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Rig Market Review

Offshore Engineer • February 2015

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Contents

February 2015

ON THE COVER

Alternate view. As we consider the health of the rig market, we feature Maersk Drilling's DNV-classed Maersk Interceptor on the cover. The Gusto MSC CJ70-X150MD, ultra-harsh environment unit is to work on Det norske's Ivar Aasen development in the Norwegian North Sea under a five-year contract. *Photo from Maersk Drilling.*


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Departments & Columns

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Online Exclusive

Sustained low oil prices provide canvas for industry to reinvent itself

Matthew Jurecky, GlobalData's Head of Oil & Gas Research and Consulting, takes a look at current mergers and acquisitions activity in the oil and gas industry.

What's Trending

Business as usual

- Egypt signs six new oil and gas agreements
- Statoil adds to Krafla reserves
- Maria jumps in resources

People

Bruheim named EMGS CEO

Bjarte H. Bruheim took over as EMGS' CEO following the board's decision to accept ex-CEO Roar Bekker's resignation in early January. Bruheim has served as the company's executive chairman since July 2004.






Undercurrents

Is there a silver lining?

It's clear the offshore oil and gas industry is feeling the pinch, globally. Oil prices at US$50/bbl and less have put many new projects in doubt, seen any near-term prospects for exploration in the Arctic put in doubt and have made even existing assets no longer profitable, according to figures from Oil & Gas UK (see page 12).

For the North Sea and Aberdeen the concerns have been enough to trigger a North Sea oil summit, where city, industry and government leaders will discuss how to best deal with a tide of lay-offs. The UK's Energy Minister also called for an urgent North Sea review, ahead of plans to announce new tax relief measures – called for even before the oil price slide.

Yet, there are unexpected beneficiaries of the downturn in the oil industry, particularly in the UK. While the marine renewables industry there has been suffering in recent months (wave firm developer Pelamis went into administration in November 2014), there are signs of hope for the nascent sector.

Undercurrents has heard from UK-based marine renewables firms who have been inundated with job applications from oil and gas workers looking to get back into the workforce after their summary dismissal from oil firms looking to adjust to the new oil price environment.

A complaint from the marine renewables industry has been lack of interest in work from oil and gas industry contractors. Now they are and vessel rates are falling to levels that are more affordable.

And it's not just the marine renewables industry that might benefit. Some say yards, which have been long-awaiting the North Sea decommissioning bonanza, could now get an (very) early Christmas present as operators potentially move to decommission assets earlier than they had planned.

The oil industry itself could also ultimately benefit, according to the Norwegians. The Norwegian Petroleum Directorate (NPD) says, while there may be a short-term drop in activity, action now could strengthen Norway's consistently high-cost petroleum industry over the long-term.

"A cost reduction now could lay the foundation for ensuring robust profitability over time," says NPD Director General Bente Nyland.

It's a view we've heard repeated by some in the UK sector. OE

Read more:

Urgent North Sea Review commissioned www.oedigital.com/component/k2/item/8008-urgent-north-sea-review-commissioned

Norway remains upbeat http://www.oedigital.com/component/k2/item/8017-norway-remains-upbeat-despite-activity-drop

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Voices

Looking ahead. Oil prices may be rattling the industry, but innovation waits for no one. OE asked:

What emerging technology will have a direct impact on the offshore market?

It's clear with falling oil prices and rising costs, that the global oil and gas industry will face tough challenges and decisions in 2015. Interest in subsea boosting and processing, such as gas to liquid separation, liquid to liquid separation and seawater treatment and injection, continues to gain momentum as a means to deliver cost efficiencies and optimization of systems. Though these developments are not new, the technology is still in its infancy. It is therefore important that the industry works together to standardize the technologies and create a more open market, which will deliver tangible benefits for all.

Luca Sintini, Technical Director, Xodus Subsea

The offshore market is currently suffering from low exploration drilling rate and success, high development costs, low production efficiency and high operating costs. Existing methods and technologies may move these issues to an incremental degree. The revolution we need in these areas includes improved subsurface imaging techniques that build confidence in exploration drilling and provide a higher rate of success for exploration wells; an order of magnitude simplification in developments and associated development costs; and a focus on operating discipline and reduced brownfield costs to improve production efficiency, as wells as methods of reducing wasted time and materials while in the operating phase.

Chris Hamlet, Senior Advisor – operations, ADIL

Three-dimensional seismic continues to evolve rapidly in terms of both technical and economic viability, and we'll see this trend continue to lead the way in 2015. In the towed-streamer marine world, broadband acquisition and processing techniques now permit the recovery of higher-frequency data, yielding greater resolution than geoscientists could have imagined just a few years ago. These broadband techniques also allow seismic service contractors to run streamers deeper, thereby reducing noise and weather downtime. At a reservoir scale, we're seeing wide-azimuth multicomponent data acquisition and processing that deliver data extending well beyond acoustic impedance to define rock properties and fracture information.

Dave Ridyard, SVP Business Development & Marketing, ION Geophysical

For short-term gains in the next five years, we need to adapt existing technology already being used by other industries. A key area will be realizing safe, effective unmanned operations, a transition the space industry had to make to survive.

For me, complete remote operation offshore is achievable – we have onshore compressor stations operated remotely already, and should be able to master a similar approach so it is routinely applied offshore. The use of advanced composites will also be critical, as they can reduce the integrity issues associated with traditional materials and lead to lower costs and improved safety.

Myrtle Dawes, Projects Director, Centrica Energy

The short answer is automation. Mechanized equipment is now standard on category 4 and 5 deepwater rigs. However, the level of equipment integration varies from installation to installation. Common among all installations is individually customized solutions. Moving from mechanized operation toward automated operation will increase efficiency, reduce costs, and improve safety. Today more development activity is focused on automating the drilling process than on automating the pipe handling and the auxiliary operations. I believe automating the pipe installation will yield efficiency gains comparable to those from automating the drilling process.

Karsten Heidecke, Director of Engineering, Weatherford

Subsea gas compression, as it can produce gas reserves in subsea fields with substantially higher recovery rates than with conventional developments; it also enables longer tieback distances. OneSubsea's first-of-its-kind multiphase compressor is designed specifically for subsea and with simplicity in mind. It can tolerate up to 100% liquid and operate continuously with up to 5 Vol percent of liquid on the suction side. No scrubber with associated complexity is required, nor is a conventional surge system. The multiphase compressor has the same operational robustness as a multiphase pump, and will first be installed commercially in the North Sea in 2015.

Jon Arve Svaeren,Vice President, Processing Systems, OneSubsea

Nanotechnologies and development of unconventional resources top my list of future emerging technologies. Nanotechnologies have applications from designing pore scale solutions to high performance materials. The hype around nanotechnology solutions has been there for decades but only now do we see commercial and cost efficient products being trialled and becoming available. Despite unconventional resources not forecasted to dominate operator's offshore CAPEX spend, enabling technologies such as processing and export of heavy oil, subsea developments and smart well designs are expected to drive lifetime costs down while targeting higher recoveries from these challenging reservoirs / fluids.

Shahbaz Sikandar, Subsurface Director, Maersk Oil North Sea UK

Go to OEDIGITAL.COM and give us your opinion on this month's topic!

ThoughtStream

Mike Tholen, Economics Director, Oil & Gas UK

North Sea: Challenges ahead

There can be little doubt – either for us as energy professionals in the sector, or anyone who has picked up a paper over the last few months – that the UK oil and gas industry is facing a serious challenge.

The falling oil price, while great news for the general public, is affecting activity across the UK North Sea and companies have to take hard decisions in this challenging business environment. In addition, to sustain the economic benefits the industry has provided for many decades, urgent action is needed to deliver fiscal change by the 2015 budget. That is why we, at Oil & Gas UK, are committed to working closely with HM Treasury to do just that.

In parallel, there needs to be swift implementation of the Wood Review recommendations, while industry concentrates on addressing the costs and efficiency of its operations across the North Sea. Those factors become ever more pressing in light of current developments.

In January, we saw the oil price fall below US$50 per barrel – significantly less than half it was six months ago and the lowest in some years. The UK Continental Shelf (UKCS) is a mature basin with mature assets, and these will struggle increasingly if investment to maintain them falls. What's more, unfortunately, both exploration and new investment will also be under increasing pressure as prices fall.

Even in the "$100 world," we were beginning to face a reigning-in of investment to conserve capital and improve capital efficiency; UKCS investment was already expected to halve over the next four years. In an "$80 world," according to our data, about a third of these opportunities are unattractive. Perhaps even more worrying, existing operations are also under pressure, in a "$60 world," 10% of UK production – including vital infrastructure hubs – could be running at a loss, needless to say that that percentage gets higher as we head below the $50 mark.

"The UK Continental Shelf is a mature basin with mature assets, and these will struggle increasingly if investment to maintain them falls. What's more, unfortunately, both exploration and new investment will also be under increasing pressure as prices fall."

While it might be hard to be confident of the outlook in such a business environment, we as an industry must work in collaboration with all our stakeholders across industry, and crucially across government, to find a cure for our current ills. Our sector is not in danger of total collapse, as has been suggested by some. We believe it can and will adapt – but at what cost? The "cure" must of course be effective and lasting – crucially, it needs urgent, positive and collaborative action in the weeks and years ahead.

We need to ensure that those fields acting as hubs for North Sea activity remain active and that industry is supported by the government to increase its competiveness and secure future investment.

It is positive news that the government agrees fiscal policy must now be framed in the context of the sector's wider economic contribution. Indeed, the first steps were taken in the Autumn Statement with the proposal of a simplified investment allowance and a limited reduction in the headline rate of tax. However, these measures were suggested when the oil price was more considerably higher than it is now.

We now need to see, without delay, delivery of the full range of fiscal measures required to sustain this industry, including, crucially, the investment allowance by Budget 2015.

Ultimately, however, should our industry not be treated fairly as any other business in the UK? We'd argue that in time the 30% supplementary corporation tax must be discarded, alongside the outdated petroleum revenue tax, to ensure our home-grown industry can compete with international markets.

Every barrel we fail to produce from our own resources will have to be imported. Imported barrels do not sustain any UK jobs and pay no production tax.

If government approaches our industry with a long term view – this approach will be mirrored from within our sector - as companies will become increasingly confident in investing in the UK North Sea for the long term. That's what we need to see – for the benefit of UK jobs, UK energy security and the UK's economy. OE

__Mike Tholen__ is economics director for Oil & Gas UK. Prior to joining the industry body he worked with Shell for 20 years, latterly holding a variety of commercial positions including economics and planning manager for their upstream UK gas business and Offshore Infrastructure Manager in the Netherlands.

Global Briefs

A Chevron cancels Beaufort plans

Chevron is canceling plans to drill for oil in the Beaufort Sea in Canada's Arctic because of economic uncertainty in the industry amid low oil prices.

The move follows Husky Energy's decision to defer an investment decision on the West White Rose project offshore Atlantic Canada. COO Rob Peabody said the firm was going to evaluate cost efficiencies on a proposed platform for the field.

B Woodside in Nova Scotia farm-in

BP accepted Woodside's offer to acquire a 20% interest in exploration licenses 2431, 2432, 2433 and 2434, in the Scotian basin, off Nova Scotia, Canada. BP will remain operator.

The licenses cover 14,000sq km in 500-3600m water depth. The future work program is anticipated to include drilling exploration wells from 2017.

C Chevron's Anchor hits big

Chevron made a significant oil discovery at its deepwater US Gulf of Mexico Anchor prospect.

Chevron says the high quality oil pay was found in multiple Lower Tertiary Wilcox Sands at well No. 2. The firm is expecting to begin appraisal drilling later this year.

The well is 225km offshore Louisiana in Green Canyon Block 807, in 1580m water depth and was drilled by Pacific Drilling's *Pacific Santa Ana* drillship, to a depth of 10,287m.

D Success offshore Brazil

Petrobras has made new oil discoveries in the Espirito Santo Basin, according to partner Inpex.

The discoveries, in the BM-ES-23 concession, 115km offshore the State of Espirito Santo, found 36° API oil at 4300m deep.

Petrobras, Inpex and PTTEP, are conducting an ongoing appraisal drilling campaign on the block.

Also offshore Brazil, production testing began on Karoon Gas Australia's Kangaroo-2 appraisal well, in exploration Block S-M-1165. Karoon said flow rates reached 1820-3700 stb/d through 40/64-88/64in. chokes.

The oil is 33° API with zero CO_2, H_2S, water or sand produced on a first production test and 31° API oil with zero CO_2, H_2S, water or sand produced on a second.

Work is underway to start a side-track program in both down-dip and up-dip locations to better define the resource size and recovery factors.

E Steel cut on Catcher

Earlier January, Premier Oil saw first steel cut on the North Sea Catcher project FPSO. Preparations for development drilling on Catcher are due to start in 2H 2015, with the project on schedule for first oil in 2016.

Premier Oil was planning to submit a plan for development for the Vette (previously named Bream) FPSO development offshore Norway during January.

First oil on Premier's west of Shetland Solan field, is now targeted for Q2, after weather delays. Solan is expected to produce about 24,000 boe/d, from what will become the first normally unmanned platform west of Shetland.

F First oil on Eldfisk II achieved

ConocoPhillips achieved first oil on its Eldfisk II project in the Norwegian North Sea.

Eldfisk II, along with Ekofisk South and other projects offshore Norway, will add about 60,000 boe/d production by 2017, ConocoPhillips said.

The Eldfisk II project includes plans to drill 40 new production and water injection wells from the new Eldfisk 2/7 S platform.

First oil was also achieved from the Det norske-operated Bøyla field offshore Norway.

Bøyla, a subsea tie-back to the Alvheim FPSO is estimated to contain 23 MMboe and is expected to produce at a gross peak rate of about 20,000 boe/d.

G Valemon comes on stream

The Statoil-operated, US$2.95 billion Valemon high-pressure, high-temperature, gas and condensate development in the Norwegian North Sea achieved first production early January.

Valemon, containing about 192 MMboe recoverable reserves, is being produced by what will become Statoil's first platform remotely controlled from shore, turning into a "normally unmanned platform" when drilling the 10 production wells on the field completes in 2017.

Condensate from Valemon will be piped to Kvitebjørn for processing, and from there to Mongstad. Gas will be sent to Heimdal for processing.

H *West Alpha* to drill Balder

ExxonMobil received consent from the Petroleum Safety Authority Norway to use the *West Alpha* semisubmersible drilling rig on the Balder field, in the central North Sea.

The *West Alpha* will be used to drill and complete new

production wells on the field, to install subsea equipment and plug wells no longer in use.

Balder is a subsea development tied back to an FPSO.

I Egypt signs six agreements

Egypt's government has signed six new agreements for oil and gas exploration in the Gulf of Suez and the Western Desert, the Oil Ministry said.

The agreements were with Shell, Italy's Eni, BP and Canada's Trans Globe, along with Tharwa and General Petroleum Co., the state-owned companies, with minimum investments of about US$5.271 million and a signature bonus of $124 million to drill 41 wells.

J Nene Marine quick start

Italy's Eni has started production from Nené Marine field, offshore Congo, just eight months after obtaining the production permit and 16 months after the exploration discovery.

The 1.5 billion boe field, in Marine XII Block, about 17km offshore, in 28m water depth, is expected to reach a production plateau of 140,000 boe/d from over 30 production wells. During the production test, the Nené Marine 3 well delivered in excess of 5000 bo/d with a density of 36° API. The Minsala Marine 1 exploration well, produced over 5000 bbl of light oil with a density of 41° API.

K Woodside farms into Rabat Deep

Morocco approved a farm-in deal between London-based exploration minnow Chariot Oil & Gas and Australia's Woodside on the Rabat Deep Offshore permits I-VI.

Woodside is committed to pay 100% of the 3D seismic acquisition and processing costs incurred across the license by Chariot, as well as other back costs and future work up to an agreed cap, including a multibeam side-scan sonar and seabed coring survey.

L ION to survey Somalia

ION Geophysical and Somalia's Puntland Petroleum and Minerals Agency (PPMA) agreed to complete a multi-client 2D regional seismic survey offshore Puntland, Somalia, starting 2Q 2015.

ION says Puntland is considered highly prospective and regionally, it is similar to Yemen and Oman, where oil reserves have been discovered in Cretaceous and Jurassic formations.

According to ION, the PuntlandSPAN survey is the first of its kind within Puntland's jurisdiction and will assist the PPMA in delineating a block boundary scheme for future licensing activity.

M Israel debating Leviathan

The Israel Anti-trust Authority advised Noble Energy and its Leviathan field partners of its decision to not submit the Consent Decree to the Anti-trust Tribunal for final approval in late December.

Noble and its partners have requested a hearing with the Anti-trust Authority.

"The actions of the Anti-trust Authority are another disturbing example of the uncertain regulatory environment in Israel," says Charles D. Davidson, Noble Energy chairman. "Specifically, this is a matter that we believed was resolved some time ago and follows on recent assurances from the Anti-trust Authority that approval was forthcoming. We will vigorously defend our rights relating to our assets."

N BP, SOCAR to explore Caspian Sea

BP and Azerbaijan's state oil company (SOCAR) signed a production sharing agreement (PSA) for the exploration and development of the potential prospects in the shallow water area around the Absheron Peninsula.

The PSA contract area stretches along the margins of the Caspian basin to the south of the Absheron Peninsula. This new agreement is part of the government's plan to ensure that all of Azerbaijan's offshore areas are fully explored.

O First Croatian blocks awarded

Five companies have won licenses covering 10 exploration blocks in the Adriatic Sea in Croatia's first licensing round, where six companies bid for 15 exploration areas.

A Marathon Oil and OMV

consortium was granted a license in North Adriatic 8, Central Adriatic 10, Central Adriatic 11, Central Adriatic 22, Central Adriatic 23, South Adriatic 27 and South Adriatic 28.

An Eni and MEDOILGAS consortium was granted a license in one exploration block, Central Adriatic 9.

INA – Industrija nafte was granted a license in South Adriatic 25 and South Adriatic 26.

P Woodside signs India LNG MOU

Woodside Energy and Adani Enterprises signed a memorandum of understanding to identify, investigate and develop potential business arrangements and commercial initiatives in India's LNG market.

"India is an important emerging LNG market in which we see enormous supply potential as infrastructure is developed," says Peter Coleman, Woodside CEO and managing director.

Q South China Sea remains active

CNOOC discovered hydrocarbons at its deepwater Lingshui 25-1 well in the Qiongdongnan Basin in the South China Sea. The well was tested to produce about 35.6 MMcf/d of natural gas and 395 b/d of oil. Lingshui 25-1 follows the Lingshui 17-2 discovery from March 2014.

The discovery follows November's success at the Lufeng 14-4 structure in the eastern South China Sea, where oil production tested at approximately 1320 b/d, CNOOC said. At the Liuhua 34-2 gas field in the eastern South China Sea, Husky Energy began producing approximately 30 MMcf/d and expected to reach its designed peak production of approximately 45 MMcf/d sometime in 2015.

R Hess, NWS sign LOI

Hess Exploration Australia and the North West Shelf (NWS) signed a non-binding letter of intent for Hess to develop natural gas discoveries in its deepwater permits offshore northwestern Australia.

Hess wants to toll the production through existing NWS processing and liquefaction facilities in Karratha, Australia. Hess would then market LNG to customers in Asia Pacific.

S Polarcus in Australasia 3D seismic project

Polarcus is to conduct a broadband 3D marine seismic acquisition project in Australasia for an undisclosed client.

The two-month project is set to begin this quarter, and is subject to the execution of a service contract.

This follows recent agreements with Perenco and Camax Energy Gambia, as well as an agreement for two 3D seismic projects in West Africa.

T Bass Strait campaign begins

ExxonMobil subsidiary Esso Australia began a five-well drilling campaign at the Turrum field as part of its ongoing investment in Bass Strait. The drilling program is expected to continue into 2H 2015.

The US$275 million investment in drilling four gas wells and one oil well follows the start-up of the $3.69 billion Kipper Tuna Turrum project. First oil from Turrum, exported via the new Marlin B platform, was announced in October 2013.

Turrum holds an estimated 1 Tcf natural gas and 110 MMbbl oil and gas liquids. The drilling program is being undertaken from a drilling rig on the Marlin B platform.

Contract Briefs

Schlumberger inks Mariner deal

Schlumberger Oilfield UK is to provide integrated drilling and well services on the Statoil-operated Mariner heavy oil development in the UK North Sea. Schlumberger will deliver all the main drilling and well services, including drilling, completion, electrical submersible pumps, cement and fluids. A total of 22 drilling and well services are included in the scope, including logistics support. The four-year contract started January 2015 and has several four-year extention options.

Swiber breaks into West Africa

Singapore-based offshore construction and support services firm Swiber Holdings made its first foray into West Africa through a US$710 million contract from a Houston-based oil and gas firm to provide engineering, procurement, construction, installation and commissioning (EPCIC) services for an offshore processing facility and associated subsea infrastructure developments.

Enbridge to build Stampede pipeline

Hess awarded Enbridge an estimated US$130 million contract to build, own, and operate a lateral pipeline, which will connect the Stampede development to an existing third-party pipeline system in the Gulf of Mexico. The Stampede oil pipeline will be about 16mi.-long and 18in.-diameter, starting in Green Canyon Block 468, about 220mi. southwest of New Orleans, Louisiana, in about 3500ft water depth. The pipeline is expected to be operational in 2018.

