, says Levi Vaverka, senior project manager for Stork Technical Services. One of the dangers of corrosion is that it will damage the structure to the point where the caisson could fall off and sink to the ocean floor. If the caisson comes off there is a huge risk of damage to the infrastructure around it, he says.

Another issue affecting caissons is holes formed due to corrosion. "If the caisson isn't holding water because it's got holes in it, then you're going to lose a lot of pressure," Vaverka says. "You're not going to get the volume you should, the pressure you should, you won't get what you should out of the fire suppression system."

A Stork inspector. Photo from Stork Technical Services.

Challenges for internal inspection

Obtaining accurate data from the caisson inspection has proven to be the biggest challenge for operators. The methods with which the data was obtained have not always been accurate.

"Technology is not designed for this type of application," Vaverka says. "The inspections that you get aren't fantastic. Some engineers were having difficulty doing their varied discrete analysis of the structural integrity of that item. And some companies have said that there's not much point doing these inspections unless we have valuable data."

There are obvious inhibitors to obtaining an accurate assessment of the caisson's condition. Access is always an issue. Many service companies report hearing from the operators that internal inspections are the most intrusive on the rig. In the case of a firewater pump system, the pump inside the caisson has to be removed in order to conduct the inspection, potentially disturbing operations. Marine gunk builds up both inside and outside the caisson. This makes the task of inspecting the caisson's condition much more difficult and allows the potential of blockages building up inside the caisson. Equipment has a potential to get stuck down hole.

Challenges for external inspection

External caisson inspection comes with its own set of challenges. While traditionally, it doesn't shut down operations, obtaining accurate data from outside the caisson is difficult. External inspections are subject to weather conditions whereas internal inspection is not. Marine matter buildup on the outside of the caisson also hinders inspection. Inspecting from the outside doesn't always catch internal degradation of the caisson, especially at the supports where there is overlapping material. Many service companies provide more than one avenue of inspection in order to obtain the most consistent data.

The methods traditionally used to inspection caissons involve simple visual inspection on both the outside and inside walls. While visual inspec-

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tion is still a valid part of the process, service companies have developed tools to address specific challenges. New technologies and techniques have been developed in order to obtain the most accurate assessment on caisson degradation. Ultrasonic corrosion testing is becoming the standard tool for internal and external inspection for many service companies. Other technologies include visual inspection, 3D laser scanning, high-pressure cleaning, and ROVs for external deepwater inspection.

A Stork worker conducting an inspection.

Stork Technical Services

Utrecht, Netherlands-headquartered Stork Technical Services, an asset integrity management specialist, uses ultrasonic corrosion mapping and 3D laser scanning for nondestructive testing (NDT) internal inspection. They also have a visual camera with bright lighting to check for any corrosion. This method is conducted simultaneously in order to make sure the data is accurate.

"The laser is a beam of light on a rotating head," Vaverka says. "As the unit goes down, the laser head is circulating. That pinpoint of laser light, when it reflects back from an object, the unit is able to see that. And it can tell based on the speed of light, how long that took, and how far something is. When you get no return, then there's a hole. If you get a return, you can calculate how deep that return goes."

Stork's tool allows for both the laser scanning and ultrasonic corrosion testing. The method uses sound waves to travel through the steel walls. Based on the return, the data analyzed reveals the thickness of the steel walls.

Sonomatic

Both Stork and Warrington, England-based Sonomatic have a tool in their arsenal, which the companies say is able to squeeze into tight places.

Sonomatic, which specializes in advanced ultrasonic inspections and asset integrity solutions introduced its new internal caisson inspection tool at the 2015 SPE Offshore Europe conference in September. Scott Bulloch, topside project manager Sonomatic, says the tool was developed because operators were experiencing problems with data quality and reliability of inspection results with existing tools currently in the market place. Limited reliability of the inspection information from existing tools can lead to less than optimal integrity decisions, with costly outcomes for operators, he says.

Also tools becoming stuck within the structures were an issue, "This was having major impacts on operations offshore," Bulloch says. "Our tool has several fail-safe mechanisms in it. With any loss of power, the whole tool collapses and we can retrieve it, we have other mechanisms that prevent it from getting jammed from unexpected obstructions, thereby lowering risk of downtime to the asset."

Sonomatic's tool can inspect both the dry section and submerged section with ultrasonic corrosion mapping to complete the internal inspection for remaining wall thickness, and can inspect welds from the corroded surface looking for fatigue cracking. The company also deploys subsea tools deployed by ROV for external inspections with various ultrasonic imaging techniques.

Innospection

Aberdeen, Scotland-based Innospection specializes in electromagnetic inspection technologies for its NDT solutions, specifically the Magnetic Eddy Current (MEC) technique.

Standard Eddy Current is only sensitive at the surface of the metallic material. "Modification to the standard Eddy current enables the deeper inspection of the metallic structures," says Andreas Boenisch, managing director at Innospection. "Defect detection using the MEC technique is achieved by superimposing direct current magnetization with an Eddy current field i.e. an Eddy Current coil is used on the ferromagnetic material while the section of the ferritic steel component is magnetized at the same time." With this technique, internal defects such as corrosion, pitting and cracks can be detected from the external surface.

The MEC technique can be used on caissons with an outer diameter of 10-42in, wall thickness up to 25.4mm and coating thickness up to 15mm, Boenisch says. This method requires only the removal of heavy marine growth prior to the inspection and can also be used in conjunction with other advanced inspection techniques such as ultrasonic testing.

AISUS Offshore

AISUS Offshore, also based in Aberdeen, specializes in remotely deployed visual and ultrasonic inspections. For the company, the high-pressure cleaning goes hand in hand with the ultrasonic inspection method because the data obtained from the ultrasonic is more accurate when the marine debris is removed.

"We use a zone 2 diesel driven high-pressured water jetting unit to remove all scale, marine growth and loose debris from the caisson interior," says Stuart Lawson, managing director, AISUS Offshore. "The cleaning apparatus can operate at pressures between 6000-10,000 psi."

The visual inspection method uses a remotely deployed camera that scans the internal walls. The camera is backed up with LED lights and lasers that looks for degradation, blockages, internal diameter changes, wall loss defects, corrosion, scale and any other anomalies identified during the inspection.

Conclusion

Caisson inspections are important for maintaining the integrity and safety of the rig. The inspection process has always posed a challenge because of hard to reach places that limit or hinder obtaining accurate data. The industry has developed many techniques to address these challenges both for internal and external topside and subsea inspection from visual inspection, 3D laser scanning, ultrasonic corrosion scanning, and electromagnetic currents. Often running one or more of these techniques increases the accuracy of the data obtained. As technology improves in these fields, so does the quality of data, and the ability to make decisions on how best to improve the life of offshore assets. OE

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Wear and tear

Audrey Leon spoke with DNV GL's Michiel van der Geest about its new joint industry project regarding wear acceptance criteria for jacking systems. Currently 13 companies have signed on to the project, which aims to provide criteria for better assessing self-elevating units.