Keppel Singmarine secures US$48.7 million contracts

Keppel Singmarine has secured two contracts worth a total about US$48.7 million. The first was from Dubai-based Seaways International to build a multi-task anchor handling tug (AHT). Designed by Robert Allan, the AHT will have a 100-tonne designed bollard pull and is due to be complete in 2Q 2016. It will be the fifth AHT Keppel Subnarube gas supplied to Seaways. The second contract is from Nakilat-Keppel Offshore & Marine to provide technical services for the construction of a liftboat. It will be the first time Keppel Singmarine has provided technology solutions for a liftboat. Services will include detail and production engineering, technical and commissioning support and procurement support.

Eni, Ocean Rig extend contract

Eni Angola and subsidiaries of Ocean Rig UDW agreed to extend the contract for the drillship *Ocean Rig Poseidon* by one year until 2Q 2017.

According to the agreement, Ocean Rig agreed to adjust the existing day rate for the extension in exchange for Eni agreeing to enter into two contracts for use of one or more of Ocean Rig's available drillships in West Africa starting 1Q 2015 for approximately eight months.

Alphastrut on Ivar Aasen

Alphastrut is provide 450sq m of raised access flooring on Det norske's the Ivar Aasen Northern North Sea development. ted by a 30mm gap, to aid air conditioning. The system is being fabricated by SMOE in its Singapore yard.■

An accelerated approach

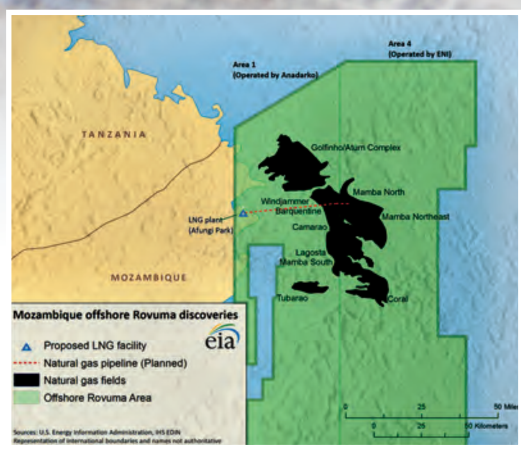
Area 4 is the jewel in Italian explorer Eni's African crown. Meg Chesshyre reports on the company's plans to get its large gas discoveries off Mozambique to market.

Mozambique's Area 4 is the world's fifth largest natural gas discovery in the last 30 years with more than 85 Tcf estimated natural gas resources in place.

The scale means Area 4 offers world-class discoveries with large gas resources and exceptional reservoirs, said Eni senior vice president Stefano Maione, who is in charge of the Area 4 development, at a presentation at ONS 2014 in Stavanger.

But, it also presents unique challenges, technical, non-technical, environmental and social. It also offers exceptional opportunities with an advantageous location and the prospect of an accelerated development strategy, he says.

Area 4, covering 10,000sq km, is in the Rovumba Basin offshore Mozambique, about 50km off the coastline at Palma, more than 200km from the capital Maputo, and close to the Tanzanian border. Eni East Africa is the operator with a 70% interest. The other joint venture partners are: ENH (10%), Galp (10%), Kogas (10%) and CNPC (20% indirect participation through Eni East Africa).



Area 4 includes three main gas discoveries – the Mamba complex, Coral and Agulha. It lies next to the Anardarko-operated Area 1, and five of the eight discovered pools of Mamba straddle the Area 4/1 border. Eni started drilling in Area 4 in 2011, with the *Saipem 10,000* drillship.

Discoveries

The first well, Mamba S-1, encountered large gas volumes. Since then there have been multiple 2D/3D seismic studies. A total of 14 exploration and appraisal wells have been drilled and six drill stem tests executed, resulting in the identification of eight reservoirs with turbidite sands. The gas is lean, without H2S, with excellent reservoir characteristics giving an extraordinary deliverability.

The Area 4 reservoirs are characterized by sand-rich deepwater fan deposits. In the Mamba complex a hydraulic continuity has been proven between wells as far apart as 22km. Moreover, the reservoir thickness found by the wells is 600m with a gas column up to 560m, Maione says.

To maximize the monetization of the 85 Tcf of discovered gas resources and to secure early first gas, Eni is working on a multiple development approach. The initial plan is to have two onshore hubs at Afungi and Quionga, plus an offshore hub. Diversified LNG technologies will be used with onshore trains and floating LNG units, with diversified products (LNG, gas-to-liquids, compact natural gas, and others). There will be parallel development of straddling and non-straddling reserves.

Initial phase

In the initial phase for Area 4 straddling reservoirs, there will be two onshore LNG trains (5 MTPA each), 16 production wells, subsea production systems, umbilicals and sea lines. Near shore sea lines will be developed in synergy and common facilities onshore will be shored with Area 1. An engineering, procurement and commissioning tender for the LNG facilities and a front end engineering and design (FEED) competition for the subsea facilities are ongoing. The final investment decision (FID) is scheduled in 2015 and start-up in 2020.

The development of the Coral non-straddling reserves will comprise a floating LNG (FLNG) unit (2.5 MTPA), six production wells, subsea production systems, umbilicals, risers and flowlines. A FEED competition for the FLNG and for the subsea production systems is ongoing. The FID is expected by year-end, and start-up in 2019.

The area poses considerable technical challenges. The development wells will need to be drilled in ultra-deepwater, between 1500-2500m water depth. The subsea facilities design will have to take into account the seabed morphology, which is characterized by the presence of deep canyons (See "Challenges in the deep" on page 68 for more). Approaching the coastline, the presence of the continental shelf requires the crossing of a steep escarpment, while the last 10km of the sea lines are in shallow water. Detailed design characterization has been carried over the last two years from the deep offshore to the coast in order to define the optimum design of all the subsea facilities.

Adding to the complexity is that the area has limited infrastructure. The closest city with only minor facilities like an airport and a port is Pemba, which is about 250km south of the area of operations. But, authorities in Mozambique have plans to make it a logistics center for the industrial sector in the north of the country. In parallel, Eni is planning to build a marine offloading facility in Palma to support offshore operations.

"The challenges we have to face are not only technical," Maione says. "The lack of a specific energy legislation, the magnitude of investment and the game-changing and the greenfield nature of this project for the whole country need to be considered as well."

Area 4 and Area 1 operators are therefore in talks with the government of Mozambique and are negotiating a dedicated legal, fiscal and contractual framework for the development of the natural gas resources. The need to respect biodiversity and social factors is also a priority. Activities are currently limited to small-scale agriculture and fishing, and islands with exclusive tourist resorts.

Maione notes that Area 4's geographic location makes it a natural supplier to feed the fast-growing needs of the Asian gas markets. "There is a supply gap in the LNG market after 2020, when our initial phase should come on stream, and delivery prices to India and Southeast Asia are very competitive compared with other sources," he says. In addition, the Area 4 joint venture has direct control and ownership over its upstream reserves, and is developing one of the very few large LNG projects which can count on gas supplies for the next 40 years.

The *Saipem 10,000* drillship being used in Area 4 by operator Eni. Photo from Saipem.

Eni is adopting an accelerated approach to a phased Area 4 development in parallel with exploration activities to allow an early arrival of the gas to market. It signed a heads of agreement with Area 1 US-based operator Anadarko Petroleum in December 2012, establishing foundation principles for the coordinated development of common natural gas reservoirs offshore Mozambique. This will facilitate a development program whereby Eni and Anadarko will conduct separate yet coordinated offshore activities, spanning both Area 4 and Area 1. Furthermore, the two companies will jointly plan and construct common onshore LNG liquefaction facilities in the Cabo Delgado province of northern Mozambique.

Maione concluded that the size of the Area 4 discoveries enables parallel and accelerated development of multiple hubs, incorporating both onshore and offshore LNG facilities with low unit costs due to significant project scale and quality of the reservoirs. There are also additional monetization options/technologies opportunities including gas-to-liquids and compact natural gas to drive the economic growth of Mozambique. **OE**

Floating toward FLNG

The KD Consortium, consisting of KBR and Daewoo Shipbuilding & Marine Engineering Co., was awarded a front-end engineering design (FEED) contract by Eni East Africa for a floating liquefied natural gas (FLNG) facility for the Coral South Development Project in Mozambique.

The KD consortium will be one of three consortia competing for the engineering, procurement, construction, installation and commissioning (EPCIC) contract to build the new FLNG facility for Eni East Africa and its partners.

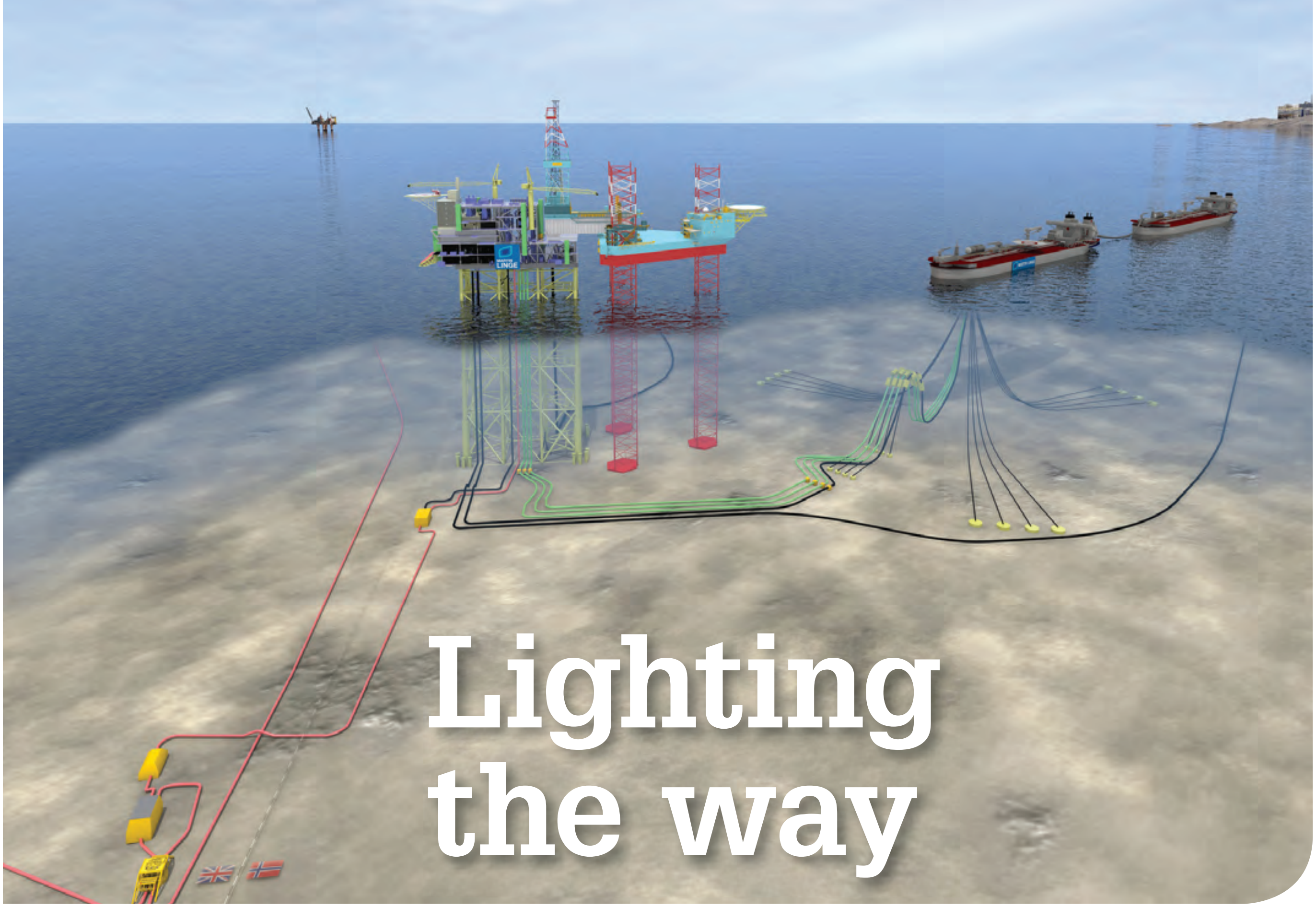
Only one consortium will be chosen to take the project to the EPCIC phase. The milestones of the combined FEED-EPCIC competition are:

1) FEED activities started in May 2014.
2) FEED completion date is set to be end of April 2015.
3) EPCIC offer submission is foreseen by end of May 2015.

The KD Consortium will provide the FEED for the topsides, hull and subsea for the floating LNG facility. The topsides and turret are being designed in KBR's Leatherhead, UK, office while the hull and marine system are being engineered in DSME's facility in Seoul, South Korea.

The FLNG facility will be a turret-moored. double-hull floating vessel, on which gas receiving, processing, liquefaction, and offloading facilities will be mounted together with LNG and condensate storage. ▪

Lighting the way



Total's Martin Linge development. Image from Siemens.

Sending electricity to offshore installations from onshore has been proven on the Norwegian Continental Shelf, but cost is a factor. Elaine Maslin reports.

Norway has a unique dilemma - the country is producing more electricity than it needs, predominantly through hydropower plants.

In a normal year, the country uses 120 terawatt (TW) hours, with production about the same. Ola Elvstuen, chairman, Energi og miljokomiteen, says there will be excess green energy in future. But, as a major offshore oil and gas producer, the country is also producing tonnes of CO_2 from platforms and process plant each year.

According to Auke Lont, president and CEO of state-owned Statnett, which runs Norway's onshore power grid, Norway's offshore oil and gas production facilities account for some 25% of the country's CO_2 emissions. The situation, against a back drop of government climate agreements to reduce emissions to 52.9 million tonnes by 2013, and to 47 million by 2020, has put offshore emissions under the spotlight.

"For the petroleum sector to move on, we think it needs electrifying. Statoil's vision is platforms on the bottom of the sea, where there is not much space for large gas turbines, so you need electricity," Lont told a Centre Court session at Offshore Northern Seas 2014 (ONS) in Stavanger.

Powering platforms from onshore, via cables out to sea, has already been proven on the Norwegian Continental Shelf (NCS). However, the economics have so far struggled to make it work. In 2010, the operators of the Edvard Grieg, Ivar Aasen and Gina Grog fields started a study to look at a common power from shore solution for the fields. At the time, it concluded that it was technically feasible using high voltage direct current (HVDC), but too costly. Using alternating current (AC) was ruled out due to high transmission loss, according to Statoil's Environmental Impact Assessment (EIA) for Johan Sverdrup, submitted in November 2014.

A proposal for a region-wide power from shore policy put forward by the Norwegian government has also proved not so easy. But, the discovery of Johan Sverdrup (originally known as Aldous/Avaldsnes) changed the baseline and the options were reassessed.

Last year, Norway's government also "pushed through" a proposal to electrify all future developments on the Utsira High area, which includes Statoil's Johan Sverdrup development, and the Gina Krog, Edvard Grieg, and Ivar Aasen developments, through power from shore, amounting to a 250MW power requirement. But, a date for when this should be implemented has yet to be agreed and there have been concerns that such a scheme would push up costs and delay the project.

Svein Knudsen, vice president at ABB. Photo by Elaine Maslin.

Lont says Norway's grid would be able to handle the 250MW requirement, in addition to an aluminum smelter being considered in the same area, onshore, but

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)	75	74	60	-
Deep (500-1500m)	23	19	23	1
Ultradeep (>1500m)	37	34	12	1
Total	**135**	**127**	**95**	**2**
Start of 2015	135	125	90	-
date comparison	-	2	5	2

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	12	587.75	4,363.28
Deep	17	1,801.00	2,935.00
Ultradeep	52	16,233.25	20,573.00
United States			
Shallow	18	101.80	254.00
Deep	18	1,219.27	1,580.48
Ultradeep	26	3,961.50	3,280.00
West Africa			
Shallow	185	5,031.82	24,632.05
Deep	48	6,236.50	8,330.00
Ultradeep	22	2,650.00	3,290.00
Total	**398**	**37,822.89**	**69,237.81**
(last month)	(400)	(38,696.99)	(70,189.81)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1236	45,354.59	620,138.46
(last month)	(1262)	46,441.71)	(611,768.39)
Deep	166	11,507.24	118,058.91
(last month)	(175)	(11,999.24)	(120,883.91)
Ultradeep	113	23,242.15	68,040.00
(last month)	(122)	(24,016.65)	(73,260.00)
Total	**1,515**	**80,103.98**	**806,237.37**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,645	(41,594)
Planned/ possible	24,686	(24,193)
	66,331	(65,787)
8-16in.		
Operational/ installed	81,813	(81,651)
Planned/ possible	48,485	(49,002)
	130,298	(130,653)
>16in.		
Operational/ installed	92,693	(92,607)
Planned/ possible	39,013	(38,461)
	131,706	(131,068)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	285	(285)
Under development	44	(41)
Planned/possible	341	(347)
	670	(673)
Fixed platforms		
Operational	9324	(9302)
Under development	120	(117)
Planned/possible	1399	(1407)
	10,843	(10,826)
Subsea wells		
Operational	4789	(4783)
Under development	361	(271)
Planned/possible	6569	(6631)
	11,719	(11,685)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	23,710.48	28,214.64	29,514.12	36,573.66	25,223.04	27,872.19	35,582.14
(last month)	(23,592.47)	(30,131.54)	(35,266.01)	(30,371.83)	(25,682.50)	(27,710.65)	(35,336.22)
Deep	484.3	4343.62	4855.45	3510.66	3703.79	6566.83	13724.76
(last month)	(484.30)	(4,152.32)	(5,046.76)	(3,882.06)	(4,745.97)	(6,875.41)	(12,891.37)
Ultradeep	2928.00	2749.62	1869.95	4499.41	9190.33	10,453.02	9225.39
(last month)	(2928.44)	(2749.62)	(1869.95)	(4470.91)	(9484.60)	(10,507.34)	(10,600.13)
Total	**27,123.22**	**35,307.88**	**36,239.52**	**44,583.73**	**38,117.16**	**44,892.04**	**58,532.29**

15 January 2015

Svein Knudsen, vice president at ABB. Photos by Elaine Maslin.

that the addition of the 500MW smelter would require grid investment, he added, which would have a longer lead time than field developments.

Statoil's current concept for powering Johan Sverdrup, according to the EIA, is via a phased approach. Phase 1, due on stream in 2019, would be based on 200km HVDC subsea cables and a power module on the Johan Sverdrup riser platform. For future power requirements on Johan Sverdrup and the nearby Gina Krog, Edvard Grieg and Ivar Aasen developments, an offshore converter and distribution platform would be required, connected to the Johan Sverdrup facilities. ABB is doing the front-end engineering on the Johan Sverdrup HVDC (high voltage direct current) link to shore. A single connection to Johan Sverdrup has also been looked at.

The technology is established, Svein Knudsen, vice president at ABB, told ONS centre court. "There are two ways to send power offshore (AC and DC)," Knudsen says. "But, there is always a limit for AC (due to transmission loss). If the power requirement is too big and the distance too far, the only solution is HVDC. The technology of DC is of course more complicated than traditional AC, it has more power electronics, but it has been used onshore and offshore since the early 1950s, so it is a mature technology that's continuously developed upwards in power."

AC can stretch to about 150km, depending on power

Case study - Gjøa

Gjøa was developed and started up by Statoil in 2010, at which point GDF Suez took over. Gjøa was discovered in 1989, 45km offshore Norway, and developed using a semisubmersible production platform and five subsea templates, with power from shore.

"It was the first floating platform with power from shore," Hilde Adland, head of operations, GDF Suez E&P Norge told delegates at ONS 2014. "(Power from shore at) Gjøa has resulted in reducing emissions and a better working environment, with regularity and reduced maintenance."

The power comes from Mongstadt via a subsea cable, including 98.5km of static cable and 1.5km of dynamic cable up to the floater. "Due to the distance from Gjøa to Mongstadt we were able to use AC. If it was longer, then the requirement would have been DC and things would have looked quite different. We would have needed transformers from DC to AC at Gjøa."

"The project meant the development of dynamic cables, by Statoil, during the project phase. Without power from shore,

Oistein Johannessen, VP communications, DPN, Statoil.

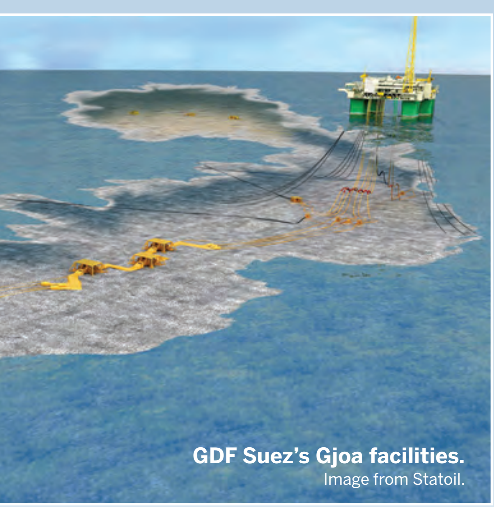
requirements, Knudsen says. However, AC power is being stretched beyond 150km for Total's Martin Linge development, which will use a 161km-long high voltage AC cable (145kV/55MW) from Kollsenes, Norway.