In late November, DNV GL announced it would begin a new joint industry project (JIP) on the heels of its last project to provide recommended practices for jacking system maintenance and inspectionsl; the JIP occurred from 2013-2014. Guidelines were published in September 2014. The new JIP aims to simplify further an area that is already complex.

"Defining maximum limits of wear across all parts of a jacking system is technically complex," says Michiel van der Geest, product manager offshore classification, DNV GL - Maritime. "It not only involves the interaction of all elements of the system, including the different materials applied, but also relevant operational and maintenance strategy considerations," he said at the time the JIP was announced. ***OE*** spoke with him to learn more about the new JIP and what to expect.

van der Geest

OE: How did the new JIP come about?

This recent JIP has a history in a successful joint industry project we executed in 2013-2014 resulting in a recommended practice on Jacking System Maintenance and Inspection (ref DNVGL-RP-0075). The project group realized that, even though we met our project aim, we needed to stay proactive and try to bring the jackup industry forward. As such, we have developed a series of workshops/conferences in further explaining the recommendations.

In one of these workshops, in Houston in September 2015, an issue was raised on acceptable wear limits and the unclear situation around these. This lack of clarity gives way to unnecessary discussions, time loss and cost for follow up analyses.

Photo from iStock.

After a constructive discussion during the workshop (attended by main rig owners as Paragon, Rowan, Seadrill and Noble, but also an original equipment manufacturer (OEM) as Friede & Goldman) we took the idea further and decided to propose a JIP.

OE: Who is involved in the JIP?

At this moment, we have confirmed engagement from drilling contractors, such as: Noble Drilling, Rowan, Paragon, National Drilling Co., Shelf Drilling (supported by Aggreko), and UMW. OEM designers: GustoMSC, Friede and Goldman, NOV-BLM and Siemens AG. And service suppliers: AllRig (in partnership with Ali & Sons), David Brown and Zentech. In all 13.

OE: What will the JIP evaluate and what does DNV GL hope to accomplish?

The project will evaluate all relevant elements of the load path, from the spud-can through the legs, jack gear and rack chock to the jacking house with a focus on wear and the related effects on load and wear of other components of the jacking system.

In addition, we'll have an operational view in considering relations to maintenance strategy and (acceptable) operational limitations.

At the end, we and our project partners' aim for documenting the relevant design arguments, considerations and calculations to define wear acceptance criteria. Ideally, we produce a process flow with an overview of all relevant arguments which can be used by all industry partners to define the acceptable wear for a unit on a case-by-case basis.

OE: What is your approach to the project?

The first step is to collect relevant technical considerations relevant for the determination of maximum allowable wear limits; this includes, but are not limited to topics such as, listing of (typical) geometry and material of racks and pinions, different pattern of wear and tear, allowable contact stresses and failure analysis, wear and related effects on other components.

The second step is to describe the trade-offs to be made in accepting wear level vs. effects on asset to higher wear rates, operational limitations and availability.

The third step aims to define guidelines and approaches to define acceptance criteria given a set of operational choices and constraints. The result of this approach should be a process description making it clear how one should define acceptance criteria for a specific unit, for specific operational considerations.

OE: What other benefits are there for including the jacking system in a predictive maintenance campaign?

This must be in further reducing maintenance cost. Being able to assess the conditions of the system and knowing the remaining wear margins gives the possibility to further focus and plan the maintenance activities and reduce downtime/maintenance periods even more. **OE**

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VISION, EXPERIENCE, ANSWERS FOR INDUSTRY

Asset integrity from the start

Greg Hale takes a look at how Shell integrated an asset integrity program into its new Prelude FLNG project with the intent of saving millions over the next 20-25 years.

Thinking ahead and integrating an asset integrity program from the beginning will save Shell millions of dollars with its Prelude Floating liquefied natural gas (FLNG) project over the next 20-25 years.

"Shell has been thinking about it from the beginning," said Scott Hokeness, business development manager at Emerson Process Management. "They realized they will have a limited staff on the ship. From the start, they knew they would be monitoring assets from onshore and supporting a skeleton team on the ship with information on what repairs are needed and what the priorities are. They had this in mind from the start, so as they are configuring their smart devices, they are very careful to set up their alerts from the get go, so when the ship goes on station, they will be ready to monitor it from shore."

With the industry in a tailspin and profits running tight these days, operators need to squeeze and pull as much out of systems and that is where asset integrity shines.

Definitions of asset integrity abound, but essentially it is the ability of an asset to perform its required function effectively and efficiently while protecting health, safety and the environment when required over the entire lifecycle of the asset.

"The most common view of asset integrity is getting good values from the device as it is working with control strategies and process monitoring," Hokeness said.

What makes the Shell project interesting from an asset integrity point of view is the oil and gas giant is incorporating it in from the beginning and not just bolting it on.

"More and more we see (users) from the start designing the projects to take advantage of smart instrumentation and the diagnostics that come with them," Hokeness said. "Shell has taken the strongest stance I have seen where they have designed their maintenance exclusively around the smart instrumentation and the diagnostics that come with them. Traditionally many plants will run to failure and then schedule maintenance."

"Without a doubt, if you can fix (equipment) before it fails you don't incur the cost of downtime for the process. If you can schedule work during turnarounds or scheduled downtime, that is far more cost effective than having to shut the process down to repair it," Hokeness said.

Prelude to a floating plant

Once it is up and running, the Prelude

Integrating an asset integrity program from the beginning will save Shell millions of dollars with its Prelude Floating liquefied natural gas vessel which is now undergoing commissioning.
Photos from Shell.

FLNG facility will produce at least 5.3 MTPA of liquids: 3.6 MTPA of LNG, 1.3 MTPA of condensate (equivalent to 35,000 b/d) and 0.4 MTPA of liquefied petroleum gas (LPG).

The floating facility will chill natural gas produced at the field to -162°C (-260°F), shrinking its volume by 600 times so it can ship out to customers in other parts of the world.

Ocean-going carriers will load the LNG as well as other liquid by-products (condensate and LPG) for delivery to market.

The Prelude FLNG facility will be 488m (1600ft) long, 74m (240ft) wide and along with its contents, will weigh around 600,000-tonne. It will be the largest floating offshore facility in the world.

Once construction is completed sometime next year, Shell will tow the facility to its location, around 300mi northeast of Broome, Western Australia.

The facility will then end up moored and connected to the undersea infrastructure and the whole production system will be commissioned.

It will remain permanently moored at the location for between 20-25 years before needing to dock for inspection and overhaul.

Technologies Shell will use on the FLNG facility are ones used successfully onshore, but the company had to adapt or modify some of them in order for the processes, such as liquefaction and offloading, to run at sea.