In 2005, power from shore via ABB's "HVDC Light" link was launched on Troll A for pre-compression. ABB is now working to provide a further 100MW to Troll using its HVDC Light to power two compressor drive systems.

A 98km-long, 90kV AC cable was used to provide 40MW of power to the Gjøa platform, which was developed by Statoil and now run by GDF Suez. It started up in 2010 and was the first floating platform to be supplied with power from shore. ENI's Goliat, also a floating facility, will get 75MW via a 105km, 123kV AC cable.

In 2013, BP's Valhall field was the first 100% powered from shore offshore platform, via a nearly 300km, 150kV, HVDC cable from Lista, with conversion to AC at Valhall to provide 80MW.

BP had investigated power from shore in 2000, initially as a regional solution, supporting UK and Norwegian North Sea platforms. But, the project resulted in just Valhall having power from shore. "We have been involved for 13-14 years," Olav Fjellsa, director of communications, BP Norge said at ONS. "The first estimates were really very high and there was a large debate to drive down costs to get the cost we ended up with.



GDF Suez's Gjoa facilities. Image from Statoil.

Gjøa would have needed four N2520 gas turbines. It still needs one, for gas export, but waste heat recovery is used on this unit.

"When we started it, there was uncertainty about how much downtime there would be due to power from shore. Nearly four years in and operationally, we have had a very good experience with reliability. We have had two shutdowns due to power from shore. The first one we were warned up front about. This was for testing at Mongstadt. The other was due to thunder and lightning onshore and we were able to have an immediate re-start.

The project had planned for 30-40MW power. "After start-up we realized we would be able to produce up to 65MW giving us future capacity," Adland says. "The biggest risk is if we have failure on the power cable. That could give a relatively long shut down."

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	113	92	21	81%
Jackup	424	356	68	83%
Semisub	181	157	24	86%
Tenders	34	21	13	61%
Total	752	626	126	83%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	35	32	3	91%
Jackup	89	64	25	71%
Semisub	28	24	4	85%
Tenders	N/A	N/A	N/A	N/A
Total	152	120	32	78%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	17	10	7	58%
Jackup	118	105	13	88%
Semisub	38	27	11	71%
Tenders	24	12	12	50%
Total	197	154	43	78%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	25	25	0	100%
Jackup	9	7	2	77%
Semisub	35	34	1	97%
Tenders	2	2	0	100%
Total	71	68	3	95%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	51	48	3	94%
Semisub	47	44	3	93%
Tenders	N/A	N/A	N/A	N/A
Total	99	92	7	92%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	108	93	15	86%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	112	96	16	85%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	21	5	80%
Jackup	24	19	5	79%
Semisub	16	14	2	87%
Tenders	8	7	1	87%
Total	74	61	13	82%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	8	4	4	50%
Jackup	25	20	5	80%
Semisub	14	11	3	78%
Tenders	N/A	N/A	N/A	N/A
Total	47	35	12	74%

Source: InfieldRigs

15January 2015

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

The Valhall power from shore decision was based on economics."

Statoil had also already decided to electrify Johan Sverdrup from day one, said Oistein Johannessen, VP communications, DPN, Statoil. "The (additional) decision was about how to provide energy to other fields in the Utsira region." He said Statoil looked at electrification as a technology concept for all of its fields, taking into considering the broader cost benefit, as well as the price of gas and electricity. The final decision on how Johan Sverdrup, and neighboring fields, is powered is due to be made early this year.

Hans Erik Horn, director, Energi Norway.

For Knudsen, power from shore is established, not just in Norway, and efficient. Knudsen cites the Saudi Aramco's Safaniyah project, powered by 230kV and 115vK cables from Nexans. "This is not because they have a parliament which says it (should do this)," Knudsen says. "We shouldn't forget the number of wind farms out in the North Sea from Germany driven by the same technology."

According to Knudsen, power from shore energy efficiency is about 90%. In comparison, he says, offshore gas turbine efficiency is about 25-35%, or 35-40% using heat recovery technologies. An added benefit is that it can reduce offshore manpower requirements because you no longer need to manage rotating equipment, as well as reducing noise.

A survey commissioned by Energy Norway and Norwegian Petroleum Directorate found that Valhall, Troll and Gjøa all experienced improved economic performance from power, improved reliability, plus reduction in noise and vibration and reduced maintenance, which improved economics, by using power

Energy Recovery and Zaptec

A number of organizations have been looking at ways to reduce energy use and emissions offshore. Sintef has been working on a waste heat recovery project, focusing on gas compressors, with research involving operators and equipment vendors.

Sintef's Marit Mazzetti says the Norwegian Continental Shelf has a total 189 gas compressors. Of those, 59 have waste heat recovery units, for processing, and only three have combined cycle units, which also produce power.

Sintef has developed a technology for gas compressors called the compact bottoming cycle, a way to produce power from surplus heat, by heating a working fluid or gas, which expands into a turbine.

Marit Mazzetti, Sintef.

Photos by Elaine Maslin

By adding a bottoming cycle you can increase power from 32-42MW, Mazzetti says, increasing overall plant efficiency from 38.6-50-%, making it as efficient as onshore "and adds to the discussion about if power from shore is efficient or not."

This technology means the number of turbines on a platform can be reduced, reducing weight. Most platforms have four turbines, Mazzetti says. We would remove one and add a bottoming cycle, producing another 10MW and reducing fuel consumption by 22% and CO_2 by 62,000-ton/yr, or 22%.

A pilot plant has been created onshore, which will require some adaption to be used offshore. If installed at the start of a platform's life, such a system could save US$17 million, she says.

As a case study, Sintef looked at a Petrobras FPSO, which already had steam onboard for processing. Adding a steam bottoming cycle meant one of the turbines on the FPSO could be removed. An up to 25% fuel saving could be made in this case, she says.

"For the industry it will be important to reduce CO_2 emissions in the future. Drilling was stopped in Alaska in 2012 because of high CO_2 emissions and regulations are coming in. The form shore,

So why was a regional approach such a problem? Hans Erik Horn, director Energi Norway, says the debate around a regional power from shore scheme may have been complicated by the complexity of licensees in the Utsira High. There has also been a lot of doubt around costs, and project timing.

Another issue is that there is no system architect, he said at ONS. "If it had been onshore, an optimal network would have been designed," Horn says. "But no such system architect exists offshore and everyone suggests their own, which means a suboptimal system for each. A process needs to be carried to find one (a system architect)."


Ola Elvstuen, chairman, Energi og miljokomiteen.

"If we are to reach our goals, there is no doubt that to a large degree new installations must get power from land," Elvstuen says. He suggests, to overcome the hurdles, incentives might be needed, and or CO_2 tax increased.

For Knudsen, there is room for improvement in the technology itself, by duplicating subsystems, such as cooling, and cabling, to offer higher reliability. "Use industrial standards, get contractors to suggest solutions, and there is no need to use gold-plated nuts if you do not need them," he adds.

"In the future I would like might be space for subsea equipment synergies with offshore wind," Knudsen says, also suggesting a power link between Norway to the UK.

Johannessen agrees. An ultimate goal would be a linked North Sea power system, collaborating with offshore wind projects, he says. "If we are able to find a cost efficient solution for infrastructure that doesn't jeopardize power supply for different regions anything can happen." **OE**

shipping industry is implementing rules and restrictions on CO_2 emissions on ships. It has come for shipping, it is reasonable to assume it will come to offshore," she says.

Bottoming cycle deployment would be best suited to a platform designed for four turbines, with one to be replaced, and on greenfield projects, Mazzetti says.

Another company, California-based Energy Recovery, is looking to recover wasted energy from processes involving pressure. Some 15,000 of its systems are in use worldwide, largely in the water processing industry, but also by the navy, cruise liners, and on barges.

The concept, applied to an amine-based gas sweetening process, would involve recovering energy from the letdown valves, allowing the used amine to escape. The recovered energy can then be used to represurize the amine, once cleaned, get it back into the treatment cylinders. This means high pressure booster pumps can be much smaller. If repressurization is not required, the pressure from the letdown valve can be used to generate electricity.


Brage Johansen, CEO, Zaptec.

Meanwhile, Norwegian firm Zaptec has spent 10 years developing miniature power electronics, originally for the oil and gas industry for downhole applications. Slow uptake in the oil and gas industry meant the firm looked to other industries and the firm now has funding from the European Space Agency to work on systems to be deployed on Mars for plasma channel drilling. Zaptec's miniaturized units can transform 5kVWto 11kW says Zaptec's CEO Brage Johansen, who presented the technology at ONS.

A system built to charge a Tesla electric motor car developed by Zaptec, for use in Norway, where the grid is different to other countries and means transformers are required to charge cars. Zaptec's transformer provides 11kW, from the standard 3kW usually supplied to home garages, in a unit that is one-tenth the size and uses one-hundredth the amount of copper and iron compared to traditional transformers, Johansen says.

The Egyptian LNG (ELNG) terminal in Idku, 50 km east of Alexandria, Egypt, comprises two LNG production trains each with a capacity of 3.6 MTPA. Photo from BG Group.

Egypt's bid to spur oil, gas activity

Egypt's bid to pay off its mountain of debt to international oil companies and improve contract terms could create a rush of activity to make up for lost time. Patrick Werr reports.

Former chairman of Egypt's state-owned gas holding company EGAS Mohamed Shoeib thinks Egypt's recent change in tack, paying off debt to foreign oil firms, will lead to a swell of activity by foreign companies in Egypt.

Egypt's debt problems date back to the country's 2011 popular uprising, when oil and gas development was disrupted. But the Egyptian government paid oil companies US$3 billion in the last year, and in November secured a $1.5 billion syndicated loan from banks to make further payments. BG Group, which holds 35.5% stake in the Egyptian LNG facilities at Idku, and Circle Oil have since declared they have received payments, but the debt, as at 31 December, still stood at around $3.1 billion.

The government's moves came ahead of a new auction of onshore and offshore exploration and production concessions, which have already started to flow to oil firms.

The government signed six new agreements for oil and gas exploration in the Gulf of Suez and the Western Desert in January. The companies involved were Shell, Italy's Eni, BP and Canada's Trans Globe, along with Tharwa and General Petroleum Co., the state-owned companies. The terms included minimum investments of about $5.271 million and a signature bonus of $124 million to drill 41 wells.

The six represent the first of 20 new petroleum agreements that will be signed over the coming period, said Egypt's Oil Ministry. Eni also won further concessions to explore two new blocks in the Egyptian Mediterranean.

"The coming period will see robust activity for foreign companies and for service companies. I expect it to affect the production of natural gas positively," says Shoeib, now managing director of the energy division at Cairo-based Qalaa Holdings.

Analysts caution that the recent drop in international oil prices may make attempts to attract more activity anywhere in the world an uphill battle.

"At $70 a barrel, the number of projects which companies will mothball is huge," says Johnny West, of OpenOil, a Berlin-based energy consultancy, before prices further dropped to below $50.

Many companies, owed billions by the cash-strapped government, slowed down development of existing concessions and lost appetite for new ones. No new agreements were signed in 2011-2013.

The government built up $8 billion in overdue payments to finance a mushrooming program to provide low-priced gasoline, electricity, diesel and natural gas to consumers.

With the population growing and consumer inflation at around 10%, the subsidies have been eating up about 20% of the state budget. The turmoil that ousted President Hosni Mubarak in February 2011 compounded the problem, making it more politically difficult than ever to increase fuel prices.

To keep the low-price energy flowing to the domestic market, the government, in exchange for promises of future payment, diverted locally produced oil and gas that international companies had been selling abroad, turning the firms into reluctant financiers.

Egypt produced 2214 Bcf of dry natural gas at its peak in 2009, or 2.1% of the world total, but production is in decline by about 3%/yr, according to the EIA. Some 60% of Egypt's gas comes from offshore wells, Shoeib told OE.

The economy has been stabilizing since the Defense Minister, Abdel-Fattah al-Sisi, took power in July 2013 and thanks to abundant aid from Gulf Arab countries. The government raised domestic fuel prices in July 2014, reducing its subsidy bill by almost 30%. It also paid a total $3 billion in arrears to oil companies in December 2013 and September 2014, reducing arrears to $4.9 billion, Oil Minister Sherif Ismail told an energy conference in November. Companies investing in new drilling and exploration get priority, the finance minister last year said.

In late November 2014, the government secured a syndicated loan of up to $1.5 billion that will be used to further reduce arrears. In an interview in late November with Middle East Economic Survey (MEES), Oil minister Sharif Ismail suggested a two-year timeframe to pay off the rest.

Egypt has also begun modifying the terms of new contracts, giving companies greater freedom to sell their product abroad. It has been renegotiating old contracts to increase prices as well. Eni, DWE Dea, Apache and Dana Gas are among those who have obtained better prices for their gas or entered talks with the government over the past few months.

The oil minister told MEES he expected a new bid round by the end of December, with as many as 15 onshore and offshore tracts up for grabs. OE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Deepwater drilling markets – Darkness before dawn

Over supply of oil, diminishing returns and an increasing rig fleet will challenge rig operators in 2015. Rystad Energy's Joachim Bjørni and Oddmund Føre look for a ray of light.

Throughout 2014, drilling companies were punished in a bearish market where few fixtures and downward pressure on rig rates was the reality. Following the post-summer crash in oil prices, share prices have dropped accordingly (Figure 1). Due to diminishing margins, free cash flows have been key to the oil companies' performance for a while, and with an oil price scenario resembling that of 2008, we now expect to see further reduction in investments and an ever increasing focus on capital allocation. As a direct result, an increasing number of rigs without contracts have been stacked; simultaneously, we expect the entry of newbuilds to worsen an already oversupplied market.

In the short-term, drilling companies will face some rough waters. Predicting the future of the drilling markets is right now almost the same as predicting the future of the oil price, and therefore we turn to fundamentals of oil supply and demand to find answers. Our analysis suggests a recovery of the deepwater drilling space into a healthy market in the longer run.

Oil supply and demand

The oil market has experienced the largest supply shock ever seen over the past four years. US shale oil production alone has added more than 1 MMb/d each year on average – more than the growth of global oil demand over the period. Nevertheless, oil prices remained high, mostly as a result of record-high production outages following the Arab Spring. Surprisingly, demand growth weakened during 2014, US shale production accelerated, outages fell and additions from other projects came onstream. The result was an over-supplied situation, which came sooner and more forcefully than the market had anticipated (Figure 2).

On 27 November 2014, OPEC refrained from cutting production despite projections showing a need for a cut of 1.5-2 MMb/d in 2015 to balance global supply and demand. The global oil market is now in uncharted territory as it has lost its traditional swing producer, and oil prices are left to balance supply and demand.

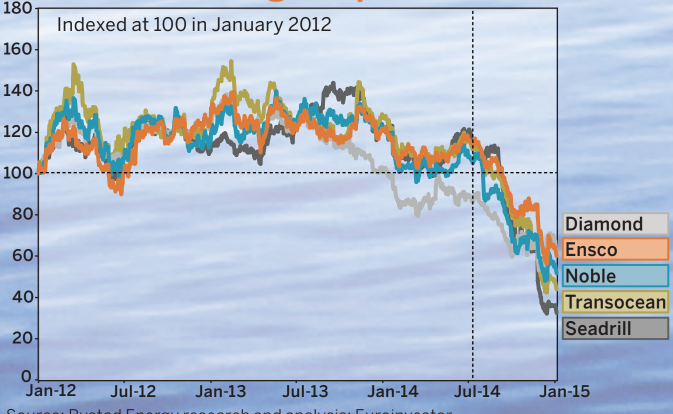
Following the cash flow squeeze for exploration and production companies, we expect 2015 to be an extraordinarily tough year for international oil companies. The global oil supply response will come from a combination of the following: Lower North American shale activity, reduced infill drilling offshore, shut-in of tail-end fields, delays in sanctioning greenfield projects and possible delays in sanctioned projects already under development. Aggregating 2015 budgets, we find that global exploration and production activity is expected down by about 10% in 2015. The budget cuts highlight the challenges expected for 2015, and the scene is now set for further offshore exporation and production cuts. The question is: where will it end?

Industry opinions differ, our analysis shows that we could still see a worsening in 1H 2015; however, we expect oil prices to turn around when seasonal demand picks up. If oil supply and demand is going to balance in 2020, at the US Energy Information Administration's (EIA) estimated demand at 98.1 MMb/d, supply will need to grow with 6 MMb/d from today's production levels. To achieve this, we need to see an oil price of above US$100/bbl, based on individual field-by-field analysis by 2020.

Short term perspectives

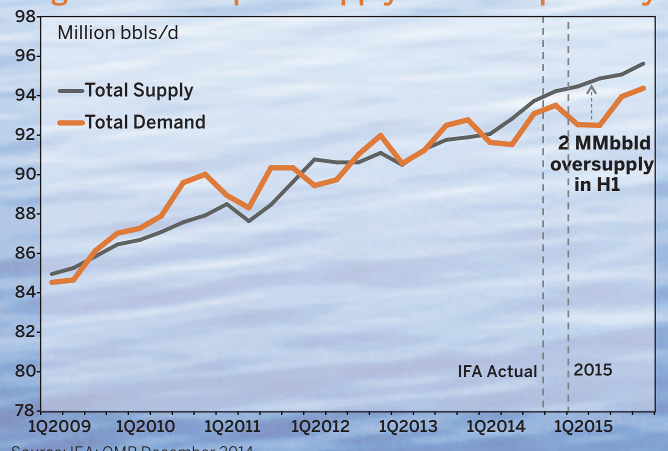
Offshore drilling is one of those capital-intensive activities that will be victims of the capital discipline to be exhibited by exploration and production companies in the short term. Our analysis

Fig. 1: Share price development of selected drilling companies



Source: Rystad Energy research and analysis; Euroinvestor

Fig. 2: World liquids supply demand quarterly



Source: IEA; OMR December 2014

suggests that exploration and production companies will reduce drilling activities in deepwater areas by 2% in 2015. This trend has been evident in the past quarters, where we have seen low contracting activity from exploration and production companies, and significant decrease in day rates from the new mutual contracts that have been realized due to current oversupply in the floater space. The current market situation is challenging for the rig owners, which are expected to face troublesome years to come. In terms of survival, rig owners with solid backlogs will be best equipped to ride the passing storm (Figure 3).

In late 2014, we have seen increased attrition activity of older low-specification units from rig owners, including majors such as Diamond and Transocean, which are in the process of scrapping a total of 18 floaters. This trend will continue as exploration and production companies high grade their operating fleet. This selective behavior emphasizes the current market situation, where supply growth is outpacing demand and is expected to result in further attrition pressure on low-specification units. A large number of newbuilds are expected to hit the market within the next two years, adding distress to an already challenging market. Already rig owners are trying to counteract the effects on utilization levels of this influx by postponing planned newbuild deliveries.

A vital question for the rig market exists: how long will this downturn continue? Our analysis suggests we will see an oil market return to balance in 2017-18. Combining the expected oil market balance with rig market supply side actions, we anticipate brighter days to come for the deepwater drilling market. The latest EIA oil demand estimate for 2020 is 98.1 MMb/d, up from~92 MMb/d today. To meet these production levels, it is pivotal for the oil market to see an increased contribution from deepwater production. The past years' shale production has demonstrated tremendous year on year (YoY) growth numbers of 72%. However, future growth levels for shale production are estimated to slow to around 9% YoY. Coupled with an expected decreasing trend from other onshore production at -1% YoY, the need for growing deepwater contribution is justified. Deepwater production needs to achieve a 9% YoY growth by 2025 (Figure 4) for the oil supply market to deliver on expectations.

During the past decade, about 50% of the deepwater fleet has been focused on exploration activities, an activity that has proven fruitful. With a balancing oil market and resulting increase in oil price, there are numerous high quality deepwater projects with competitive break-even prices lined up to be developed to support the increasing global oil demand. As a result we see the offshore fleet allocation increasingly weighted towards development drilling. This call on deepwater production and expected oil price increase will further provide incentives for increased infill drilling on already producing fields as the economic benefit of keeping the infrastructure alive is added to the value analysis. With the expected oil price increase our analysis suggests, as a result of exploration and production companies benefiting from better cash flows and increasing oil demand, exploration activity will again be deemed attractive.

Darkness before dawn

Adding an oil market oversupply situation on top of an E&P industry working against diminishing margins and a rapidly increasing rig fleet, market drivers indicate a continuation of the market cool-down we are experiencing.

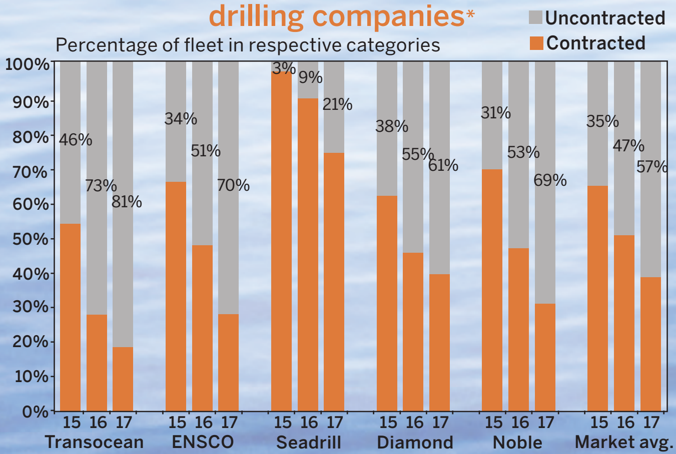
However, with an expected slowdown from shale and onshore oil supply, the oil market will need to turn to deepwater production to meet the expected long term oil demand growth. Our analysis tells a challenging story short term in the deepwater drilling space, and sees the rational in increased attrition activity and newbuild delays from rig owners.