"This has never been done before," said Neil Gilmour, Shell vice president Integrated Gas Development in a published report. "We had to find ways to adapt our technology for offshore."

"From a smart device perspective, they will be able to monitor the health of all of their Foundation fieldbus and HART devices," Hokeness said. "They have primarily been using fieldbus for their basic control and HART for their safety systems."

Shell's FLNG also allows for:

- High production rates of up to 6 MTPA of liquids (including LNG, LPG and condensate)
- A wide range of gas compositions and can export LPG and condensate
- An efficient double mixed refrigerant liquefaction cycle
- The ability to stay on station and not have to be moved during severe weather conditions such as cyclones, which will increase the availability of the plant

New approach

Moving toward an asset integrity program, Shell had to think about making some changes and not remaining with the status quo. That started with using smart technology.

"They changed their work practices during the commissioning part of the project," Hokeness said. "They are using the intelligence from their devices right away. When they were commissioning their valves they turned the alerts to make sure they had sufficient air pressure and the valves move the way they are supposed to.

"They do that all upfront and that is a change from the past where they wouldn't necessarily look at the device until they went online with the project," he continued. "They are seeing some tremendous savings using the bulk commissioning tools we collaborated on and implemented in the AMS Device Manager software. If they had 100 pressure transmitters configured the same, we are now able to push the configuration to them, push the alarm set up to them and do it all in one go. This new functionality has produced phenomenal savings. It makes sure the smart devices are consistently configured and the right alerts are turned on."

Shell also worked with the engineering contractors (EPCs) to get them on the same page.

"They told me they worked with their EPCs to change their work practices to use the new tools. That was a step away from how it used to be done. The contractor usually does it their own way, but Shell worked hand in hand with them on the new strategies."

While the industry is down now, it will eventually come back, but will asset integrity remain a focal point for users or will it fade away as profits start to rise?

"Even when the market does come back, people will continue to care. We have seen increased focus on asset integrity even before the oil and gas market has gone down," Hokeness said. "It may be more appreciated now because there are fewer capital projects. There is more focus on reliability and getting the most out of what you have." OE

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

Middle East

Middle Eastern resilience

Both maintaining and launching new offshore production is high on the agenda in the Middle East, not least in Saudi Arabia, the UAE and Iran. IHS' Mirzi Moralde outlines current activity in the region.

Offshore construction activities in the shallow water Middle East Gulf region continue to show signs of resiliency, since the price of crude oil dropped by more than 50% in June 2014.

Several engineering, procurement, construction, installation and commissioning (EPCIC) contracts have been awarded by major operators like Saudi Aramco, Abu Dhabi Marine Operating Co. (ADMA-OPCO), Zakum Development Co. (ZADCO) and Qatar Petroleum (QP) this year alone. A number of field development projects will also be brought to tender in 2016, aimed at sustaining and increasing production capacity in line with OPEC's decision to maintain market share in the current low oil price environment.

Iran in the Persian Gulf will also add to OPEC's production capacity, once sanctions are fully lifted. These recently awarded projects and those that will be tendered for in the coming years will provide an added boost to current and ongoing offshore work towards the end of this decade.

Total's Abu Al Bukhoosh (ABK) field offshore Abu Dhabi, UAE.
Photo from Total

Saudi Arabia

In Saudi Arabia, Saudi Aramco, which has a maximum production capacity of 12 MMb/d, has moved forward with its Maintain Potential Programme (MPP), covering brownfield work on producing fields, after it awarded to McDermott a lump-sum engineering, procurement, construction and

installation (EPCI) contract with an estimated value of around US$1.5 billion to $1.8 billion. The project covers several platforms and pipelines.

In addition to McDermott, Saudi Aramco has also pre-qualified three other EPCI contractors, which will bid for three long-term agreement (LTA) tenders under the MPP. The list includes partners Larsen & Toubro (L&T) and EMAS, Dynamic Industries from the US and Saipem. This pre-qualification process will allow these four contractors to enter into commercial bids for LTA tender packages under unit rate basis for a period of six years with an option to extend for the next three years.

Wood Group will also carry out a firm six-year contract with options for greenfield and brownfield engineering services, procurement and construction management support for new facilities under the MPP. Wood Group Mustang in the US and its Saudi Arabia-based joint venture Mustang-HDP, which has been providing services to Saudi Aramco since 2011, L&T under a general engineering services contract, will carry out the scope.

Additional infrastructure on Saudi Aramco's first offshore non-associated gas field, Karan, is underway, following the EPCIC contract award to Saipem in October. The package covers an observation platform, a wellhead production deck module, auxiliary platforms, a 20in internally clad flowline and composite power cable. The Karan field started production in 2012.

In December or by early 2016, the Wasit gas development program, composed of non-associated gas fields, Arabiyah and Hasbah, is set to commence production. It is targeted to produce around 2.5 Bcf/d of gas, once fully operational. The EPCIC contract, which covers platforms and pipelines on both fields, was awarded to Saipem in 2011.

Saudi Aramco will also further expand the Hasbah gas facilities with bids ongoing for the EPCIC tender package, involving six wellhead topsides, two tie-in platforms, flare tripods, bridges, pipelines and umbilicals. Saudi Aramco has pre-qualified four contractors, which includes L&T in partnership with EMAS, McDermott, Saipem and Dynamic Industries. Contract award is anticipated in Q1 2016.

Meantime, deepwater exploration drilling activities in Saudi waters of the Red Sea area are at a standstill after being put on hold since March, due to high operational costs in the current downturn. However, a jackup drilling rig is expected to continue working in the shallower parts of the Red Sea until 2018. Saudi Aramco has so far discovered the Al Shaur 1 (Al Shoor 1) well in 107m water depth in 2012 and the Al-Haryd oil field in 2014.

Abu Dhabi

Abu Dhabi in the UAE is aiming to increase production capacity from around 2.8 MMb/d to 3.5 MMb/d. ZADCO and ADMA-OPCO are taking the lead in offshore field development programs aimed at achieving this goal.