It is always darkest before dawn; the long term, triggered by balancing oil market driving increasing oil prices, will again provide a scenario with market fundamentals pointing towards increasing utilization levels. OE

***Joachim Bjørni** is an analyst in Rystad Energy's global oilfield service team. His experience includes rig supply and demand, and global exploration and production spending. Joachim holds an MA in international business from the University of Edinburgh.*

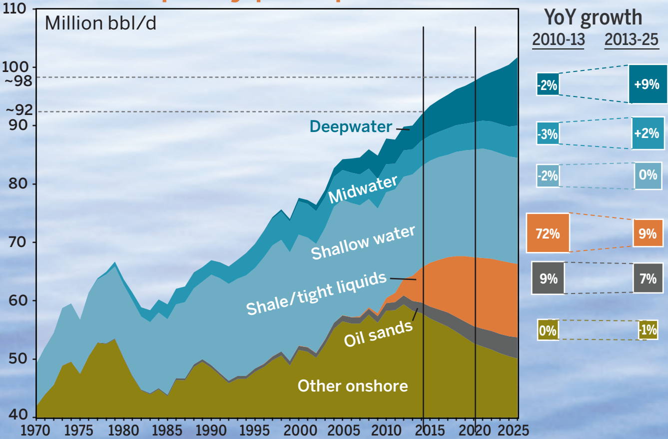
***Oddmund Føre** is an analyst in Rystad Energy's global oilfield service team – with focus on rig markets and operator spending outlook. Føre holds an MSc in finance from the Norwegian School of Economics and a bachelor's from the Norwegian Naval Academy.*

Fig. 3: Short term fleet status, selected drilling companies*



*as of December 18th 2014
Source: Rystad Energy research and analysis; Rystad Energy RigCube

Fig. 4: Global liquids production 1970-2025 split by principal source



Source: Rystad Energy research and analysis

Rig market hits hard times

Orderbooks reflect reined-in spending based on conservative near-term oil price estimates. ABS' James Graf sets out the detail.

Weak demand, excess oil supply – due in part to shale oil production – and the decision by the Organization of the Petroleum Exporting Countries (OPEC) to maintain production levels have driven the price of oil down. While there has been oil price volatility in the past, the 33% drop in a three-month period at the end of 2014 was precipitous. And the outlook is far from rosy, with the average price per barrel likely to remain below US$60/bbl through 2015 with modest increase the following year. At present, there is no expectation for oil to rise to $90/bbl until 2017 or later.

The numbers in perspective

Forecasts, by their nature, are speculative; so it is important to understand the basis for the projections. In this case, the outlook is framed by macro industry demand drivers and uses a supply vs. demand approach to project future supply needs. Oil price and oil demand are closely correlated to activity in the offshore industry on a longer-term trend basis and consequently represent a primary base demand indicator that can be used for longer-term activity projections. This outlook does not specifically address or directly consider the award, startup, or development of specific projects that collectively could create short-term volatility.

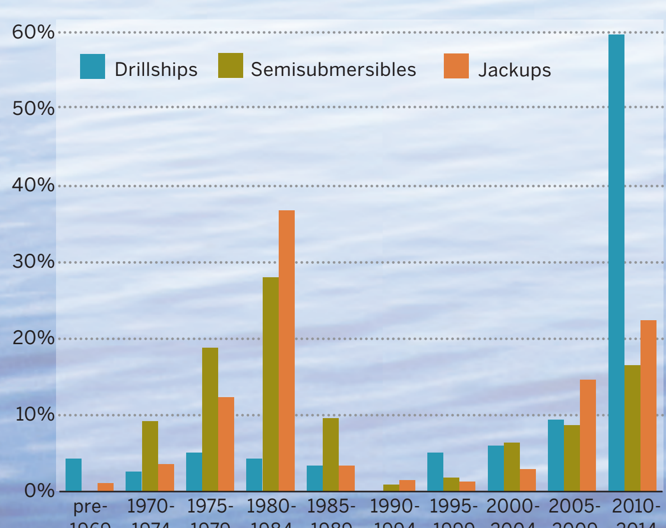
Demand outlook

Oil prices have declined significantly, and despite a few optimistic ticks upward, they have dropped steadily over the past few months. Meanwhile, production numbers remain relatively constant, and OPEC, which has in the past stepped in to alter production levels to reflect demand, has shown no interest in pursuing that route this time around. At the 166th meeting of the organization in Vienna, Austria, on 27 November 2014 under the Chairmanship of its President HE Abdourhman Ataher Al-Ahirish, Libyan Vice Prime Minister for Corporations and Head of its Delegation, OPEC members agreed to hold firm on production targets despite falling prices.

While OPEC's intentions are never entirely transparent, the organization's motivation is likely based on its desire to preserve long-term market share, which sends a signal to the North American unconventional oil producers. Weak demand growth in Europe and Japan and the slowing growth in China contribute to weak global demand, and that is expected to continue through 2015. Indications at present imply the low oil price

MODU build date distribution – percentage

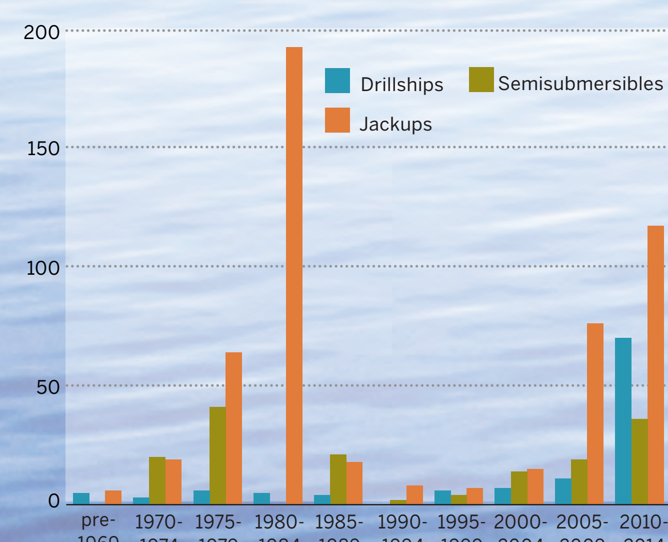
(4Q/14)



MODU new construction projects through 4Q/14. Source: ABS.

MODU build date distribution – by numbers

(4Q/14)



Distribution of current MODU fleet through 4Q/14.
Source: ABS.

environment could last as long as two years, from 2H 2014 through 1H 2016. And a low oil price (sub $80/bbl Brent) does not bode well for the offshore industry.

In the Gulf of Mexico (GOM), additional post-Macondo safety requirements – which are the primary driver behind a 13% longer time to drill – are escalating costs for projects in deepwater. It is worth pointing out that there has been a 25% increase in cost in the GOM since 2010. While some of this increase undeniably is a result of more strict regulations, there is a portion of that 25% increase that is due to the escalating cost of skilled workers. Operators in the GOM are competing for workers with operators developing shale projects onshore, where field workers have the benefit of spending more time with their families. Despite the cost increases, however, drilling in the GOM remains attractive in comparison to other parts of the world because of the potential for profit. There are many petroleum-rich nations from the Middle East to Latin America that continue to limit the amount of profit energy companies can make.

Overall, the picture that comes into focus for the next 18-24 months is one of weaker new investment. The projected low oil price environment will have the greatest impact on deepwater, ultra-deepwater and harsh environment projects, which have a higher oil price threshold for viability. The knock-on effect also will impact new investment in offshore production units and offshore support vessels.

Supply outlook

The orderbook for mobile offshore drilling and production units for the next few years will be smaller than projected six months ago. Jackups will continue to make up the lion's share, particularly those capable of working in 300ft (91.4m) or greater water depth as the renewal of the industry's jackup fleet continues. The mobile offshore drilling unit (MODU) orderbook will decline through 2016, followed by a period of slow buildup through 2018.

Weak demand growth for floating production units will keep the orderbook relatively flat for the next several years. Floating, production, storage and offloading units will continue to contribute 40%-60% of all new investment activity.

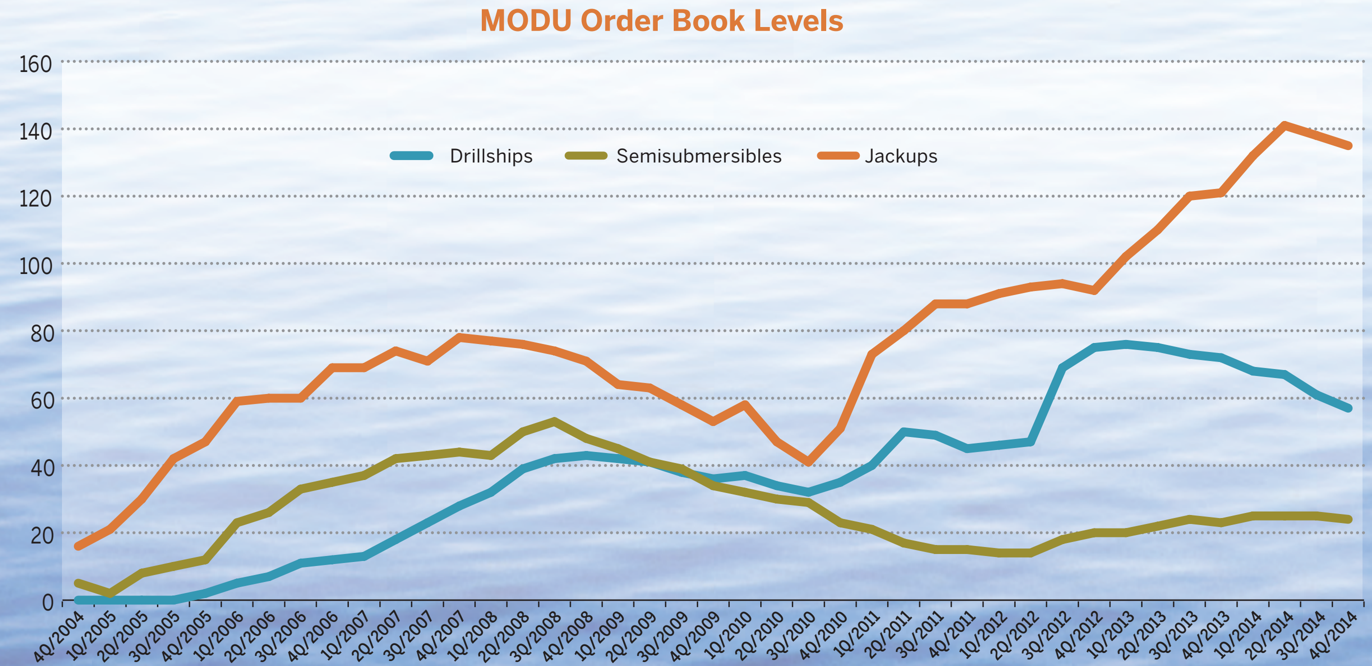
Meanwhile, offshore support vessels, which saw an uptick in newbuilds in 2014, will expand the existing fleet by almost 5%. Growth will be scaled back to a more modest 2%-3% per annum growth in 2015 and 2016.

The total mobile offshore fleet is projected to grow by nearly 1400 units by yearend. With offshore support vessels included in the number, the total offshore mobile fleet is projected to grow 4.8% to 8869 units by year end, with an additional 17% growth by the end of 2020.

Looking ahead

Volatility is inherent to the oil and gas industry; so it comes as no surprise that the long climb upward in oil prices has come to an abrupt halt. The reversal in oil prices, while dramatic, is not a show stopper for exploration and development, but it represents a significant obstacle in the near term, and it will be quite some time before there is another oil price reversal that will be sustained long enough to encourage an increase in offshore exploration and production activity. OE

__James Graf__ is ABS Corporate Vice President of Business Planning and Analysis, based in New York, where he has responsibility for global business planning and performance and industry outlooks. He holds a BE in Naval Architecture from the State University of New York Maritime College and is a member of the Society of Naval Architects & Marine Engineers (SNAME), Society of Marine Port Engineers (SMPE) and the Shipping Analysis Institute (SAI) in Stockholm.



Current MODU Fleet (4Q/04 through 4Q/14) by construction date. Source: ABS.

Keeping a cool head in the Arctic

Golder Associates' Ken Been explains the best approach to geotechnical engineering and pipeline construction when facing scours and pits in the Arctic ice.

Over the coming decades, the Arctic will become an immensely important region for petroleum extraction. As the region opens up for exploration and production, more and more engineers will face the particular challenges of the High North. To succeed in the region, companies will need detailed specialist knowledge of the Arctic environment and how this differs from the rest of the world.

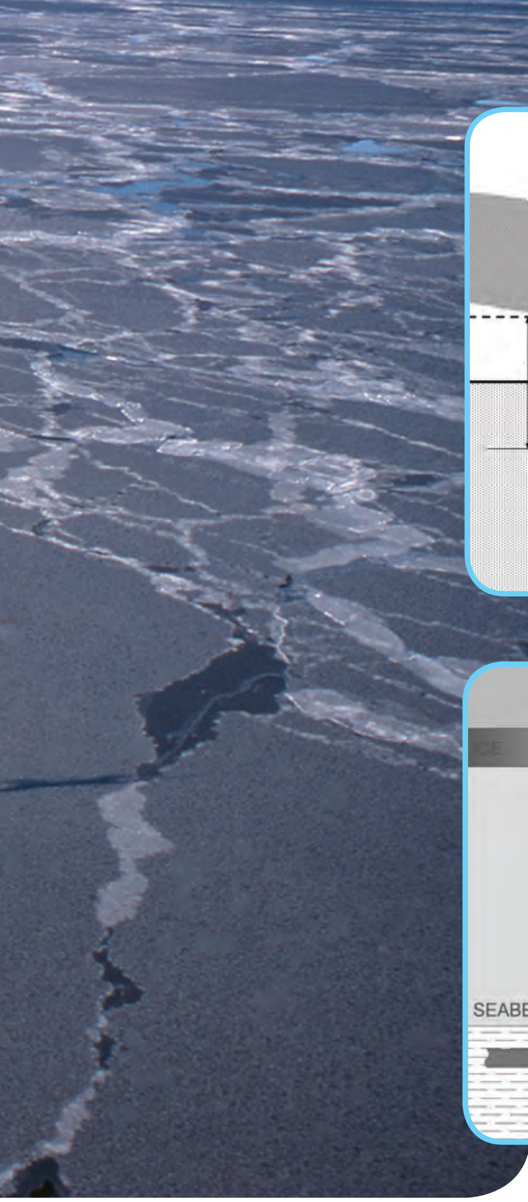
One of the main differences between operations in the Arctic and elsewhere is the different types of geohazards a frozen climate creates. This means that engineers in the Arctic have to deal with issues such as ice scours, ice pits and strudel scours to manage their surroundings and run efficient and safe operations. Scours and pits are furrows or indentations on the seabed created by the ice, and of all the geohazards in the Arctic, they are the most challenging. Success north of the Arctic Circle could hinge on methodical insights into the effects of the ice on the seabed.

Avoid it, use it or fight it

We have three simple ground rules for dealing with ice. These are, in order of priority, (i) Avoid it; (ii) Use it; (iii) Fight it. This may sound like an over-simplified approach to a whole range of complicated problems; but it is in fact a way of framing the solutions so that they are clearly defined and ordered. From this starting point, we can more readily anticipate the various challenges facing us in the Arctic.

The easiest way of avoiding ice is simply to drill south of the ice edge or out of the ice season. This, however, will not always be possible – and, besides, the Arctic is by nature changeable, so an ice free drilling site one year will not necessarily remain that way the next. When operations have to be undertaken in areas with ice, or risk of ice, excavated drill centers and burying pipelines below the deepest ice scours will be the methods to avoid the ice.

As for using ice, if it's robust enough, it can be used as a building material or foundation for roads, landing sites or to support drilling platforms. This can be a very beneficial addition when building infrastructure. But when the ice can't be used to your advantage, the remaining alternative is fighting through it with ice-breaking vessels or



Marine seismic data gathering in Arctic waters. Images from Golder Associates.

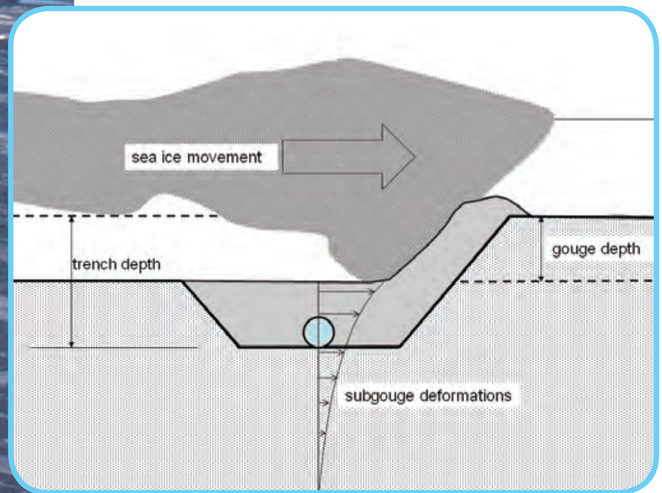


Fig. 1: Ice scouring.

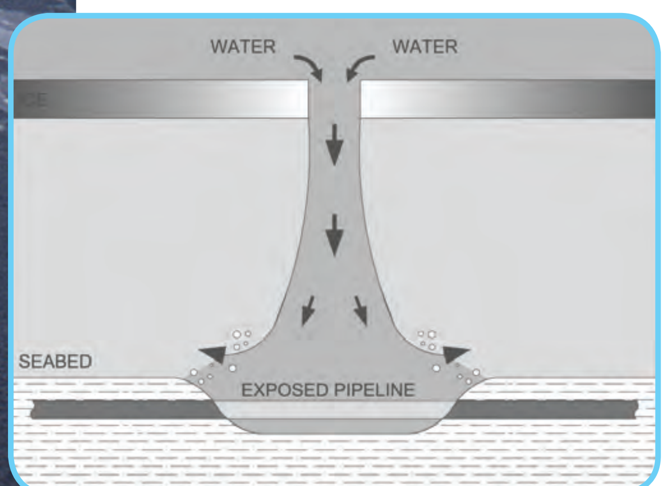


Fig. 2: Strudel scour.

platforms that can resist the force of the surrounding ice.

Ice scours and ice pits

Pipelines, however, can't readily resist the forces of the ice, as they are vulnerable to any external impact. Even if today's pipelines are designed to have some plasticity, they can only handle a limited amount of strain. They will therefore have to be buried deep enough that they are shielded from any contact with ice. Because deeper pipelines mean significant added costs, however, research into optimal pipeline depths is a key priority for many operators.

The main danger for pipelines is ice scours, which are grooves in the seabed created by masses of ice that drift across shallow water (Figure 1). The scours are roughly linear and often not deeper than about a meter, but scours up to four meters deep have been mapped in soft clay soils. Pipelines have to be placed below the extreme scour levels, and the difficult and important challenge is to determine the optimal burial depth. The pipes must not only avoid direct impact from ice keels, but also impact from soil displacement in the ground below the scours.

In addition to scouring from moving ice, large stationary masses of ice – stamukhas – form pits on the seabed. Such pits are usually considered as separate from scours – but, in practice, pits will often appear at the end, or beginning, of a scour. It can therefore be useful to consider the two as a continuum of ice loadings, only differentiated by the degrees of movement and other variables.

Optimal pipeline depth

In calculating the optimal depth for pipelines, the main headache for engineers is not the scours and pits already on the seabed. Instead, it's the scours and pits that may occur after a pipeline is in place. The potential for future ice impact necessitates a probabilistic analysis of the ice conditions and the scouring and pit data in order to determine the extreme events that define the design depth and likelihood of soil displacement above and around pipelines. Additionally, the various soil conditions will have to be mapped and analyzed to determine their propensity for soil displacement under the action of ice loads.

It's furthermore important to emphasize that designs need to consider extreme or rare ice scours and pits, and so even decade long studies of ice movements and soil displacements may not register all the relevant variables. Nonetheless, not planning for these exceptional events can be a recipe for disaster in the fragile Arctic environment.

In the Kashagan field in the northern Caspian Sea – where the water is ice-covered for about three months of the year – the team at Golder worked with the operators over ten years to survey, test and develop advanced numerical models. Based on this, we mapped a range of various load cases that had to be considered in the design of the Kashagan pipelines (see table overleaf). It's such considerations that are essential for determining the optimal pipeline depth – the depth that does not expose pipelines to unnecessary risk and at the same time isn't overly conservative.

Strudel scours

A different type of scouring that can be a particularly difficult Arctic geohazard is strudel scouring. Strudel scours occur when flood water from melting rivers during spring makes its way through the ice and produces strudel shaped depressions in the seabed (Figure 2). These scours can be deeper than ice scours and more difficult to predict, but are only found in in the vicinity of river deltas.