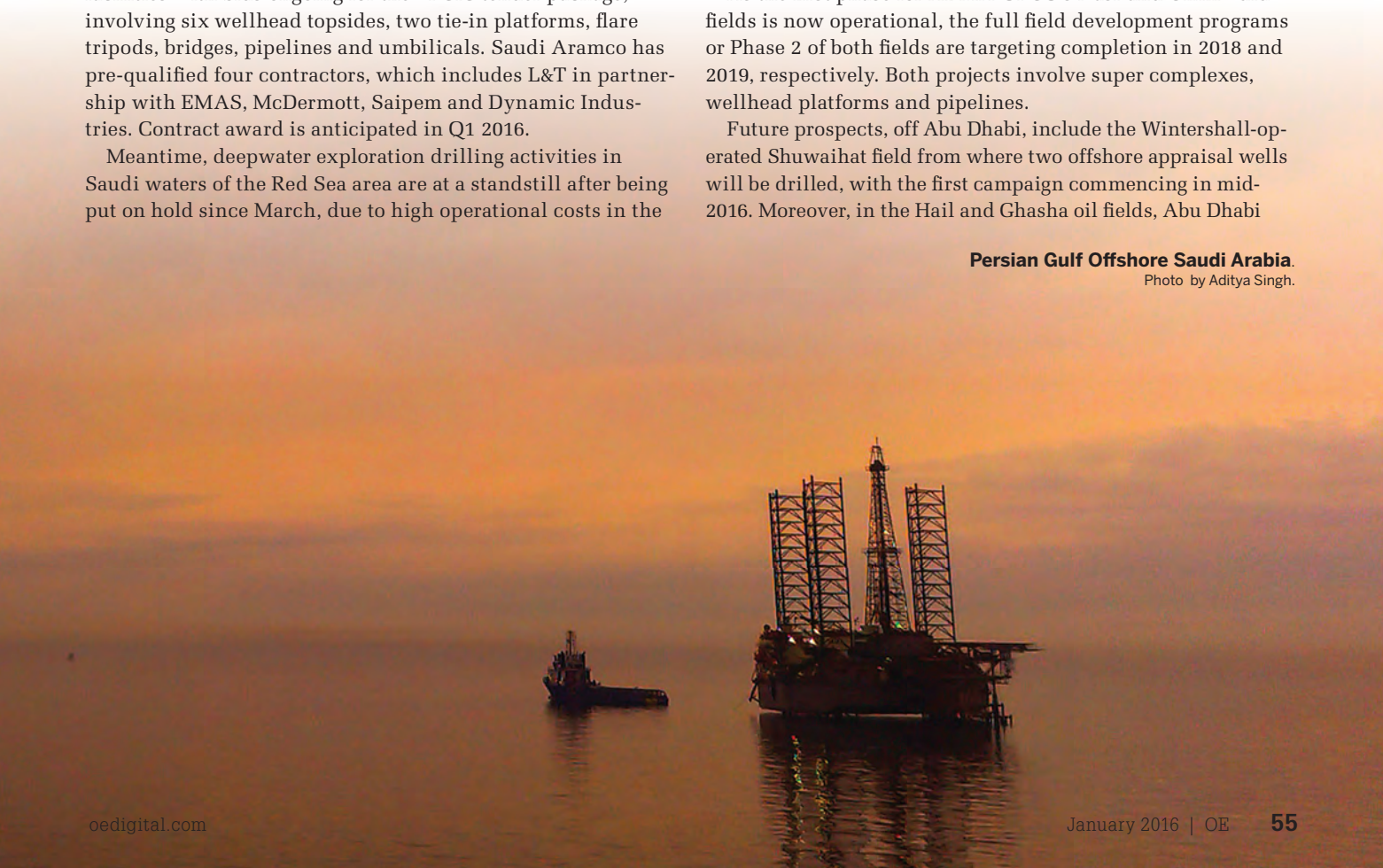
ZADCO is anticipated to release a tender package for around six wellhead platforms and six to eight pipelines for the North West Development Project, in around 9m water depth in the Dalma field, in 2016. Other infrastructure like the drilling platform for 12 wells will likely be awarded to NPCC under a negotiated contract by early 2016. ZADCO will prioritise gas production on the Dalma oil and gas field, which was discovered in 1971.

Meantime, construction work on the ZADCO-operated UZ 750 in the Upper Zakum field, off Abu Dhabi, is set to conclude in 2016. Oil production is expected to increase from 500,000 b/d to 750,000 b/d upon completion. A variation order on the contract, awarded to NPCC, will further enhance production capacity on this field by 100,000 b/d.

Several ADMA-OPCO-operated projects were also awarded in the first half of the year. The $855 million EPIC Lower Zakum Pipeline Replacement programme that went to NPCC involves around 25 oil pipelines plus topside modification work while the $200 million EPIC Zakum facilities project was awarded to McDermott. Both campaigns are set for completion in 2017.

As the first phase for ADMA-OPCO's Nasr and Umm Lulu fields is now operational, the full field development programs or Phase 2 of both fields are targeting completion in 2018 and 2019, respectively. Both projects involve super complexes, wellhead platforms and pipelines.

Future prospects, off Abu Dhabi, include the Wintershall-operated Shuwaihat field from where two offshore appraisal wells will be drilled, with the first campaign commencing in mid-2016. Moreover, in the Hail and Ghasha oil fields, Abu Dhabi



Persian Gulf Offshore Saudi Arabia.
Photo by Aditya Singh.

Middle East

The ABK field, offshore Abu Dhabi. Photo from Total.

National Oil Company (ADNOC) and Occidental Petroleum Corporation (Oxy) will carry out 3D seismic surveys, drilling of appraisal wells and engineering studies by 2017. The activity is covered in the $500 million technical evaluation agreement (TEA) signed between ADNOC and Oxy in February 2015.

Qatar

Several contracts were awarded offshore Qatar in Q4. The RasGas EPCI package for the flow assurance and looping project that covers around 119 km of 6-8in pipelines as well as topside modification contract went to McDermott. The scope is expected to be concluded in Q3 2017. QP also awarded McDermott the EPCI contract for brownfield work on the Bul Hanine field. The campaign will cover four wellhead jackets, with the first two set to be installed by December 2016, while the remaining two will be installed in July 2017.

Meanwhile, bids for the QatarGas Operating Co.'s EPCIC tender for a living quarters (LQ) platform on the North Field Bravo (NFB) are underway. The LQ platform will have the capacity to accommodate around 90 persons. The scope will also include modification of existing LQ facilities and brownfield tie-ins to the process and utility platforms. The NFB is in about 52m water depth.

However, development on the Al Radeef gas field, in Block 4, near the North Field, remains at a standstill after Wintershall returned the block to Qatar in May 2015. Wintershall discovered the Al Radeef field in 2013.

Bahrain

BAPCO is in the process of evaluating its offshore blocks for the new licensing and bid round, anticipated to open in 2016. BAPCO's evaluation will be based on previous campaigns carried out by Thailand's PTTEP and Oxy. PTTEP relinquished Block 2 in 2012 while Oxy also relinquished Blocks 1, 3 and 4.

Oman

Over in Oman, plans for deepwater exploration activities in Block 41 have yet to progress after Total relinquished the block in 1H 2015. Total had signed an Exploration and Production Sharing Agreement (EPSA) with the government of Oman in 2013. The EPSA covers 23,580sq km of the block in 30-3000m water depth. Total pulled out of Block 41 after conducting studies on seabed cores and samples.

Iran

Prospects of multi-billion dollar projects offshore Iran have been generating a lot of interest from both international oil and gas companies as well as international and Middle East-based offshore EPIC and service contractors since last year. These development programs are anticipated to move forward in 2016, once the Iran Petroleum Contract (IPC) is in place, when sanctions are fully lifted. Iran is targeting to reach around 4.7 MMb/d of production capacity in the years ahead.

Other than the current and ongoing development campaigns on the South Pars field, major prospects like the North Pars, Golshan, and Ferdowsi gas fields have yet to be developed. Plans have been drafted since 2007, for the Ferdowsi and Golshan gas fields. The Ferdowsi master development plan, estimated to be around $2 billion, will cover the drilling of 13 initial producing wells, one gas production platform, one 26in pipeline and an onshore processing plant plus support facilities.

The Ferdowsi field is estimated to be capable of producing around 500 MMcf/d of gas. A major oil layer beneath the Ferdowsi gas field had also been discovered with an estimated in-place reserve capacity of around 34 billion bbl. On the other hand, the Golshan gas field is planned to have around two platforms and two 26in pipelines that will connect to an onshore processing plant. This field is targeted to produce around 2 Bcf of gas, once fully operational. The estimated cost for this development is around $6 billion. Over in the North Pars gas field, final studies of development phases are underway. The North Pars sits in around 2-30m water depth. It is estimated to hold around 58.9 Tcf of sour gas.

Going forward, more offshore construction work is anticipated, once Iran commences development of its new and major oil and gas fields. In the meantime, Saudi Arabia, Abu Dhabi in the UAE and Qatar will continue to lead the Middle East Gulf region in maintenance of existing fields and the expansion of producing assets as well as developing greenfields for production. **OE**

Mirzi Moralde is a senior specialist at IHS based in Dubai. Moralde covers the Middle East Gulf offshore oil and gas construction market, focusing on field development activities from discovery, engineering, procurement, construction, installation and production phases. Moralde joined ODS-Petrodata in 2008, which was acquired by IHS in 2011, and has 10-years' journalism experience in the Philippines and Dubai and a degree in Mass Communication, major in Broadcast from the University of the Philippines.

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Middle East

Digital gains Middle Eastern ground

As easy oil depletes all over the world, Middle Eastern producers are turning to digital oilfield technology to not only enhance recovery but make finds economical to produce. Heather Saucier investigates the region's technological gains.

Visualization of a digital oilfield developed by Petrolink. Photos from Petrolink.

As luck would have it, many countries in the Middle East have enjoyed simple oil far longer than other areas of the world – making the need for high-tech digital oilfields (DOFs) more of a luxury than a necessity. But, many fields that have abundantly produced for decades have reached their peaks. This has prompted Middle Eastern countries to adopt DOF technology not only to enhance onshore oil recovery, but to economically produce from new offshore areas.

In fact, Middle Eastern countries are diving into DOF technology – so much so that the Middle East is expected to be the fastest growing market in DOF technology for at least the next six years, according to RnR Market Research, which provides reports from leading global publishers and in-depth market research studies.

The coming years could see one of the most prolific times of hydrocarbon production offshore for the Middle East, according to reports from the Middle East Economic Digest (MEED). "Deep sea production offers more challenges and is more difficult to execute," MEED reports. "But there will be no shortage of companies wanting to be involved."

When many Middle Eastern countries have drilled wells, oil has often flowed from the ground as water down a river. As such, some in the industry say they have not been pushed to develop new technology for sustaining or boosting production.

While the Middle East as a whole might be late to the DOF technology party, some Middle Eastern countries that are currently operating high-tech DOFs are leading the industry when it comes to data management, says David Johnson, vice president of Research and Innovation of Petrolink Services, Inc., a global leader in oilfield operations data management and delivery.

Rather than relying on proprietary solutions, some Middle Eastern oil companies are sharing data among all companies that work on their wells. As a result, they are breaking down silos and becoming a fast prototype for optimizing information management in a DOF world, Johnson says.

DOF boom

As oilfield operations become increasingly complex, especially in offshore areas, investments in DOF technology continue to grow. In terms of revenue, the DOF global market is expected to reach US$33 billion by 2022 – its compound annual growth rate (CAGR) increasing by 4.8%, according to RnR. While Western Europe and North America continue to dominate the market, the Middle East is expected to outpace all five world markets with a CAGR of 5.9%.

"It may be the world's richest hydrocarbon habitat, but as the development of new fields and maintaining or expanding output levels at existing ones is becoming more complex, the region's national oil companies (NOCs) have begun adopting the DOF concept…," wrote James McCallum, the CEO of LR Senergy, a Houston-based energy services company, in a November 2015 op-ed piece in the Arab News. "From

Abu Dhabi to Kuwait, from Oman to Saudi Arabia, regional NOCs have started to embrace the concept and are now actively engaged in implementing numerous DOF projects."

Major fields, such as Saudi Arabia's Ghawar oilfield, are on the decline, forcing countries to adopt DOF technologies that maximize oil recovery in onshore reservoirs, as well as facilitate higher productivity, lower costs, and reduced exposure to health, safety and environmental risks in offshore locations.

"While many Middle Eastern countries have offshore acreage that has been in production in the Persian Gulf, more offshore operations are to be expected," says Julian Pickering, CEO of Geologix Systems Integration Ltd., based in the United Kingdom.

While Saudi Arabia has been the largest offshore oil producer in the Gulf, Iran, Qatar and the United Arab Emirates (UAE) are the major offshore producers of gas. However, because many of the Gulf's hydrocarbons have already been discovered or are currently being exploited, oil companies will be casting their eyes on the undeveloped reserves in non-associated gas fields in the Gulf and on untapped oil and gas reserves in the Mediterranean and Red seas, according to MEED.

Petrolink's team in Saudi Arabia giving a geosteering demonstration in its Saudia Arabia-based RTOC (real-time operations center).

Technology needed

To do this, countries will have to invest in strong DOF communication infrastructure so that offshore platforms can communicate with the onshore environments, Pickering says.

Such technology might include fiber optic cables or maritime wireless networking, which is replacing conventional satellite communications with higher bandwidth and high-speed communications. Wireless communications can facilitate remote monitoring and control during production, and allow for troubleshooting at earlier stages while maintaining a consistent flow of product.

What's more, building DOFs from scratch today has its advantages.

"Because of their later entrance into the advanced technology market, most Middle Eastern companies are committing to good technology and making sure they have solid plans and operations procedures," Pickering says. "They are learning from other areas that have been more exploratory. They are building real-time operating centers and centralizing operations and providing areas where subsurface teams can work with drilling teams and so on."

DOFs are highly instrumental in offshore reservoirs, as they allow control of a well from remote locations. Through instrumentation and automation as well as IT services, they are commonly known to improve reservoir, production and drilling optimization, safety management and the ability to maintain and repair equipment.

Furthermore, DOFs enhance collaboration, support decision-making, integrate big data and automate workflows – both horizontally in operations and engineering, and vertically within the company, inclusive of as many disciplines as possible.