Since pipelines heat up their

Design Load Cases for Ice Action on Kashagan Pipelines

Consideration	Load Case	Comment
Ice regime	Landfast or mobile ice	Design scour and pit depths reduced in landfast ice zone
	Proximity to structures	Observed scour frequency increases near existing structures
Ice Scouring Subscour Soil Displacements	Clay soil or sand soil	Design scour depths as well as subscour displacements are different in sands and clays
	Trench width	Where multiple pipelines are placed in a single wide trench, scour depths are increased because backfill is softer or looser than natural seabed.
Stamukha Pits	Vertical loads	Soil displacements or ice pressure (when pit depth is greater than burial depth)
	Lateral soil displacement	Pit is adjacent to pipeline (not directly above)
	Subduction of ice sheet during stamukha formation	Soil displacements or ice pressure (when pit depth is greater than burial depth)
	Trench slope failures	Heavily grounded stamukha forms adjacent to trench in soft clay
	Concentrated ice loads	Individual ice blocks crushing against pipeline
	Ice sheet ramping during stamukha formation	Special case of vertical loads
	Transition of deep pit to ice scour	Stamukha can break up or start moving, but this case is a subscour displacement loading
	Sand backfill in soft clay paleochannel	Design case avoided through construction control on backfill type
	Punch through failure-sand layer above soft clay	Design case avoided through construction control on backfill type
Upheaval Buckling	Reduced cover due to removal	Vertical imperfection and scour or pit overlap
Multiple Load events	Plastic strain accumulation	Overlapping scours during design life of pipeline

Sampling with a boxcore in the Canadian Beaufort Sea

immediate surroundings, they may even attract strudels if the pipes are routed through a strudel risk area. The way to avoid this is to re-route pipelines away from locations where strudels are found to occur, or to dig the pipes even deeper into the soil around river deltas.

Although extreme depth strudels are a rare occurrence, as with ice scours operators must nonetheless plan their pipelines for the exceptional cases. To analyze the probability of various strudel scours, seabed surveys to map strudels could be conducted over several years to investigate their frequency over time. On the basis of this, it's possible to calculate the statistical probabilities for strudels along various potential pipeline routes. Such an analysis can be vital for determining the optimal pipeline depth.

Looking north to the future

Ice scours, ice pits and strudel scours are not the only geohazards facing geotechnical engineers in the Arctic. But for designing and placing pipelines they are pressing concerns. Another issue that can affect northern pipeline construction is subsea permafrost. The essential task for avoiding permafrost affecting pipelines is to ensure that the soil surrounding the pipes remains in its current frozen, or unfrozen, state. But the engineering challenges here, although in no way negligible, are normally less challenging than those for scours pits and strudels.

Unique and demanding geohazards lie ahead of engineers in the Arctic. This remote and harsh-climate region is our time's most exciting frontier for petroleum exploration. In the coming decades we will see activity in High North increase considerably and geotechnical engineers should prepare accordingly. Discovering the optimal route and land access point for a pipeline is an indispensable risk mitigation effort in Arctic environments. It can mean the difference between one Arctic oil spill and zero Arctic oil spills – which is all the difference in the world. **OE**

__Ken Been__ is a principal with Golder Associates. He holds a PhD from the University of Oxford. He played a leading role in supporting offshore exploration in the Beaufort Sea in the 1980s and has been involved in designing offshore pipelines in ice environments since 1989.

A sinking feeling

Ekofisk is an iconic field, but its uniqueness gives operator ConocoPhillips some specific challenges around subsidence. Elaine Maslin reports.

Ekofisk is *the* iconic field on the Norwegian Continental Shelf (NCS) – the first field to be discovered and the largest field on the shelf in terms of oil in place.

Its uniqueness is far from limited to its scale (some 6.5 billion STOIP), place in history or the fact it is now expected to still be producing for 40 years hence.

One of its most unique attributes, however, is its challenging subsurface characteristics.

The Ekofisk Complex. Photo from ConocoPhillips Norge.

A chalky discovery

Ekofisk was discovered in 1969, about 280km southwest of Stavanger. Two years later, on 9 June 1971, test production was started with full production in 1974 from the Ekofisk 2/4 A, B and C central processing facilities. Oil is transported via pipeline to Teesside in the UK and the gas to Emden, Germany.

The reservoir is in chalk, but a unique type of chalk similar to that in the Valhall field, also on the NCS. The field is dome-shaped with two major formations, Ekofisk and Tor, roughly 400ft thick each, some 2900-3250m below sea level. The Greater Ekofisk Area also contains the Eldfisk and Embla fields, and a further six fields produced from the Ekofisk complex, which have since ceased production. At its peak, the Greater Ekofisk Area had around 30 platforms in 70-80m water depth, including the first test production installation, the Gulftide jackup.

Subsidence

But, while the firm has been able to increase recovery rates from the field as its understanding in it has deepened – increasing recovery rates from about 17% to 50% today – it has also had a large issue to contend with; subsidence.

"With any large oil field particularly water flood, there are lots of typical challenges – logistics, capacity, dealing with water production, surveillance, dealing with growth, aging infrastructure," says John Leslie Hand, speaking at the SPE Annual Technology Conference and Exhibition, Amsterdam, late 2014. "These are typical challenges. What's unique for Ekofisk is the subsidence and compaction. These [Greater Ekofisk Area fields] are very unique fields. It's a consistent chalk, although highly stratified and highly fractured with lots of faulting and break-up of the rock. You have activation and reactivation of faults in the reservoir and through the over burden."

"Over 40 years, the sea floor has subsided about 9m, or about 30ft and that's huge," continues Hand. "That's quite a challenge," he adds, not least in the reservoir, some 9000ft below where the result is well buckling and in some cases well collapse, which is why there are some 100 active wells drilled to date and 250 wells bores in the field. "We also have more complex well paths, because of number of wells already there but also because of the subsidence and stress and strain," Hand says.

The problem is that the rock has not got a lot of strength and the hydrocarbons that were in place were giving support to the overburden. Once they started to be depleted, the support was also depleted.

In 1987, as production declined, Conoco started water injection at Ekofisk, which, along with the Ekofisk II redevelopment in 1996-8, helped bring production back to its peak in the 2000s, re-orientating the field center. It was thought that once water injection started they would replace the fluids and stop the subsidence. But that was not the case.

"We had been injecting water since 1987, and we still continued to have subsidence [after that]," says Hand. "The reason is the water fundamentally changes the chalk. What we see is a phenomena we call water-weakening, the water changes the integrity of the rock and changes the permeability by an order of magnitude. 10 millidarcy becomes 1 millidarcy, 1 millidarcy becomes 0.1 millidarcy."

In 1987, due to the subsidence, ConocoPhillips had to jack up all the steel jacket-based platforms in the field

by 6m – "a huge engineering accomplishment at the time." Protective walls were also installed to protect the Ekofisk tank against the ocean.

Drilling difficulties

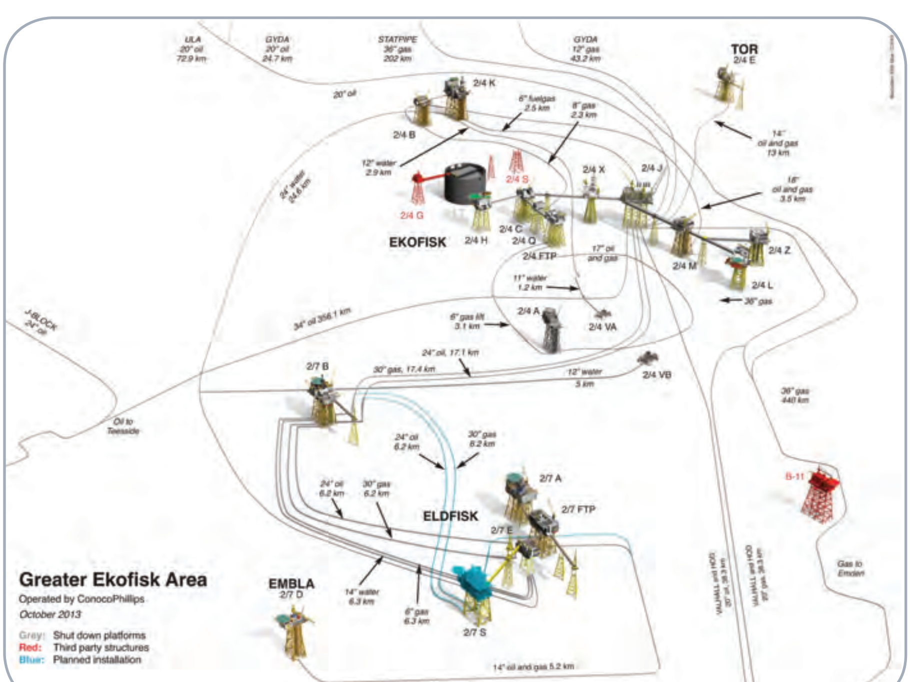
Drilling is also a big challenge in these conditions. "As we drill through the reservoir we also see huge pressure variations," says Hand. "[While] drilling a horizontal well, we maybe drilling through a water swept region and we will hit the water front and see a 1500-2000 psi pressure drop from one side of the water front to the other side over the course of a couple of 100ft. Trying to manage that through drilling is very difficult."

The changing reservoir structure, with collapsing and compaction, also results in bucking in some wells, which results in new wells with complex wells paths, avoiding existing well paths, having to be drilled. "We have incredibly thick well bores but they're still undergo buckling," Hand says. "Over time, you run wireline and you get stuck higher and higher up the well bore, making reservoir management very difficult. So reservoir management and being able to see water is important, particularly if you're replacing six wells a year."

The Ekofisk 2/4 K platform, from which water injection started in 1987. Photo from ConocoPhillips Norge.

To help improve the understanding of the water flood and to help manage and understand what was going on in the overburden and in the reservoir, ConocoPhillips installed a fiber optic cable permanent reservoir monitoring system over the entire field. It is hooked up directly to shore via a cable as well as via satellite.

"There is enough movement in this field that we can shoot a survey every six months and see something different," says Hand. "This asset has been producing for 40 years and there has been a lot of change and evolution going on. The repeat surveys helped us see better in the reservoir, under some areas that were obscured areas. But also it is very important to understand where the saturation changes and trying to map where that water front is going, not only from a reservoir management stand point but also from a containment standpoint and also when drilling new wells."



The Greater Ekofisk Area. Image from ConocoPhillips Norge.

Renewal

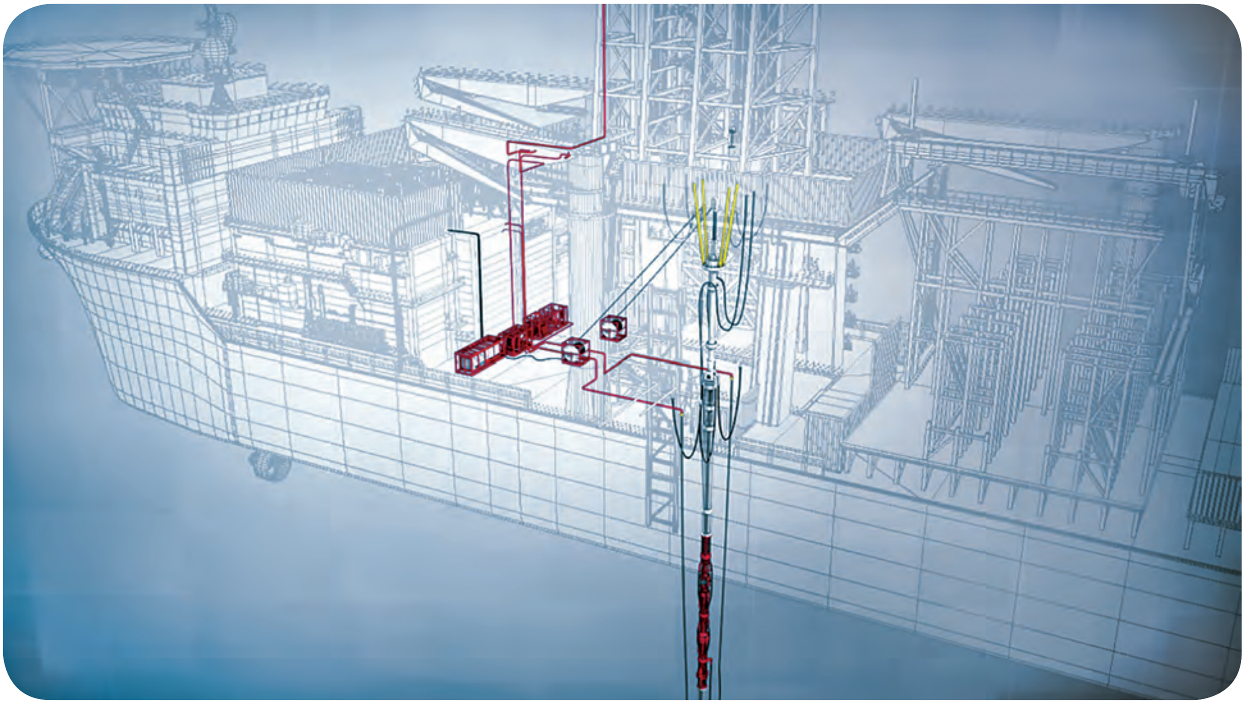
Ekofisk has not just been evolving, the Greater Ekofisk area has been going through various periods of renewal. In 2005, the Ekofisk area saw a further extension, under the Ekofisk Area Growth plan and in 2014, ConocoPhillips started up the Ekofisk South platform. The last half a dozen years has also seen some 120,000-tonne of jackets, wells and platforms removed from the field.

More recently, the area has seen further new infrastructure. "We are adding new infrastructure, including a new hotel platform," says Hand. "We have the new Ekofisk South platform, a 35-well platform, also subsea injection templates, which means you have to worry about wave height and can place the template closer where you need to drill the well and avoid subsidence areas. At Eldfisk, nearby, we're also adding some new infrastructure to extend the life of that.

About 40% of the field's resources have been produced to date. But, after more than 40 years in production, ConocoPhillips has aspirations not to wind Ekofisk down, but to continue the Ekofisk complex, which takes in the Eldfisk, Embla and Tor fields, for another 40 years.

Hand says: "It's known as the pioneer field on the Norwegian continental Shelf, the first discovery, and it really set up the Norwegian oil industry. It has had an about 43-year production history and, aspirationally, we would like to see it produce for another 40 years." But, he adds, "an 80-year life requires a lot of nurturing." OE

Industry set for new MPD guidelines



MPD equipment required for a deepwater rig integration. Photo from Weatherford.

Jerry Lee reports on new guidelines for managed pressure drilling operations due out this year from both ABS and API.

Drilling is becoming increasingly difficult as companies are reaching further into deeper reservoirs. Drilling deeper poses a challenge to engineers as wells become ever more complex. One issue is the narrow pressure window, or fracture gradient, that must be navigated to reach certain reservoirs.

The fracture gradient is the pressure range between the pore pressure and fracture pressure that exists for a particular formation. The driller will typically aim to keep the annular hydrostatic pressure above the pore pressure, to prevent a kick, and below the fracture pressure, to prevent formation damage, which may result in fluid loss. Such obstacles may prevent wells from being drilled using conventional techniques.

In the last decade, however, drillers have utilized managed pressure drilling (MPD) to address this. MPD involves using lower density mud, a surface choke manifold and surface back pressure to dynamically control the annular pressure profile. By adjusting the surface backpressure with the choke, proper equivalent circulating density (ECD) can be maintained to stay within the fracture gradient. MPD allows the driller to quickly respond to and control wellbore conditions, while having the added benefit of extending the casing setting point or removing the need for a section of casing.

As wells targeting deeper, more challenging reservoirs become common place, MPD is used more frequently. This technique, originally used onshore, is becoming a viable option offshore, thus changing the initial environment for which the MPD systems and the associated equipment were developed.

Recognizing this trend and the need to ensure operations are performed in a safe environment, DNV GL, the American Bureau of Shipping (ABS) and the American Petroleum Institute (API) are releasing their own set of MPD class rules and recommended practices at the end of 2H 2015.

"API standards are recommended practices for conducting managed pressure drilling operations that apply across the board," says CJ Bernard, global business development manager at Halliburton's Sperry Drilling GeoBalance group. "Everything from the planning aspects, to well control event identification, response and management, to equipment design, selection and testing, to equipment requirements, so they have to do more specifically with MPD operations.

"Whereas classification societies (ABS, DNV & Lloyds) speak to requirements of the equipment as it relates to interactions with the other 'classed' drilling equipment on the rig," says Bernard, who also serves as class society task force chair on the International Association of Drilling Contractors (IADC) MPD committee.

Halliburton's GeoBalance API 16RCD Testing facility where all GBA MPD equipment is designed and tested to applicable API standards. Photo from Halliburton.

Pacific Drilling's *Pacific Santa Ana* drillship, classed by ABS, has been outfitted with dual gradient drilling technology for Chevron's operations in the Gulf of Mexico. Photo from Pacific Drilling.

DNV

In 2011, DNV became the first classification society to have general rules for MPD systems on board DNV-classes drilling units with the class notation Drill(N). A more detailed set of requirements were released in the update of DNV-OS-E101 in 2013. This revision is currently being used to classify and certified MPD system, says DNV GL's Arne Handal, Ph.D, principal engineer for drilling and well intervention, in a comment to OE.

"The new standard includes requirements for managed pressure drilling systems, definitions of associated safety systems and requirements for well barriers and drawworks," said Kenneth Vareide, executive vice president of offshore class at DNV GL, upon release of the 2013 revision. "Our aim has been to take class a new step forward by focusing on control, transparency and efficiency. In addition, the intention has been to ensure that the latest best practices and innovations are rapidly implemented by the industry. The end result will be improved safety."

However, as with any pioneering works, there are kinks to work out.

"There are issues within the original rules that industry is currently working through with the class societies that hinged more so on a misunderstanding of MPD operations and intent," Bernard says.

In response to this, DNV GL spokesman Kristian Lindøe said in a statement to OE that the company works with the industry to update their rules on a continual basis.

Handal furthers this point saying: "Our updates build on experience from the application of these standards, so reviewing and addressing industry concerns are considered as part of the updating process along with safety and technology developments."

ABS

As a classification society, ABS is an independent, externally audited body that reviews plans, operational maintenance, and surveys construction processes for its clients. Currently, ABS plans to publish the ABS *Guide for Classification of Drilling Systems* (CDS Guide) with an appendix for MPD rules, Appendix 7.

Following ABS' own discussion with 50 industry companies, including a mix of both operators and drilling contractors, the CDS Guide will be updated with the appendix available in early 2015. The document will include requirements for the design, construction, and commissioning of MPD systems, subsystems, and components onboard mobile offshore drilling units (MODUs).

"ABS sees MPD as a growing trend in offshore drilling and is currently working on several MPD projects. MPD is now being used offshore to facilitate drilling of previously un-drillable wells and to enhance a well's primary well barrier," says Harish Patel, director of offshore technology at ABS. "In addition to defining a new technology qualification standards approach to high-pressure, high-temperature drilling, ABS is finalizing requirements that specify certification for MPD systems, including (dual gradient drilling) DGD systems, and associated subsea components."

With the upward trend of MPD use and the ever present concern for safety, Appendix 7 will provide ABS' clients with guidelines to plan future operations. Appendix 7 will focus on offshore MPD applications, and address needs unique to offshore drilling operations. The guidelines aim to help operators comply with the rules and requirements associated with drilling in the US offshore, as well as provide greater reliability and consistency to lower potential risks during offshore operations. Because the MPD system and all of its subsystems will be considered a part of the primary well barrier system, all associated components used in MPD operations will require ABS design approval and an ABS survey for installation, to be classed by ABS.

In the case of DGD systems, a type of MPD, no specific US requirements existed prior to the application of the first DGD

RCD5000 Big Bore with the hydraulic clamping device standing beside a hydraulic closing unit. Photo from Halliburton.

system on a MODU. ABS worked with US supermajor Chevron to class the *Pacific Santa Ana*, which has a DGD installation onboard. The ship, owned by Pacific Drilling, began a five-year contract with Chevron in 2012, and was used to successfully drill its Anchor prospect in the US Gulf of Mexico in 2014.

"The DGD system's major subsea components reviewed by ABS were the mud lift pump, subsea rotating device, and solids processing unit. The DGD project resulted in establishing a minimum standard for CVAs (the independent certified verification agents performing the safety reviews and working with regulatory bodies such as the US Coast Guard and Bureau of Safety and Environmental Enforcement) while certifying offshore MPD technology. ABS also used this experience to develop new classification requirements for MPD systems as part of the CDS Guide," Patel says.

With demand for certification involving DGD installations confined to a single vessel, plans for more extensive discussion on DGD systems will occur at a later date following the release of Appendix 7.

"As with any new technology application, applying MPD systems offshore requires careful consideration with regard to equipment and system design as well as any operational, maintenance, and safety issues – the risks – associated with offshore drilling practices and ultra-deepwater rig configuration and system integration," Patel says.

API

While ABS has been developing its MPD appendix, API has similarly forecasted the need to standardize MPD systems. In contemporaneous development with the CDS Guide, API's Recommended Practice 92M, Managed Pressure Drilling Operations with surface back pressure (92M), is set to come out by the end of 2H 2015. 92M is being developed with support from the IADC UBO-MPD Committee.

In regards to drilling rigs with surface BOPs, 92M will provide information for planning, installation, testing, and operations for wells drilled within the surface pressure category. This will allow everyone in the industry that is drilling with these techniques to have a standard practice that they can reference to as they approach complex wells and bring additional consistency, safety, and environmental awareness to offshore operations, says David Miller, director of standards at API. The main difference between the two lies in the process and company objective.