DOFs also are seen as lifesavers as the industry loses thousands of experienced workers to attrition, Pickering says. They require fewer workers to be stationed on platforms, enabling them to transition to onshore control centers and manage operations in smaller teams.

"Digital oilfields have got a big role to play in the current climate in oil and gas," Pickering says. "More than 250,000 people from the industry retired in 2015. That's a heavy loss of expertise. In addition, a lot of equipment has been decommissioned and it will not be easily available in the future. Digital oilfields are about making people work more efficiently and smarter."

Setting precedents

The Middle East may not be as "cutting edge" as the rest of the world when it comes to DOF technology, but it is at the forefront of operating DOFs with open standards for data transfer and communication, Johnson says.

"In developing digital oilfields in North America, we started with developing the best technology and we came up with amazing software, like 3D seismic, geosteering and real-time monitoring," he says. "In the Middle East, they are starting with data management and integrating their teams, which is essential to boosting output. Silos still exist in North America, but they are coming down in the Middle East."

Tired of "translating" the data it received from a multitude of service companies into one consistent format, Saudi Arabia adopted WITSML (Wellsite Information Transfer Standard Markup Language), an industry initiative based on XML (Extensible Markup Language) technology to provide open, non-proprietary standard interfaces for technology and software that monitor and manage wells, completions and workovers, says Jay Hollingsworth, chief technology officer for Energistics, a nonprofit membership organization that manages WITSML.

The first to adopt this practice, Saudi Arabia's leadership has encouraged other countries, such as Kuwait and the UAE, to consider doing the same, Hollingsworth says.

"The Middle East has a unique view of the world in which everybody working for them is a part of their service provider infrastructure," Johnson explains. "Countries are beginning to manage their data infrastructure in a way that makes it completely open to all parties working on those countries' wells. But the information is secure and the technology works for everybody. It provides a neutral and natural way for competitors to do what they were hired to do without having to worry about their competitors."

Prolific in oil with access to world-class DOF technology, the Middle East will continue to be a frontrunner in oil production, speculates Johnson, and a trendsetter of data management in this world of big data that continues to grow. OE

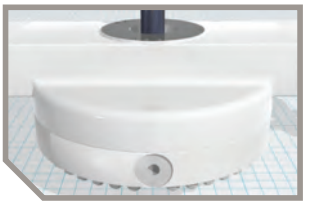
Solutions

Proserv introduces first Gilmore SIL valve

Proserv has introduced the first of four distinct Gilmore SIL pilot operated valves for use in safety integrated functions, as part of a Safety Instrumented System (SIS). The Quick Exhaust Valve (QEV), 3-way 2-position pilot operated valve, was specifically designed and delivered for use in a major operator's high integrity protection system (HIPPS). The HIPP system allows a high pressure production system to safely connect to current pipeline infrastructure. The QEV is a SIL 2 suitable valve certified suitable for a SIL 3 in a redundant configuration within the HIPPS system. The QEV valve is constructed of highly corrosive resistant materials and it is capable of high flow rates and 1000 on demand cycles. Its soft seat valve design has more than 35 years of history in subsea installations throughout the world. The valve is approved for 30 years' use subsea without maintenance.

www.proserv.com

BOP Technologies launches fail-safe design



Houston-based BOP Technologies announced a new approach to allow a BOP to work even if the drilling rig loses power or hydraulic pressure. BOP Technologies' design places a backup system in the body of the BOP Shear Ram mechanism itself. If power or hydraulic pressure is lost, there would still be a way to safely cut and close-off the well, protecting the crew and preventing oil from being released into the environment. BOP Technologies released the Circular Intensified Ram Blowout Preventer (CIRBOP), a new type of BOP that can deliver 5 million lbs. of shear force to the rams, which the company says is twice what existing BOPs can deliver and more than enough to cut any pipe, tool joint, collar or other component that may be in the drill string.

www.boptechnologies.com

WFS Technologies extends battery life

WFS Technologies has developed a battery management system technology that enables the battery life of subsea wireless instrumentation and control systems to be extended to up to 15 years. Seatooth Endure technology integrates this battery management technology with wireless data connectivity to deliver sensor, monitoring and control systems which have an extended operating life, facilitating deployment in relatively inaccessible or sealed environments.

The use of WFS Technologies Seatooth products as an alternative to hard-wired systems delivers potential cost savings in production optimization, asset life extension, and inspection, repair and maintenance (IRM) projects.

www.wfs-tech.com

Weatherford lands 1180-ton casing string

Weatherford achieved a new world record by landing an 1180-ton (2.3 million lb) casing string at a total depth of 26,805ft (8170m). The job was performed on a deepwater rig in the Gulf of Mexico this fall.

The operator of a deepwater rig in the Green Canyon required installation of a heavy, 14in, 112.6 lb/ft casing string. The total weight of the casing and landing string needed to reach total depth was 1180 tons. The operator contracted with Weatherford to install the landing-string slips 1250 (LSS 1250), which acts as a spider to safely and efficiently grip tubulars and has a maximum load capacity of 1250-ton (2.5 million lb).

Weatherford deployed the LSS 1250 after providing an engineering analysis to verify that the pipe could reach total depth without damaging the tubulars from excess stress. The team then ran the string to total depth with no issues. Without the increased load capacity provided by the LSS 1250, the operator would have needed to drill a second hole section and run two separate casing strings at an approximate cost of US$15 million. **www.weatherford.com**

OTC, Hecate launch digital pressure testing software

Offshore Technical Compliance (OTC) in partnership with Hecate Software has introcued Greenlight, a digital pressure testing software suite that provides reliable pressure analysis and compliance oversight.

Greenlight uses proprietary algorithms to conduct, analyze and document a wide variety of pressure tests, and does not require benchmark testing for a baseline reading. The software's interface allows for onsite annotations and test associations, analysis and reporting. All test results can be reviewed by OTC's team of petroleum engineers and compliance professionals to ensure regulatory compliance and documentation accuracy.

www.otcompliance.com

Offshore sector to be highlighted at AOG 2016

The 35th Australasian Oil & Gas Exhibition and Conference (AOG) will pay special attention to the offshore sector when it returns to Perth in February 2016. With a string of world class Australian LNG projects making the transition from the construction to operational phase on both sides of the country, offshore support and work boat activity will feature highly at AOG 2016.

For the first time in the event's lengthy history, work boats will feature in a specialist zone, with strong content support being provided by Royal Institution of Naval Architects (RINA), Maritime Industry Australia (MIA), the Australian Shipbuilding & Repair Group (ASRG) and the International WorkBoat Show.

With fixed and floating offshore structures, Prelude FLNG, and maritime Solutions for offshore oil and gas providing significant content for the AOG 2016 conference program.