"[API's] standard development process is accredited by the American National Standards Institute, which is the body in the US that accredits standards developing organizations," Miller explains. "As an accredited standards developing organization, we are responsible for a process that, by design, is open and transparent."

And proving that point further, while the standards were under ballot from late November to 23 January 2015, they were available on the API website for review.

When the guidelines and 92M are available, companies will be able to look at their operation, and see which document suits the company's project.

Industry

When these guides and standards are issued later this year, some will have to make changes to their MPD operations.

"[Most MPD service providers are] not used to having that amount of scrutiny on MPD systems, fail-safes, and procedures," says Earl Dietrich, global director of deepwater systems at Weatherford. "However, it is making us, our suppliers, and all competitive vendors, improve their game.

"Now you will be required to demonstrate how the systems work; how you're going to test it; how the fail-safe systems work; what kind of redundancy there is."

When it comes to safety and efficiency, consistency will play an important role.

"Hopefully, some standardization will make it easier for us to specify proper equipment and have consistent installations, whether they be temporary or permanent, that are not specific to the rig contractor, operator, or country of operation," Dietrich says.

"More stringent standardization of systems, installations, capacities, and characteristics will allow personnel to more readily move between various rigs and systems."

The industry will also benefit by having more fit-to-purpose guidelines. "For example, in reference to our hoses, the highest standard is called 17K, but that standard is for continuous production of hydrocarbons to flexible hoses. We don't do that," Dietrich explains. "We may have a gas cut mud event with hydrocarbons that we deal with, but it's not continuous. However, for right now, we don't have a fit-for-purpose document or hose specification for our installations.

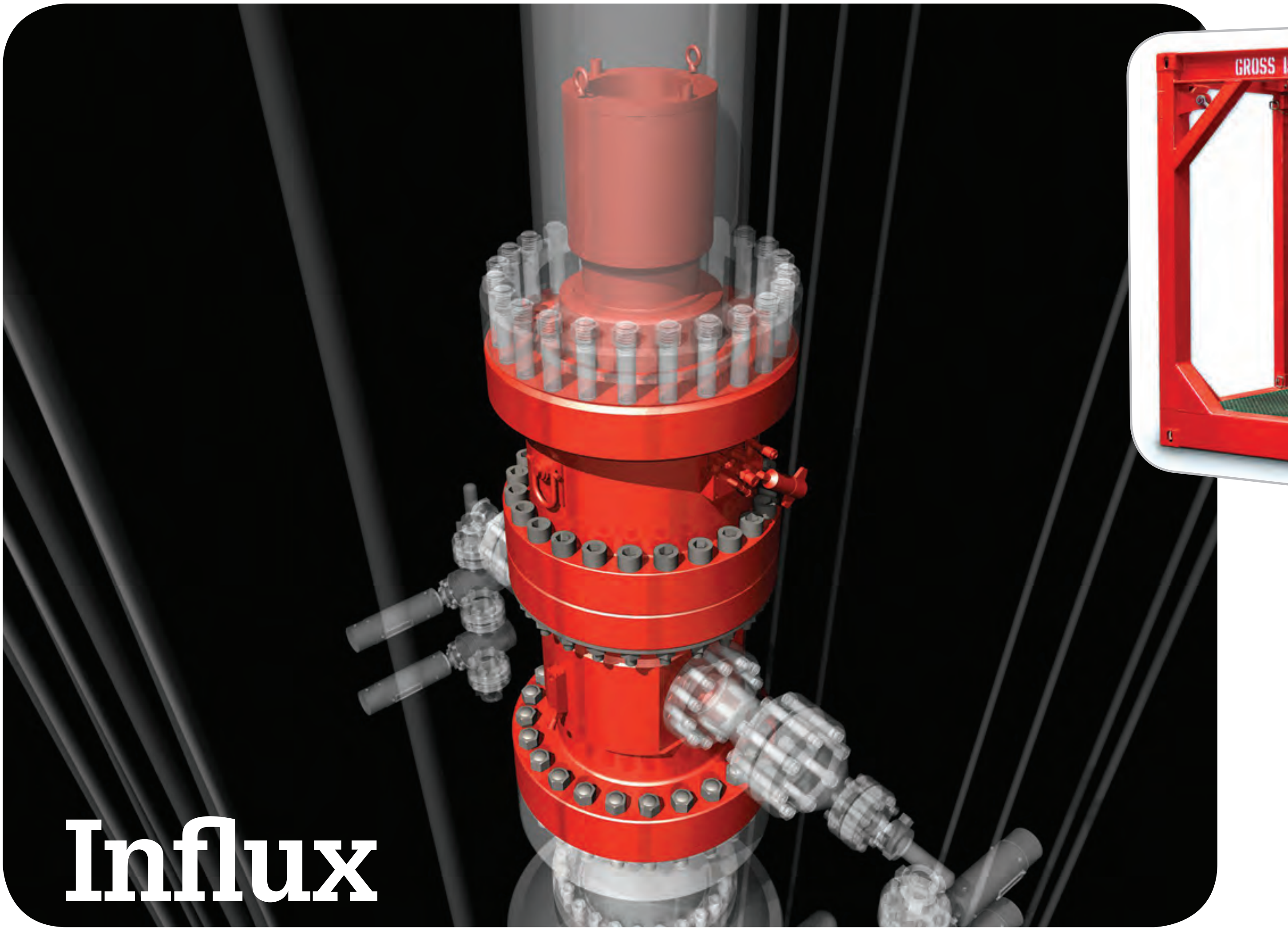
"We are continually involved with IADC, API, ABS, DNV, NORSOK, BSEE, and other groups advocating the improvement of personnel and rig safety, operations, and system standardization and requirements by providing enhanced MPD, early kick detection, and pressurized mud-cap drilling services," Dietrich says.

ABS, DNV, and API have worked with industry members to address concerns regarding the original and the newly developed MPD requirements. Halliburton's Bernard says, all organizations must come together to discuss equipment design and operational intent so that together, we can provide proper guidance and requirements to help industry meet the public's safety expectations of the industry.

With MPD technology being deployed in new inherently risker areas, it is crucial to ensure that all interactions have been reviewed and that hazards and risks are managed to acceptable levels.

"That's one of the things ABS and DNV look at, to ensure that all of the interactions between rig and MPD equipment don't create unsafe conditions," Bernard says. "In order to be class approved, you have to prove to ABS and DNV that you've done all the hazard analysis necessary to ensure that the controls and barriers are in place to manage the different hazards from these operations and equipment interactions."

As a benefit, the classification applies equally to all service providers, so it creates a level playing field and once certified it's not necessary to go through the process again for every customer's project. Most importantly, by having a set of standards that must be met and adhered to it shows the public that the intent is to provide industry rules and guidance to conduct MPD operations in the safe manner. OE



Influx detection

The MPD rotating control device (RCD) on the BOP.
Images from Weatherford

James Onifade discusses how the first managed pressure drilling operation for an African operator accurately detected and circulated a small influx out of the well, without having to shut it in or threatening the safety of the rig crew.

In their quest to reach hydrocarbon resources found in deeper waters and in reservoirs with narrow and rapidly changing pressure profiles, offshore drillers are continually searching for technologies that offer greater efficiency and safety.

Managed pressure drilling (MPD) is ideally suited to meet these needs. An adaptive drilling process, MPD precisely measures and controls the annular pressure profile throughout the wellbore during the drilling process. The technique possesses a unique ability to carefully "walk the line" between pore and fracture pressures to prevent the uncontrolled influx, or kick, of reservoir fluids into the wellbore and up to the surface of the drilling rig.

Safe and secure control

MPD provides considerable safety advantages over conventional overbalanced drilling techniques, which control the bottomhole pressure (BHP) in a well by varying the drilling mud weight to obtain the necessary hydrostatic pressure that will counter the pore pressure of the formation.

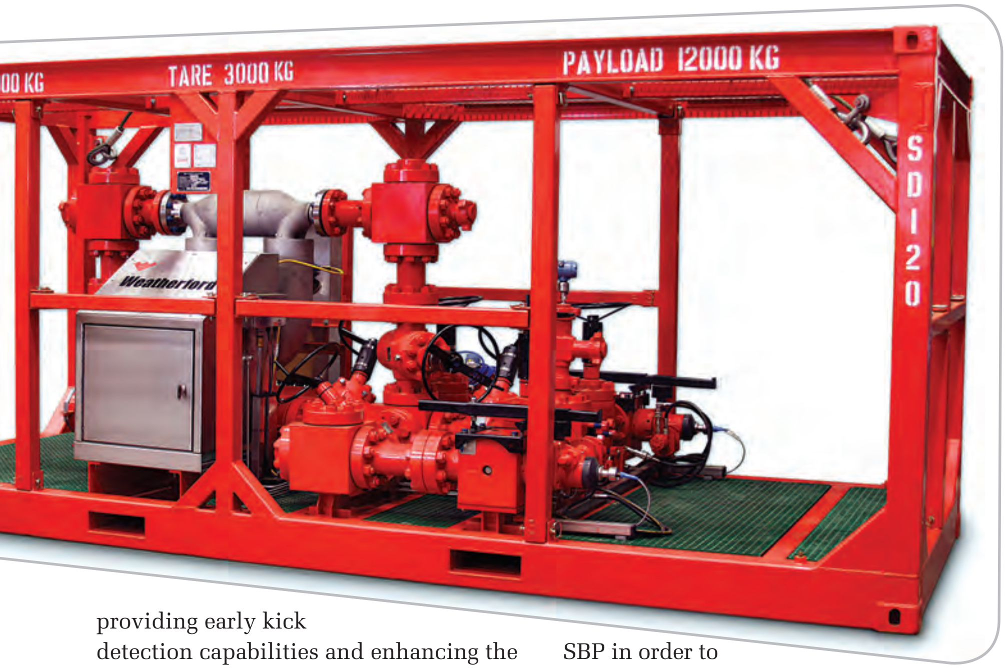
Increasing or decreasing the mud weight is an expensive and time-consuming process that cannot efficiently manage rapidly changing differences between the BHP and pore pressure. MPD techniques use a series of chokes that dynamically control the annular pressure by manipulating the surface back pressure (SBP) to increase the BHP. Choke position can be varied in a matter of seconds, a significant improvement compared to the hours required to circulate and condition the mud weight throughout the wellbore in overbalanced drilling.

MPD also provides considerable safety and environmental benefits. Return flow is diverted away from the rig floor to a dedicated choke manifold by the use of a rotating control device (RCD), thereby reducing accompanying hazards to rig floor personnel.

Flow measurement is critical to the MPD system, and is achieved through a mass flowmeter installed downstream of the chokes on the MPD manifold. The mass flow meter provides accurate flow readings and enables early kick detection. Due to the fact that influxes can be detected and controlled earlier and the annular pressure profile manipulated as required, casing setting depths can be extended. Industry studies suggest that the proper utilization of MPD may lead to the elimination or extension of casing setting points.[1]

Influx control offshore Africa

An operator working off Africa employed the MPD system for the first time,



Equipped with a mass flow meter, the MPD manifold is used to achieve precise control of a wellbore's pressure profile while drilling.

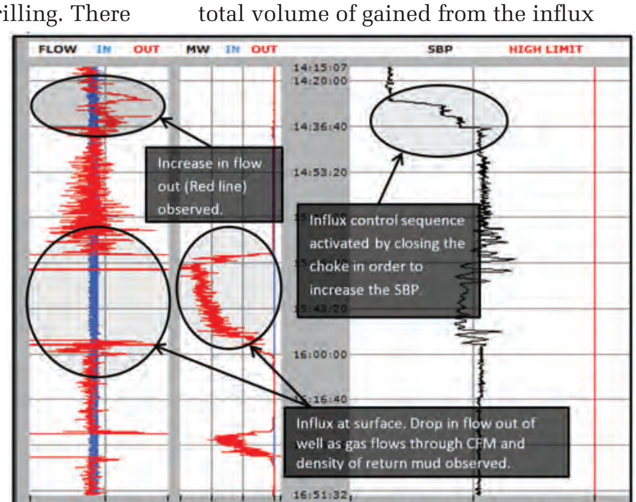
providing early kick detection capabilities and enhancing the ability to manage any influx occurrences into the wellbore during drilling operation. During a coring operation ahead of drilling the 8 ½-in. hole section of a well, the MPD system maintained a 16.2 ppg bottomhole equivalent circulating density by applying approximately 260 psi SBP. After the coring operation, the MPD system maintained 16.2 ppg (645 psi SBP) while the string and core were pulled out of hole, which kept the well in a static flow condition.

Drilling the 8 ½-in. hole section commenced, with the MPD system maintaining 16.1 ppg (approximately 590 psi SBP) while making up connections; this SBP would maintain the BHP above the pore pressure to compensate for any lost annular frictional pressure experienced during connections. A sudden increase in the flow out of the well was observed on the flowmeter while drilling. There was no change in mud density out of the wellbore, which indicated that a uniform mud density was still flowing through the flowmeter. An increase of about 20 psi was also recorded on the standpipe pressure, confirming the possibility of an influx invading the wellbore.

Once an influx invasion was confirmed, the control sequence was initiated using Microflux, the MPD system's influx control sequence, to gradually increase the SBP in order to control the influx of reservoir fluids into the wellbore. The well control sequence was activated within two minutes of the observed increase in flow out. The volume of influx when the well control sequence was activated was measured as 1.42 bbls (60 gals).

The SBP was increased from a system friction pressure loss of 160 psi (16.1ppg ECD) to about 380 psi. The well was observed to be flowing and SBP was further increased to about 560 psi (16.7ppg ECD) in order to control the influx. Once equilibrium between flow in and out of the well was achieved and while circulating at the full drilling rate of 300 gpm; the influx was circulated out of the well following the first circulation of the driller's method.

The influx was fully controlled in a total period of about 13 minutes. The total volume of gained from the influx was approximately 3.2bbls (140 gals).



MPD screenshot demonstrates flow into the well and increase in flow out of the wellbore, with the SBP required to control the influx visible in the third column.

Gas was circulated out of the well for more than 30 minutes, until the gas reading resumed the normal pre-influx level. The density trend of the drilling mud and the flow signature also resumed normalcy, indicating that the gas influx had been completely circulated out of the wellbore. A dynamic pore pressure test was then performed to obtain an indication of the pore pressure within the rock formation, and the MPD system was utilized to maintain the BHP above the pore pressure with an additional overbalance of 0.3ppg.

Conclusions

The capability of the MPD system to detect and automatically control influxes is of immense value to the drilling operation. The system utilized the automatic activation of the influx detection and control sequence to provide a faster reaction time and ultimately improve safety and operational efficiency. This faster reaction led to smaller influx volume and reduced surface pressures during the influx circulation operation. The MPD system allowed the influx to be circulated at the prevailing drilling rate, avoiding the need to shut down the pump and circulate at the slow circulation rates. Ultimately, MPD allowed for safe and efficient influx detection and control, with a reduction in nonproductive times recorded during drilling operations. OE

References

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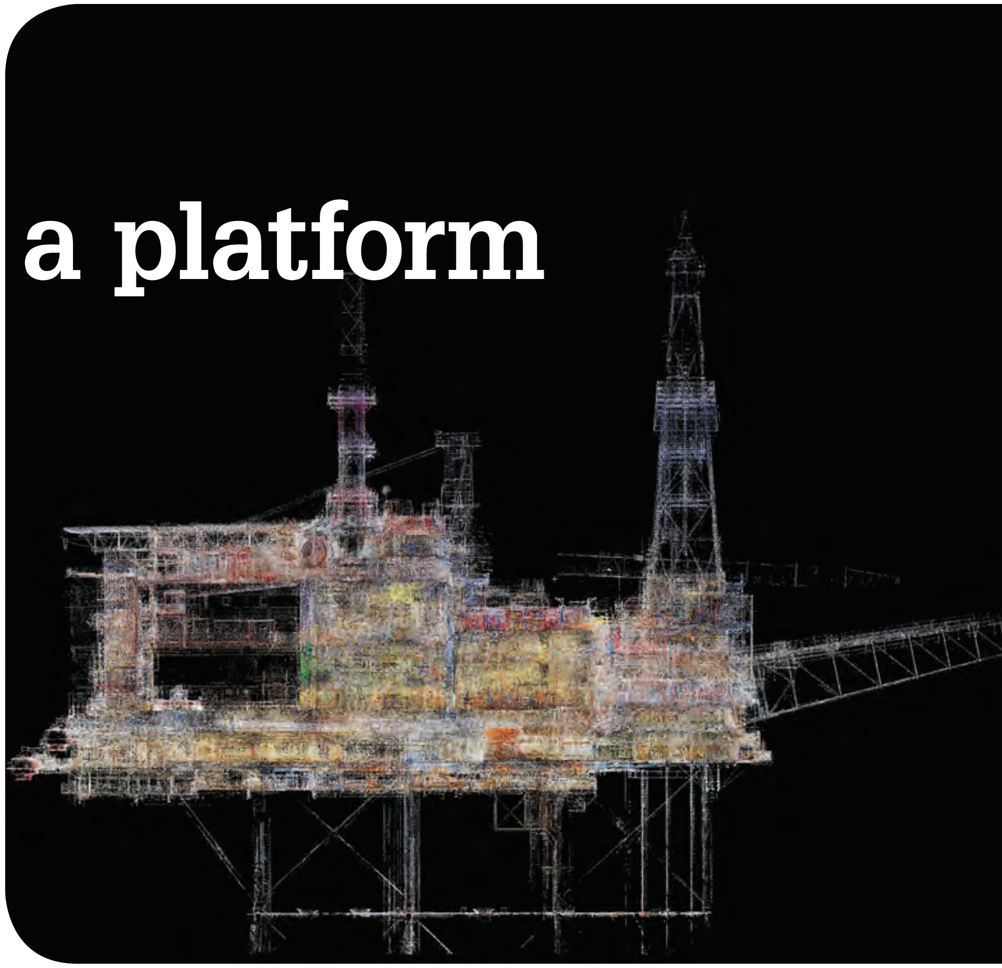
James Onifade *is a wellsite drilling supervisor with the main responsibility of ensuring a safe and efficient application of the MPD technology. Onifade earned a bachelor's degree in mechanical engineering in 2002. Onifade also holds a master's degree in mechanical engineering from the University of Portsmouth and a master's degree in oil and gas engineering from Robert Gordon University, Aberdeen.*

Mapping a platform

Laser scanning with real-time results using offshore-approved tablets is coming, say Carl Bennett and Stewart Buchanan.



Linking together data from multiple surveys to create whole platform virtual model
Images from Wood Group ODL.

Aging offshore assets, in the North Sea and elsewhere, require routine maintenance and inspection to ensure their continued integrity. Mobilizing designers and engineers offshore to view and measure equipment and structures takes up scarce bed-spaces needed by maintenance and operations personnel.

An increasingly used alternative is laser scanning, to create precise virtual models of a platform, known as point-clouds. These provide onshore engineers with the accuracy (less than 3mm across an entire platform) and detail required to design and fabricate items such as spools, vessels and skids. In turn, construction teams can install the new items safely, without encountering any clashes or failures-to-fit.

Laser scan technology has been available to the oil and gas industry for over a decade. However, in the last five years, the use of digital color photography to produce full color point-clouds has further enhanced its use. The color images assist designers, engineers, project managers, and construction coordinators, with visualizing exactly what is on the installation, and are ideal for platform familiarization, or considering design options at the start of a project.

A full facility first

In 2012, Wood Group ODL was tasked with its first whole, colored-platform scan. The platform topsides are about 12,200-tonne, comprising 27 individual modules on seven levels, giving an indication of the scale of the facility. The offshore phase of the survey required 65 days on the platform with two surveyors.

To put this in context, most surveys undertaken require 7-14 days offshore, with a single surveyor. Since the DCS team was formed about four years ago, it has undertaken surveys on 36 offshore platforms and floating production, storage and offloading vessels, and three on-shore facilities, mostly in the UK sector.

The scanning was undertaken module by module, and each set of scans were combined into one database, shown in Figure 1. For this project, the scan required 1.4 terabytes of data. Some 220GB of raw data was gathered during the survey from the total stations, laser scanners and digital photography.

How it's done

For a full platform laser scan, a survey team creates a platform control network, to enable all laser scans to be linked together into a single virtual model.

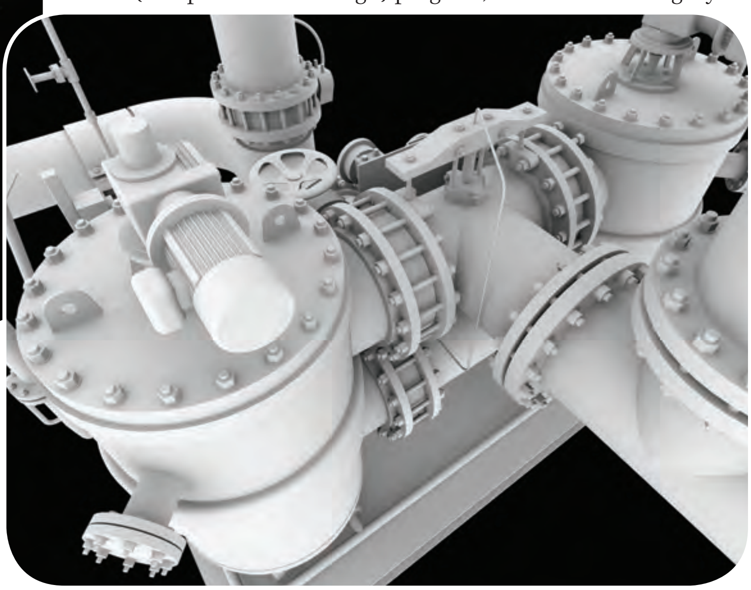
Using the control network, each surveyor performs the laser scans and panoramic color photography in locations where at least five control network targets can be seen by the laser scanner.