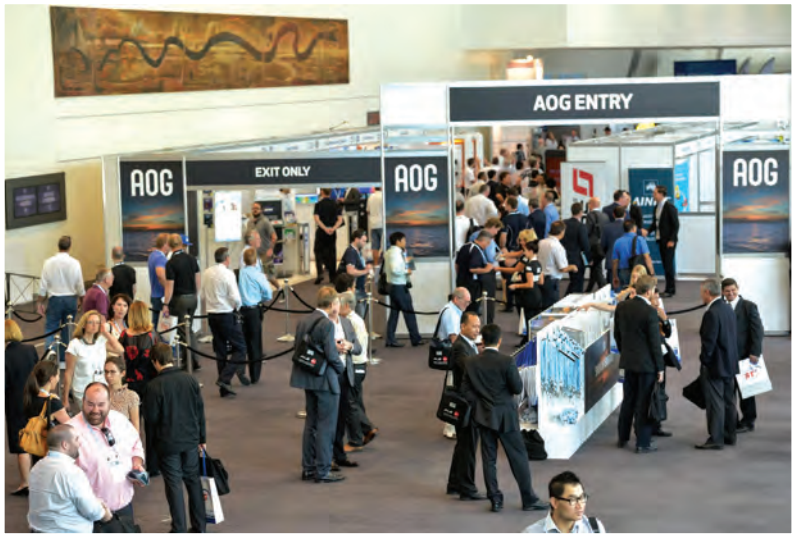
Subsea will also be a major focus with a world class Subsea Zone featured in the exhibition pavilion.

AOG Event Director Bill Hare said that industry feedback has played an important role in determining the content and scheduling for the AOG 2016 Conference.

"There is no doubt that the service and supply sector is going through tough times at the moment thanks to continuing low crude oil prices. However, we believe that well credentialed events such as AOG – which features up-to-date and informative content – will provide significant benefit for those that attend," Hare said.

AOG is once again receiving strong content support from local and international subsea bodies such as the Society for Underwater Technology (SUT), Subsea Energy Australia (SEA)

The 2016 event will include significant international participation with a range of major international pavilions including Norway, China, Singapore, the USA and the UK – with AOG once again playing a critical role in the transfer of knowledge between the northern and southern hemispheres. For more information, please visit: **aogexpo.com.au**. ▪



Fluor to acquire Stork

Engineering and construction services firm Fluor has signed an agreement with UK-based private equity firm Arle Capital Partners to acquire 100% of Stork Technical Services, in a deal worth approximately US$755 million (€695 million). Stork is a global provider of maintenance, modification and asset integrity services. Once the acquisition is completed, Fluor will begin combining its operations and maintenance organization with Stork. Current Stork CEO Arnold Steenbakker will lead the combined group and report directly to Fluor's CEO David Seaton. The management team will be formed by Stork's existing management combined with the managers of Fluor's operations and maintenance business. The combined group, branded Stork and headquartered in the Netherlands, will have an annual turnover of approximately $2.3 billion (€2.1 billion) and a total of approximately 19,000 employees.

Schlumberger-Cameron merger wins approvals

Cameron stockholders voted to approve the merger agreement between the equipment manufacturer and Schlumberger in mid-December at a special meeting. The news comes one month after the US Department of Justice cleared a legal path for the merger, granting early termination of the waiting period required by the Hart-Scott-Rodino Antitrust Improvements Act of 1976. The transaction remains subject to regulatory approvals and customary closing conditions. Both companies expect the acquisition to close in Q1 2016. In late August, oilfield services giant Schlumberger announced it would acquire Cameron in a deal worth US$14.8 billion. ▪

Westcon Yard expands production capabilities

Unison has installed and commissioned a second all-electric pipe bending machine at Westcon Yard, a Norwegian offshore and maritime services company. Capable of generating 660,000 Nm of continuous, servo-controlled torque, the machine will bend carbon steel pipes up to 10in (273 mm) in diameter.

Westcon intends to produce virtually all the pipe sizes it requires for its outfitting, service and repair operations entirely in-house, eliminating the need to buy-in preformed bend parts for these pipe sizes, and reducing the number of cutting, welding and testing operations needed for each assembly.

"Now that the larger bending machine is in place, we expect to substantially reduce production times for all pipe sizes," says Tommy Nilsen, head of prefabrication at Westcon's Ølensvåg facility.

Spotlight

Differentiating through technology

Aging infrastructure, deep waters, high-pressures and rising levels of H_2S and CO_2 are all on the hit for Technip's VP of technology development. Elaine Maslin spoke to Laurent Decoret.

Laurent Decoret. Photo from Technip.

Laurent Decoret has an enviable job, not least in today's cash-strapped environment. He is Technip's VP Technology Development.

While many are cutting costs, Technip has increased its research and development (R&D) budget, from under €60 million (US$63.4 million) in 2010, to more than €75 million ($79.3 million) in 2014.

On Decoret's desk is everything from unmanned surface vessels and to aluminum power core umbilicals. The French engineer, graduated from the Ecole Centrale de Lyon, gave a rundown of some of the future technologies' we can expect from Technip.

The aluminum core power cable is a technology the firm hopes to bring to the industry early next year, Decoret says. Already used onshore for power networks, Aluminum core power cables have been used in offshore wind farms, to save weight and costs. As projects move into deeper waters, with subsea processing adding to power requirements, copper cable can reach limitations.

"We are in the final stages of qualification with the last full scale testing [mid-November]," Decoret says, with qualification to 3000m water depth and including a wet mate 18/30kV connector system. "The key benefit of using aluminum is that it has much better mechanical performance than copper in terms of strength and weight and capability to accommodate loading, as well as a significant increase in performance in fatigue behavior and a reduction in weight," he says. "This is something we see as very pertinent for deepwater power umbilicals, especially with more and more subsea processing."

Technip's umbilical prototype manufacture and qualification uses a 300sq mm 18/30kV triplex extruded and dry cured design with Aluminum 6000 series corrosion resistant conductor material, supported by high-strength steel strands to take stress off the working core. Specifications on future projects will depend on umbilical length and power requirements.

To create extra strength aluminum core power umbilicals, it has high strength steel strands to support the cable, taking the stress off the working cable section.

Technip is also looking at carbon fiber armor for flexible pipe, instead of steel, to reduce the weight of flexibles in ultra-deepwater by up to 50%, as well as having greater mechanical strength. Such technology could also be used for oil offloading lines, which traditionally use steel armor, which then has to be supported in the water by buoyancy modules, because of its weight. Work in this area led to Technip being awarded a contract to supply the first flexible pipes for Petrobras' ultra-deep water and fluid harsh Libra pre-salt field offshore Brazil. Technip is also working on next generation carbon fiber armor to cope with high temperatures and pressures as well as CO_2 and H_2S, and its potential use in other layers of pipe.