Leica HDS6200 instruments are currently used, with Nikon digital SLR cameras fitted with fish-eye lenses capturing color images, and a Nodal Ninja to ensure the camera is in the same aspect as the scanner. Each up to five minute scan, performed under ISO 9001:2008, covers a 360 degree floor to ceiling volume and collects some 50 million pixels, to provide measurements which will meet the tolerances required by fabricators. For a clash check within a module there will be 50 scans typically, and a scan of a platform deck will require hundreds of scans.

The raw data is processed, using Leica's Cyclone software, to create a single point cloud; a 3D display of the laser returns from the scanner in one position. The scanner is designed to ignore signals returned from beyond 80m, as the accuracy is degraded above that distance. However, during processing, the ODL dimensional control survey (DCS) team filters out all scan data beyond 15m, improving the accuracy, reducing the amount of data to be processed, and removing returns from distant spools or modules that would show up as noise.

The digital photographic imagery is processed using PTGUI software, which takes 30 images from each survey point and stitches them into a single panoramic image. From this image, six flat images are created, to show the front, both sides, behind, above and below the survey point.

The colored point clouds are then registered, using Cyclone, to ensure the data from each scan properly aligns. Finally, Leica's CloudWorx program, and a CAD (computer aided design) program, is used to apply a coordinate system to the database.



A 3D visualization developed from scan data.

Data for decommissioning

The laser scan data on the full platform scan was required to model all cut zones and separations to plan a proposed method of decommissioning. In addition, the surveyors were able to use the point-cloud to identify the nearest flanges, valves that could be disconnected without requiring cutting.

The layered CAD drawings, in conjunction with the model TruView, provide the as-built information necessary to identify and detail all systems that require cuts in each specific cut zone, allowing complete module separation.

The decommissioning study team would not have been able to complete the module separation scope to a useful level of detail if they had to rely on existing drawings and documentation. Additional offshore survey trips were not an option, due to a drilling campaign underway on the platform.

Further benefits

3D scan data can also be crucial for brownfield modifications. Most platforms in the North Sea have a plant design management system model, which provides 3D information based on the platform's design drawings. Using the point-cloud data, they can then compare their design with the as-built dimensions on the platform, which will take into account any changes made to the original design.

Colored point-cloud databases provide a source of highly accurate information, which can be shared easily between disciplines, teams, project offices and even third-parties, via web portals. Portals can be layered with data from other sources, such as maintenance plans, asset integrity data, inspection reports and images, creating an integrated system to assist duty-holders in maintaining a safe and productive asset.

Point-cloud data can also be processed to create training environments, providing operators, maintenance engineers, and construction crews with realistic training before mobilizing offshore.

More applications and easier use is coming, however. Up until recently, significant computing power has been required to handle the large terabyte-size files created. Now, laptop and desktop processing speeds and storage capacity have become sufficiently affordable to make the process cost-effective and capable of delivering survey data in an acceptable time. In the future, we could see scans from handheld devices then viewed live on offshore safe tablets.

However, there is still a place for traditional surveys using instruments known as Total Stations, for smaller jobs such as closing spools, where speed is of the essence, and for replacement of like-for-like items. For surveying larger volumes, or complex pipe-runs over several decks, laser scanning is a more efficient and effective method.

Future

The ability to process larger amounts of data faster is bringing point-cloud data to fabricators or operators more quickly. Hand-held scanners are becoming lighter and more accurate, and when linked to hand-held tablets will enable data-gathering to be carried out in near real-time.

It will not be long before it will be even more cost-effective to undertake whole-platform scans, and use hand-held scanners to provide detailed information on areas of interest, such as corrosion, signs of wear, or tie-points for new or replacement systems.

Using intrinsically safe tablets will enable the onshore and offshore teams to share information almost immediately, and for initial designs to be virtually superimposed over the actual platform structure and equipment to confirm the suitability and practicality of the design.

Laser scanning combined with digital photography is a well-established technology that is currently providing significant benefits to the oil and gas industry. As the technology matures and develops it will play a vital role in the safe and efficient operation and maintenance of oil and gas assets, both onshore and offshore. OE

***Carl Bennett** joined Production Services Network (now Wood Group PSN) in 2006 after a 20-year career in the Royal Air Force. Since joining Wood Group PSN, he has worked as a project engineer supporting a major client and was assigned to the Royal Dutch Shell Asset Integrity Process Safety Management program in the Netherlands. He holds an MBA from the Aberdeen Business School.*

***Stewart Buchanan** joined Wood Group ODL in December 2013 as Global Head of Sales and Marketing. Stewart is responsible for the development and implementation of the global sales and marketing strategy to drive ODL's business plan.*

Conversion work

Alan Thorpe recently paid a visit to Singapore's shipyards. He gives a rundown of some of the current floating production and storage unit conversions underway in Singapore and in Malaysia.

Keppel Shipyard, part of the Keppel Offshore & Marine Group, is the world's leading exponent of the FPSO/FSO conversion market.

In this market, Keppel has been involved is some 119 such projects since 1981. This year alone Keppel has delivered four FPSO/FSO conversion projects and had another two due for delivery before the end of 2014 - the 107,000-dwt *Armada Sterling 11* for Bumi Armada Berhad, and the 94,225-dwt *Ratu Nusantara* for M3nergy Offshore.

There are also three further FPSO projects currently underway at Keppel Shipyard – the 128,829-dwt *Bertam* for Lundin Services, to be stationed offshore Malaysia, the 159,000-dwt *Turritella* for SBM Offshore, to be stationed in the Stones Field offshore Australia for Shell, and the 166,468-dwt *Kraken*, for Bumi Armada Berhad, for the Kraken field in the UK sector of the North Sea. Keppel is also involved in the extensive refurbishment of an existing FPSO – Apache Energy's 101,832-dwt *Ningaloo Vision*, which will go to the Van Gogh Filed in the Exmouth Basin, offshore Australia.

The long-term FSO conversion project for Mobil Cepu, the *Gagak Rimang*, was completed during September 2014 and has now left Sembawang Shipyard, part of Sembcorp Marine, for her station offshore Indonesia on the Banyu Urip field in the Cepu oil block in East Java for Exxon/Mobil.

Sembawang Shipyard was responsible for the full engineering, procurement and commissioning (EPC) contract involving this project. The vessel is able to contain 1.7 MMbbl and it will be hooked to a mooring tower on the bottom of the sea. If, next year, Banyu Urip field produces 165,000 bbl/hr, the vessel is ready to store the production of 10 days.

The *Navion Norvegia* in Semcorp Marine's new SIY yard. Photo by Alan Thorpe.

The first of the Euronav VLCCs arrive at Sembawang for conversion into FPSOs for Total's Kaombo project offshore Angola. Photo by Alan Thorpe.

Meanwhile, the first of the two Euronav very large crude carriers (VLCCs) has arrived at the yard for conversion to FPSOs for Total/Saipem. The two vessels will be in the yard for 32 months total, the FPSO conversion work lasting some 28 months for each vessel, the second vessel due in the yard within the next few weeks. The first vessel, the VLCC Olympia has arrived and her sistership, *Antarctica*, will arrive before the end of the year.

The two sisterships will be converted into two turret-moored FPSOs for the Kaombo project, approximately 150km offshore Angola. The major work will include refurbishment of the VLCCs, construction engineering, the fabrication of flare, helideck, upper turret and access structure, integration of the topsides modules (which will be fabricated at Saipem's Indonesian

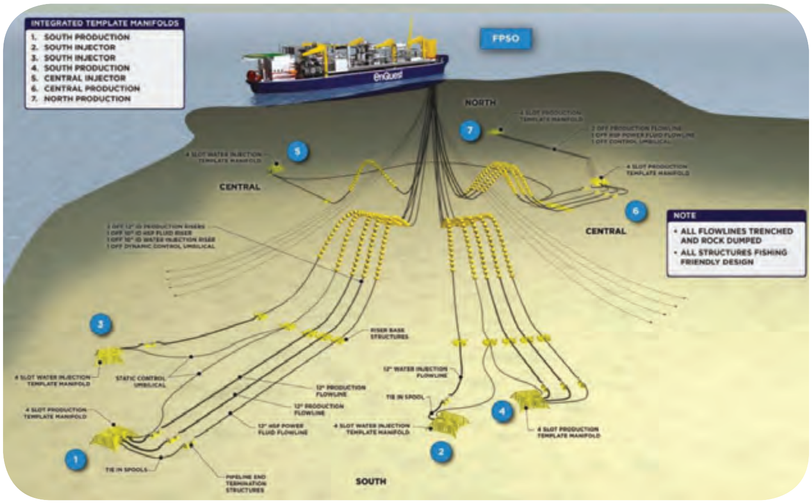
yard) and lower turret components, and pre-commissioning of the FPSOs. The two converted FPSO units, owned by France's Total and operated by Italy's Saipem, will each have an oil treating capacity of 115,000 b/d, a water injection capacity of 200,000 b/d, a 100 MMscf/d gas compression capacity and a storage capacity of 1.7 MMbo.

One of the most recently-won projects at Jurong Shipyard, also part of Sembcorp Marine, likely to take two years, involves the conversion of Teekay's 130,596-dwt shuttle tanker *Navion Norvegia* into an FPSO to work in ultra-deep waters in Brazil's Santos Basin. This conversion, although a Jurong contract, is actually being undertaken at Sembcorp Marine's new Sembmarine Integrated Yard at Tuas (SIY), which opened during 2013 (*OE*: October 2013). Currently the yard comprises four large graving docks, all of which can accommodate ships up to VLCC/ULCC (ultra large crude carrier) size. The *Navion Norvegia* will be the first conversion to be carried out this yard.

The contract, placed by OOGTK Libra GmbH & Co KG, a joint venture between Brazil's Odebrecht Oil & Gas and Teekay Offshore, is worth US$696 million. Work will include detailed engineering, installation and integration of topside modules, installation of external turret and power generation, accommodation upgrading as well as extensive piping and electrical cabling works.

Scheduled for completion 3Q 2016, the FPSO will have the capacity to produce 50,000 b/d and 4 MMcm/d of natural gas, and is expected to be chartered to Petrobras for work on the Libra field in the ultra-deepwater section of Brazil's Santos Basin. Operating as an early well-test unit, the FPSO will be on a 12-year charter once it begins its contract in late 2016.

The FPSO unit is expected to be owned and operated by the joint venture company and will service on the Libra pre-salt field in the Santos Basin offshore Brazil, which is expected to start operations in late 2016. The block covers approximately 1550sq km in around



The Kraken FPSO will sit offshore the UK in the North Sea. Image from EnQuest.

The Shell Stones project in Keppel. Photo by Alan Thorpe.

2000m water depth (6500ft). The reservoir depth is around 3500m (11,500ft). Brazil's ANP has estimated that total gross peak oil production could reach 1.4 MMb/d.

Finland's Deltamarin has won the contract with Jurong Shipyard for the basic engineering of the *Libra* FPSO. The contract guarantees the continuation of Deltamarin's involvement in the Libra project as the company has earlier participated in the outline phase design of the unit. "We are very happy to be a part of this fast track FPSO project and we strongly believe it will be a success for all parties. This contract shows the market's strong belief in Deltamarin's ability to perform in technically complex fast track offshore engineering projects," says Deltamarin's Offshore Director Oskari Jaakkola.

Meanwhile, the VLCC conversion at Jurong's Tanjung Kling facility brings Jurong's tally to 22 conversion projects for MODEC. This project, involving conversion of the 300,955-dwt VLCC *Centennial J*, is scheduled for completion by 4Q 2015 whereupon the FPSO will be deployed on the TEN project in Ghana. MODEC will operate the unit on behalf of Tullow subsidiary Tullow Ghana.

The unit will have capacity to produce and treat 80,000 b/d crude, 65,000 b/d of produced water and 180 MMscf gas. The unit, which will host several subsea tiebacks from three reservoirs, will also be capable of storing 1.7 MMbo. The fields lie in water depths of 1-2000m and the FPSO will be about 25km from the Jubilee field, operated by Tullow.

Malaysia's Malaysia Marine & Heavy Engineering (MMHE), Pasir Gudang, part of the MBO Group, has won two contracts for long term conversions, the first involving a tanker to a FSU and the second from a drilling rig to a mobile offshore production unit (MOPU).

The first contract involves EA Technique's 47,172-dwt, 1996-built tanker *Fois Nautica Tembikai*, which will be converted by MMHE to a FSU for a charter with Petronas for service offshore Malaysia. This the second similar conversion carried out by MMHE for this owner, the Nautica Maua, having been completed in 2013.

The second new contract involves Coastal Energy's jackup rig EP 7, formerly Hercules 250, which will be converted to a MOPU over the coming months. This is the third similar conversion carried out by MMHE for this rig owner over the past few years. The yard is also carrying out a similar conversion involving the jackup rig Rubicon.

The final stages of a major subsea

***Surf Supporter* in Batamec** Photo by Alan Thorpe.

Shell's Stones FPSO, an artists' impression. Image from SBM Offshore.

construction conversion project will also soon be completed at Batamec, part of Otto Marine, located on the Indonesian Island of Batam. The project involves the 4863-grt offshore subsea construction vessel *Surf Supporter*, which is being extensively modified for a contract with Fugro in Australia. She is owned by Australia's RY Offshore, and managed by Australia's Go Offshore, Perth. She was built in India's Magazon Dock, Mumbai during 2012 and has been sailing as the Go Surf until this year, when she arrived in Batamec during September.

Work to be carried out by Batamec includes the installation of a deck crane, and accompanying modules, a 15-tonne heli-deck and side sponson tanks and extensive changes to the accommodation. She was due to leave Batam during November.

During 2014, Singapore's PaxOcean has carried out a number of major conversion projects, one of the most complicated being the conversion from offshore supply vessel to a specialized diving support vessel of the *Maridive 603*. This project was a fast track project, the vessel redelivered in June. Apart from all the upgrade equipment, the vessel also had her accommodation increased. The yard also carried out a conversion of the *Greatship Ragini* from platform supply vessel to a survey, derrick and geotechnical vessel. This vessel was redelivered during July. **OE**

Out of sight, Out of mind

Peter Beales discusses the dangers of neglecting software integrity

What constitutes an "asset" in the oil and gas industry? The obvious spring to mind: vessels, pipelines, and generators, for example. Few of us, however, would immediately think of invisible assets, like the software code, files and data stored in tiny silicon chips. Yet, without that information, the entire industry could collapse.

The need to protect physical assets is clear. However, with electronic information, it's usually out of sight, out of mind.

A recent study found that an astonishing 90% of UK production companies lack secure systems to protect all of their process control software. Yet, Britain is hardly an anomaly; this neglect is worldwide.

Software is fundamental to production processes, product quality and safety. To minimize the effects of process system failure, operators must protect the integrity of their process control system software. This necessity is manifested in four key areas: security, disaster recovery, change management and compliance.

Security

Cyber threats are constantly in the news, yet oil and gas operators have been slow to recognize the risks to their process control systems. While external infiltration from hackers or malware is undoubtedly a problem, insiders who have access to process control software perpetrate nearly half of security incidents. Granted, some of these breaches are innocent and accidental, but in too many cases employees, subcontractors or third parties deliberately infiltrate systems to steal data or sabotage a system.

The *Global State of Information Security Survey 2014* revealed that,

compared with 2013, organizations reporting financial hits of $20 million or more increased 92%, and financial losses caused by security breaches jumped 34%. Losses are not exclusively monetary. Respondents also expressed concern about theft of intellectual property, damage to company reputation and declining share value. These concerns demonstrate the imperative need for stricter control over access to critical systems.

Disaster recovery

Every operator understands the immense cost associated with unplanned shutdowns. Few, however, stop to think about how important software is to the running of a system. When something goes wrong with process control software, costly delays are often prolonged because of the company's reliance on ineffective back-up solutions for dealing with the problem. Panic ensues. Where are the backup disks? Do we have the correct version of software? How do we know the software isn't obsolete?

Backup software can often be corrupted. Or it can be misplaced. Or it might not exist. Software essential to the smooth running of remote assets might be stored hundreds of miles away. Yet when it fails, so does the asset. In an industry renowned for disaster preparedness, this particular form of potential failure is often neglected. The best time to buy insurance is *before* a fire.

Change management

In Asset Guardian Solutions' (AGSL) experience, many corporate MOC management systems are ill-suited to managing changes to process control software configuration code. An area where problems occur is "Parallel Software Changes," when alterations to software configurations are made simultaneously by different parts of the organization, resulting in multiple versions of a single piece of software. The resultant damage can be time-consuming and expensive and, at worst, threaten installation safety.

The solution is to implement an integrated management of change process, designed specifically for software configuration code. To avoid Parallel Software Changes, the system adopted should, as a minimum, include software "check in – check out" capability.

Compliance

The offshore industry is obliged to comply with a myriad of regulations, standards and codes of practice, requiring the effective management of process control software, information security and data management. To comply with these, companies must provide evidence of secure backups of codes and documents, configuration management systems, password administration, and audit trails.

Take control and control change

These four risks demonstrate that the integrity of 'hidden' assets is just as important as that of physical assets.

No company would ever think of neglecting the physical infrastructure or security of an FPSO, drilling rig or pipeline. Why, then, are so many prepared to ignore the costly and dangerous problems that can easily result when process control systems are left unprotected? OE

Compared with 2013, organizations reporting financial hits of $20 million or more increased 92%, and financial losses caused by security breaches jumped 34%.

Peter Beales is business development manager for Asset Guardian Solutions Ltd. He is responsible for the sales and marketing of the company's range of "Configuration Change Management" software tools that serve the global oil and gas, marine and utilities industries. An electrical and instrumentation engineer with over 30 years in the instrument and control sector, Beales has held a number of senior management positions with ABB, TYCO, IMES Engineering Services, and 3Sun Control and Instrumentation.

Aegir's first project

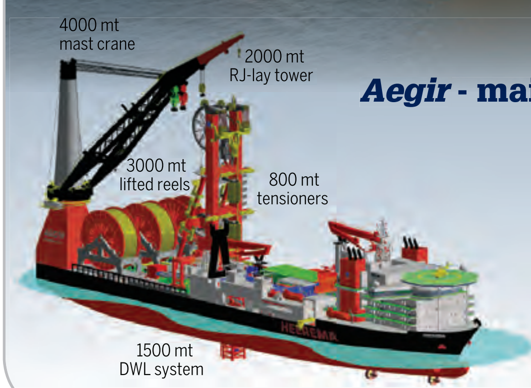
Heerema Marine Contractor's new multi-purpose construction vessel *Aegir* completed its first job in the Gulf of Mexico. Meg Chesshyre reports.

The first mobilization for Heerema Marine Contractor's newbuild multi-purpose deepwater construction vessel *Aegir* was for the subsea part of Anadarko's Lucius Spar project in the Gulf of Mexico, which was completed early in 2014.

The job was awarded before the vessel was even built, as Meredith Taylor, senior project engineer with Heerema Marine Contractors (HMC), based in Houston, explained at the International Marine Contractors Association's recent annual seminar in London.

The decision to build a new vessel was taken because Heerema, as a key player in complex deepwater construction for over 10 years, wanted to maintain and expand its position in the expected growth of the market in complex high-tech field developments.

A mix of high-end capabilities were chosen for the new vessel, including heavy pipelay to 2000-tonne top tension and 3500-mwd, heavy lifting to 4000-tonne capacity using a mast crane, heavy reeling to 800-tonne top tension,



Aegir - main equipment

Length o.a.	211.5 m
Width	46.2 m
Depth	16.1 m
Draft (working)	9–11m
Draft (transit)	8 m
Installed power	48 MW
Dynamic positioning	DP3
Transit speed	12 knots
Accommodation	289 POB

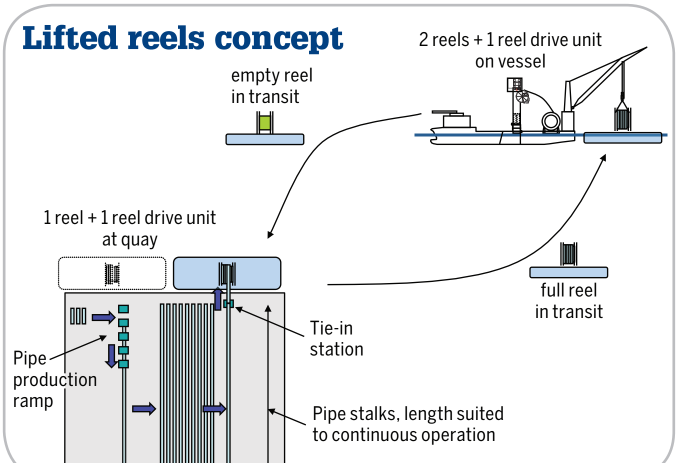
plus lifted reels and the use of a pipelay abandon or recover system for deepwater lowering. The pipelay tower is called an R J tower by HMC, because it can perform reel-lay and J-lay, by using different ways to hold the pipe – friction clamps and hang off collars.