For flexible pipe monitoring, Technip is in the final qualification phase of its Morphopipe technology, a MEMS- (microelectronic mechanical systems) based riser curvature monitoring system, which uses MEMS sensors mounted on the outside of the riser, protected by a sheath, at a critical bending point to provide live and historic motion data. The current design is a hard wired system, but future systems could be wireless.

Decoret says Technip is adding fiber optic sensing to electrically traced pipe-in-pipe technology, to bring more accuracy to pipe heating, as well as trace-heated blankets. The firm is also developing an in-service riser inspection system (Iris), as well as an anti-H_2S sheath – a polymer with special components which captures H_2S – and nano materials to improve insulation.

"For Technip, differentiating through technology is a strategic priority," Decoret says, through both in-house development, but also by working with specialist providers in the likes of polymers and composites.

For Decoret, the key challenges for the industry today are aging infrastructure, as well as tackling deepwater reserves, and complex and difficult reservoirs, with high pressures and temperatures, H_2S and CO_2, all while remaining reliable.

"Today, 2000m water depth, in West Africa, the Gulf of Mexico, Brazil, these are now regular," he says. "Today, we see that we are going to go beyond that and many operators are looking at reserves in deeper waters towards 4000m."

Decoret's career has seen him working for Coflexip out of Aberdeen as a flexible pipe design engineer, before rising up the ranks to head the firm's UK engineering department. In 2007, he returned to Paris to coordinate the engineering of the Total E&P Angola Pazflor SURF project, one of the largest subsea contracts to be undertaken by Technip at that time. 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 Subsea 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 & Protection
- ☐ 110 Production
- ☐ 111 Reservoir
- ☐ 99 Other *(please specify)*

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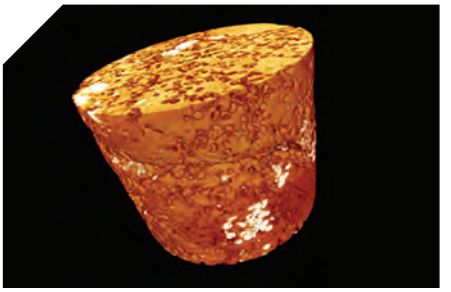
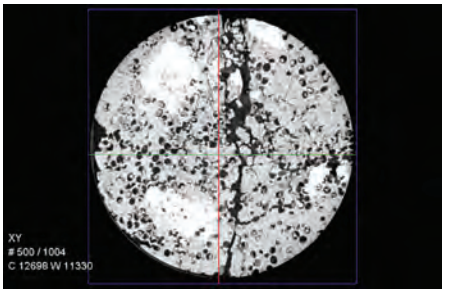
Up close and pore-scale personal

Voxels, submicrons and synchrotronic optics are coming to an oil and gas laboratory near you. Well, almost. Elaine Maslin reports on the University of Aberdeen's new high-spec scanner.





High-resolution core scan images from the university's X-ray microscope.

Images from the University of Aberdeen.

Voxels, submicrons and synchrotronic optics are the language of microscopic X-rays, which might seem alien to the oil and gas industry, but in fact they are being used to help understand reservoir properties and more at a micrometer scale.

Earlier this year, the University of Aberdeen's School of Engineering took delivery of a Zeiss, Xradia Versa 410 XRM (X-ray microscope), which its Californian maker says bridges the gap between high-performing X-ray microscopes and less powerful computed tomography (CT) systems.

The instrument was bought thanks to a £1.1 million grant to a consortium of universities, of which the University of Aberdeen is one, from the Scottish Funding Council, via the Oil and Gas Innovation Centre, for use in teaching and research related to the oil and gas industry. It is the only scanner of its type in Scotland and a resolution down to 1 micrometer (or 1000th of a millimeter).

So what can it do? 3D X-ray microscopes are enabling micrometer scale resolution scanning of rock samples, the computed models of which can then be used for simulating reservoir properties to aid understanding around areas such as enhanced oil recovery and geological storage of CO_2.

All or part of rock samples weighing up to 15kg can be scanned on the machine, with a 300mm maximum sample size. A single 3D volume takes 2- 24hrs depending on the resolution. The instrument can achieve 0.9 µm true spatial resolution with minimum achievable voxel size of 100 nanometers.

While use of this sort of technology has been around for about 5-10 years, companies are gradually getting interested in using it, says Professor Dubravka Pokrajac, from the University of Aberdeen's School of Engineering. "It is still primarily a research tool, but it is moving towards industrial use, such as understanding the processes occurring in the reservoir during production or enhanced recovery of hydrocarbons," she says.

"Using the 3D models created from the scans we can run computer simulations without running a physical experiment or we can compare with experiment and check if the 3D model is representative of real rock. Once this is confirmed, the 3D model becomes a virtual experimental sample that you can feed in to the computer and run virtual permeability or core flooding experiments and understand the absolute and relative permeabilities, which are crucial for enhanced oil recovery."

A lot of money can be saved by enabling the modelling of core flooding without actual core samples. Furthermore, the scanner provides a detailed information on how exactly the injected fluid moves through the core through time. This kind of information is not available from conventional core flooding tests.

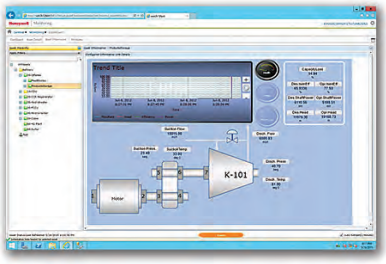
MSc and PhD projects at the university will be looking at pore structure configuration and its statistics for various types of rocks, permeability studies, single phase flow, multiphase flow – all of which are relevant for reservoir engineering.

The Versa XRM 410 will also be used for other areas of research, such as materials science. In this area, tension or compression tests on various materials, such as aluminum or polymer can be carried out while they are still inside the scanner, so that the resulting crack propagation within the material can be determined from successive scans. With the results, the scientists can calculate mechanical properties important for fatigue and durability of various materials.

The University's Department of Geology and School of Engineering are also interested in using the scanner for research into geological storage of CO_2. "One of the things we would like to do, depending on securing additional equipment, is to understand how CO_2 moves at reservoir conditions such as high-pressure and high-temperature," Pokrajac says. "It would also help towards understanding how CO_2 is trapped within a reservoir and how much of it can be stored. To do this, i.e. simulate CO_2 injection into depleted oil fields or brine aquifers as potential storage places, the university would need to build a flow loop and perform core floods inside the scanner."

The university is also getting a second scanner, which is due to arrive in January 2016. This is a complementary unit – it is able to scan bigger samples but with a coarser resolution. By using both together, the university will be able to combine fast but relatively coarse scoping investigations with very detailed microscopic studies of selected regions of interest. This will enable studying samples such as rock cores at different spatial scales, and open a possibility for a new level of understanding of upscaling, which is the key issue in many practical applications, for example in reservoir engineering. OE

asset sentinel



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