The lifted reels concept meant that the vessel could stay on the field with the reels being brought from shore. The width of the vessel (46.2m) meant that it was possible to put three reels across at a time.

HMC also wanted to make the new vessel, named after a Norse god of the sea who ruled the waves, back to back compatible with its existing deepwater construction vessel the *Balder*. A monohull was selected for good transit speed (12 knots) for worldwide operations and good workability in the long swells found offshore West Africa and Brazil. It was based on an existing vessel design, a customized Ulstein Sea of Solutions SOC 5000, to speed up the payback time.

"We decided to build the *Aegir* in 2010," Taylor says. "We were negotiating the (Anadarko Lucius) contract in 2011. At the start of 2012 the contract was awarded just after we had laid the keel, so we were having to do analysis and design procedures based on equipment that hadn't yet been fabricated or installed. We had to set up the offshore spooling yard before the vessel had arrived in Rotterdam (for installation of the pipelay equipment by Huisman)."

Lifted reels concept



Images from Heerema Marine Contractors.

Once the pipelay equipment was on board, the vessel sailed to the Gulf of Mexico for some trials then started straight away on the Lucius project. It emerged during the trials that the weight of the reel and the exact height of the crane resulted in a pendulum effect. The natural frequency of the pendulum exactly matched the vessel's response to the long swell. The solution was a dampened tugger system. This gave a change in damping according to the velocity of the pendulum. Interestingly, "not only did it damp the motion of the reel, but it also damped out the whole system, so the vessel stopped rolling as well."

The Lucius project comprised the subsea tieback of six wells in a water depth of 7100ft. The *Aegir*'s scope of work consisted of four 8in., three 6in. flowlines, six 8in. SCRs (steel catenary risers), a 140-tonne manifold and a crossing mattress. Heerema's DCV *Balder* installed the suction piles, the SPAR mooring and another manifold, and the DCV *Thialf* installed the topsides.

The pipelay required the use of four reels. The heaviest one weighed 2754-tonne in total, including the reel and rigging. The pipe weight was 1646-tonne. The weather was good, with a significant wave height of only 1.4m for the first reel for a short period, the other sea states being lower. This meant it wasn't possible to test the system to its limits.

Computational fluid dynamics analysis was used to model hydrodynamic loads. A radar wave measurement system in the moonpool allowed for the monitoring of the waves compared with those outside. Steering winches added as a result of the analysis gave extra control and damped out some of the pipeline end termination movements during the lowering.

The moonpool was also used to lower the 140-tonne manifold down to 6820ft using the deepwater lowering system, having been handed over from the crane using a 45m synthetic sling. The system was designed to operate in up to 3m sea states, but once again the weather was perfect. "It was like a millpond when we installed it," Taylor says.

In mid-October 2014, the *Aegir* started on a contract transporting and installing infield flowlines, subsea structures and moorings for the INPEX's Ichthys LNG project, on a sub-contract from McDermott Australia. HMC also has a contract for the *Aegir* for the installation of the Shell Malikai tension leg platform in Malaysia. OE

Coming attraction

EMAS AMC's flagship vessel, the *Lewek Constellation*, is close to completion at Huisman's yard in Schiedam, Netherlands.

The latest addition to EMAS AMC's fleet has been designed for rigid and flexible pipelay and construction work in water depths exceeding 3000m. The vessel is an ice classed, DP3, multi-lay vessel with heavy lift capabilities.

The vessel, built with a 3000-tonne heavy lift mast crane at Singapore headquartered Triyard's Vietnamese yard, Saigon Offshore Fabrication & Engineering (SOFEL), completed its first job, ahead of arriving at Schiedam, for VAALCO Gabon (Etame), offshore Gabon.

The work scope for VAALCO included the transportation and installation of two jackets, topsides, flare booms and living quarters for the Etame and Southeast Etame / North Tchibala (SEENT) platforms, along with the installation of a new living quarters and a gas lift package onto the FPSO *Nautipa*.

Once its multi-lay tower and ancillary equipment for pipe lay activities are installed, the vessel is due to proceed to the US Gulf of Mexico to work on Noble Energy's Gunflint project in 1Q 2015, installing pipelines, umbilicals and ancillary equipment.

EMAS Marine Base in Ingleside, Texas, will be used to perform the pipe stalking and fabrication of various subsea structures.

Gunflint was discovered in 2008, and is estimated to contain resources between 65-90 MMboe. The field is in Mississippi Canyon Block 948, at a water depth of 2000m.

The 178m-long, 46m-beam *Lewek Constellation*'s multi-lay system (MLS) comprises an 800-tonne tiltable tower, a 60-tonne pipeline end termination (PLET) handling system for large PLETs, and a 1200-tonne abandon and recovery (A&R) system. The tower has dual 400-tonne tensioners, a straighter for handling pipe-in-pipe flowline systems with outer pipe up to 16in. outer diameter (OD), a 900-tonne hang-off module (HOM), and a movable/adjustable work platform along the tower. The tower can be adjusted from 60° to 90° to accommodate pipe laying from shallow water to ultra-deepwater. The A&R system has two 600-tonne traction winches and a 125-tonne secondary winch.

In rigid reel lay, the vessel can apply up to 800-tonne of dynamic top tension on flowlines and rigid risers up to 16in. nominal outer diameter (OD). In flexible mode, the vessel and lay system can accommodate sizes up to 24in. nominal OD, while applying 400-tonne and 430-tonne of top tension, respectively.

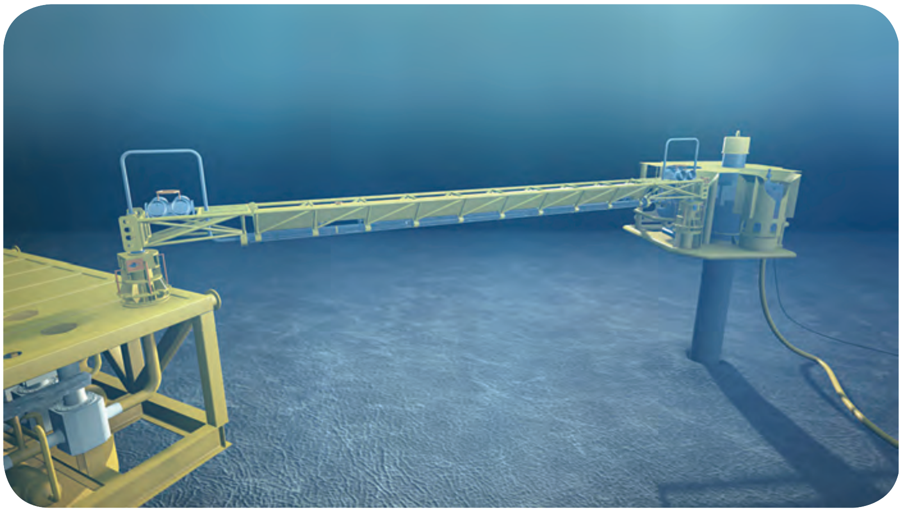
Spooling barge

The pipelay vessel (pictured, photo from EMAS) will use a spooling barge, outfitted with a spooling system that includes a fleeting roller track assembly, a fleeting tensioner, a reel cradle assembly and winches, for reloading reels. Pipe will be spooled on to the reels on the barge at a quayside, then taken offshore for reel transfer. The vessel's heavy-lift system is used to offload empty reels and load full reels.

The vessel, which accommodates up to 239 personnel, can store up to four rigid pipe reels and up to two flexibles carousels.

Alliance creates results

Two years in the making, Aker Solutions and Baker Hughes' subsea production alliance is already proving fruitful. Elaine Maslin reports.



The Baker Hughes/Aker Solutions POWERJump flowline booster.
Image from Aker Solutions.

When Aker Solutions and Baker Hughes joined forces under an alliance last year it was with a mission to develop technology for production solutions designed to boost output, increase recovery rates, and reduce costs for subsea fields by drawing on each other's expertise.

One of the key targets is boosting production from mature fields. By 2020, more than half the wells installed on the Norwegian and UK Continental Shelves will be more than 10 years old.

"This is going to grow," says Herve Valla, head of research and innovation and technology strategy, Aker Solutions. "The number of wells more than 11 years old will grow from 800 to 1450 between 2012 and 2020. The number older than 21 years will grow from 86 to 649 (in the same period). There will be a need for more advanced subsea production, but also a more simplified boosting solution."

The first new product aimed at boosting has already been unveiled by the alliance. "Up to now seabed boosting has been using larger pumps, typically offshore west Africa with 150,000b/d floating production systems," says Ian Ayling, Director of Business Development and Sales, Baker Hughes. "For the smaller fields, there hasn't been any cost efficient tools on the boosting side. We have seen some innovation here and there, but, so far, for small individual wells, at 30,000 b/d, there haven't been any good tools. Our engineers came up with the POWERJump flowline booster, which uses existing field infrastructure."

POWERJump is a boosting system which can be added between the wellhead and manifold. The concept would see a Baker Hughes' electrical submersible pump placed inside the jumper that connects the Xmas tree and the manifold. "It is relatively small, relatively flexible and uses the existing infrastructure. It would be possible to install with small vessels and offers 80-90-day pay back," says Ayling.

Ian Ayling

Aker Solutions describes the technology as an "innovative repackaging of existing, field proven technologies" into a solution for these lower flow rate applications. The concept is suited to brownfield developments where it can use existing subsea infrastructure to provide additional boosting on depleted wells, adding incremental production or potentially deferring plug and abandonment. The POWERJump will also have application in greenfield sites as a solution for producing stranded reserves back to a host facility or seabed injection, Aker Solutions says.

"We looked at how many fields could use this idea and it came to a very large number, which surprised us. These fields are everywhere because they are the longer step outs or where the production is below a certain threshold. Neither Aker Solutions nor Baker Hughes could have come up with this idea on their own," says Ayling.

More broadly, the alliance's initial focus will be well performance, boosting, power and control, combined integrated control and power systems, and seabed boosting.

"We are going deeper, into more remote and harsher environments," says Ayling. "Whether that is metocean challenges in the Arctic or sub-surface challenges with high-pressure, high-temperature, or more complex reservoirs, or a combination of these. With, in the short-term, industry not finding more (fewer exploration successes), cost efficient solutions for increasing or sustaining production and a longer-term goal of improved recovery is why the two companies came together."

Talks started between Baker Hughes and Aker Solutions about two years ago, says Ayling. "We are convinced the only way to meet this challenge head on is collaboration across traditional industry segments and boundaries. Combining Baker Hughes' artificial lift and completion technologies with Aker Solutions' subsea production systems, coupled with joint knowledge in subsea intervention, you can provide a horizontally integrated service… from the reservoir through the interface of the Xmas tree to production facilities."

For Valla, the whole system needs to be addressed. Well access for easier intervention operations needs to be by design. For enhanced oil recovery, boosting, and processing, integrated power and control systems are needed, he says. OE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Two tensioners from Aquatic's existing fleet being loaded out for offshore mobilization.
Photo from Aquatic.

Tension in the deep

Aquatic Engineering & Construction is due to launch a new 120-tonne tensioner in 2015. David Tibbetts, VP Technology, spoke with OE about the methodology behind its design.

When late in 2013, Aquatic was approached by a major oil and gas contractor looking for a tensioner for a future project, it prompted Aquatic to take a look at the market. The result is a new 120-tonne modular tensioner.

The main driver is the move into deeper and deeper waters. According to Douglas Westwood's deepwater forecast, 2014-2018, deepwater expenditure is expected to increase by 130%, compared to the preceding five-year period, totaling US$260 billion.

The move into deepwater has been driven by a maturation in mature basins onshore and shallow water declines.

There are already established deep water plays, offshore Brazil, the Gulf of Mexico and West Africa – the "Golden Triangle" – and other areas are emerging, such as East Africa.

This means that the flowline handling equipment is having to increase in capacity to meet the higher loads seen in deep water. The contractor who approached Aquatic had asked for a 100-tonne capacity in 1000m-deep water tensioner.

Aquatic decided to research what was already available on the market and what might be required. It found that there was a requirement for tensioners above 100-tonne in more than one region worldwide, including the Golden Triangle.

"Our market research found that tensioner requirements are rising, but the largest portable tensioner available is currently at 75-tonne," says David Tibbetts, VP Technology at Aquatic, an Acteon company.

Because of the increase in size a larger tensioner would involve, the research suggested a vertically mounded single tensioner would help save desk space, as well as handle the product better. Adding a dual-mode configuration would also enable 2000m water depths to be reached, at least with an umbilical.

But, the research also raised a question, says Tibbetts. This was: "Why this size tensioner and not something even larger, such as perhaps a 550te tensioner for use in waters off Brazil?"

David Tibbetts

"The answer for us currently, is that a tensioner of that size would normally be integrated into the structure of a vessel, and this requirement currently exceeds the Aquatic unique selling point of ease of transportation and mobilization; we send our equipment to boats, rather than requiring customers to send their boats to our equipment.

Modular 120-tonne 4-track tensioner dimensions and weight

Length	9.6m
Product and contact length	7.1m
Weight	85-tonne
Width	3.42m
Height	3.5m closed position 5.3m open position
Line pull	Up to 120-tonne in single mode Up to 200-tonne in dual mode

"As a business, we took a realistic and commercial view on the capability of this tensioner [the 120-tonne tensioner]. It's a step change from where we are currently and it gives us a guaranteed capacity beyond our dual tensioner solution."

The tensioner design has a four-track configuration but can also be operated in two-track mode if required i.e., the industry standard. "The co-efficient of friction engineers expect is 0.09 and so we work on the assumption that the industry norms will be used within any new piece of equipment," says Tibbetts. However, other options were assessed, such as a three-track model, which can offer greater accessibility for the product.

Tibbetts says Aquatic applied whole life design principles to the design – incorporating operational expertise into the design so that you are minimizing the forces necessary to deploy the product; retaining the integrity of the product and enhancing the efficiency of the installation process, says Tibbetts. The result will be on the market this year. OE

25 years in the planning

A unique and long-awaited sight arrived at one of Europe's busiest ports early January - Allseas' 382m-long, 124m-wide platform installation/decommissioning and pipelay mega-vessel *Pieter Schelte*.

The giant €2.4billion, twin-hull vessel left ship builder Daewoo Shipbuilding and Marine Engineering's Okpo shipyard in South Korea 17 November, after four years' construction, stopping by Singapore and Cape Town.

The vessel, which entered the Rotterdam harbor on her own propulsion, is due to be moored at a rented deepwater site at Rotterdam's new Maasvlakte in order to have a topsides lift-system beams installed on the bows.

Test lifts with the system will then be carried out on a test platform in the Southern North Sea, which Allseas is building, after which the vessel is due to remove the Talisman Yme platform topsides, in summer 2015.

The removal of the Shell Brent Delta platform is planned later in the summer of 2015, or in the spring of 2016. The vessel was also lined up for a pipelay job on the South Stream offshore pipeline section, but the project was put on hold by Russian president Vladimir Putin 1 December, citing European Union opposition.

The *Pieter Schelte*, the brainchild of Allseas founder Edward Heerema, has been 25 years in the planning. The vessel was designed to make a significant impact on the heavy lift capability currently available in the global offshore market, both for platform installation and decommissioning; and pipelay with its 2000-tonne (2205 short tons) tension capacity S-Lay pipelay package.

Its lift capability is given as an eye-watering 48,000-tonne (53,000 short tons) for topsides and 25,000-tonne (27,500 short tons) for jackets.

But, Allseas also sees a market for an even larger vessel. Speaking last year, Edward Heerema told OE that the interest in the vessel [*Pieter Schelte*] and its potential has been enough to lead Allseas to consider building a second single-lift vessel that will exceed even the Pieter Schelte's 48,000-tonne topside lifting capacity, by 50%, to 72,000-tonne. OE

Pieter Schelte facts:

- Dimensions: 382m-long and 124m-wide, with a 59-wide slot for removing topsides.
- Lift capability: 48,000-tonne for topsides using eight sets of horizontal lifting beams, at 6000-tonne a piece, across the slot for removal or installation of topsides.
- 25,000-tonne for jackets, using two tilting lift beams on the stern for lifting and laydown
- Pipelay system: A 2000-tonne capacity S-Lay pipelay system, able to handle 24m pipe sections (double joints) under tension using four 500-tonne tensioners, with a 170m-long stinger.
- Power: 12 thrusters at 75-tonne a piece, powered by eight main diesel generators, providing a total installed 95MW power
- Yard: Daewoo Shipbuilding and Marine Engineering

Image from KOTUG/Van der Kloet.

– Allseas' *Pieter Schelte* arrives

KOTUG tugs *RT Magic* and *RT Spirit* assist the *Pieter Schelte* to her berthing place in the Rotterdam Alexiahaven.
Image from KOTUG/Van der Kloet.

With oil prices depressed, Greg Hale argues that automation could make a much needed difference in the offshore industry.

Rescue mission

The scenario is set and it is time for everything to play out: automation can come to the rescue of the offshore oil and gas industry.

With crude prices at lows not seen for almost six years, there is a way to recoup costs and convert losses, or declining profits, into stronger gains and that is through a strong automation program. Through a relatively small investment and a strong and smart implementation across the board, an automation program will reap huge dividends.

Even the US Energy Information Administration (EIA) foreshadowed ominous issues confronting the industry in its *Annual Energy Outlook AEO2014:* "Among the most uncertain aspects are the potential effects of alternative resource and technology assumptions on the global market for liquid fuels, which is highly integrated. Regardless of how much the US reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices set in global markets for crude oil and petroleum products. Strategic choices made by leading oil-exporting countries could result in US price and quantity changes."

As it turned out, oil exporting countries made their strategic choices and the end result to date has been lower prices and potentially declining profit margins.

Just look at the UK. In the UK, thousands of jobs in the offshore oil and gas industry are at risk with full-year output for the entire North Sea expected to decline to 840,000 b/d, its lowest level since 1977. Billions of dollars of investment will need to come into play to pull out the remaining reserves. Industry consultancy, Wood Mackenzie, said 32 potential European oilfield developments that could produce 4.9 billion bo may end up on the back burner if prices consistently stay below US$60 per barrel,

Restoring production efficiency

A three phase asset management strategy could help counter costs, says ABB's Will Leonard.

In mid-December, the price of oil fell further after the International Energy Agency (IEA) forecast weaker demand in 2015. Brent crude fell to around US$60 a barrel, its lowest price since July 2009. Meanwhile, US crude was down even lower, its weakest since May 2009.

On top of that, IEA cut its forecast for global oil demand growth next year by 900,000 bo/d -- 230,000 bo/d less than the prior month's expectations -- to 93.3 MMbo/s, on the expectation of lower fuel consumption in Russia and other oil-exporting countries.

There is hope. According to a report from professional services firm PwC, found falling oil prices, declining production and the rising costs of decommissioning could end up tackled by operators by making 40% efficiency savings over the next five years.

But, says the report, a "back-to-basics" approach is needed to address "unsustainable" capital expenditure and operating costs, not a short-term "knee-jerk reaction."

"By better understanding the issues of performance, risks, resource etc., and sharing this knowledge internally and externally we can start to deliver a long-term cost reduction program for the North Sea which reduces capital and operational costs while maximizing resource extraction. We need to move away from the short-term approach of reducing headcount and overheads, and start to embed cost-reduction principles into all parts of the industry."

That is where automation comes into play. Some $18 billion/yr is lost purely through poor production techniques, such as badly structured maintenance on aging infrastructure, skills shortage and over-runs in turnarounds. The biggest contributor to production efficiency decline – 46% – is unplanned downtime. A lack of long-term strategic approach to asset life is clearly starting to take its toll.

Three-phase approach

One idea to increase performance is to implement a three-phase program to help restore production efficiency.

Phase 1 starts with a high level overview where a provider can come in and analyze and assess the asset life strategy

Asset management strategies could counter costs. Photos from ABB.

which is where it is hovering right now. Along those lines, BP already cut $1 billion from its capital expenditure plans.

This is where automation comes into play. Yes, new-age technologies are seeing action on the platforms, but a more involved program from drilling to producing, compliance, regulations, safety and security will allow for a more enhanced and productive enterprise. It only makes sense. Whether the price for crude increases or declines, for producers to realize a highly successful operation, they need to integrate all their technologies into one interconnected portfolio.

Neil McCulloch, president North Sea, EnQuest, speaking at a production optimization event in Aberdeen in November buttressed that point when he said production in his neck of the woods is falling woefully short.

"We have to be simultaneously shocked, embarrassed and depressed that we [as an industry] are missing our production targets. We, as an industry miss targets by a third. We are only producing 66% of what we say or tell management we are going to produce (*OE*: December 2014)."

"We believe that high production efficiency is no accident," McCulloch said. "Part of it is capital investment. We invest and see the results. It is also a relentless focus on things such as production efficiency and asset integrity."

It ends up being about doing more with less. Through better visualization and control of processes and the integration of various subsystems and electrical, fire and gas and safety and subsea control, it allows operators to quickly make a change to solve a problem and keep everything running full steam ahead.

Through an interconnected set of systems, it is possible to see what is truly going on with all aspects of the operation.

It can not only provide essential business information, it can allow for total asset optimization to ensure smarter business decisions to create a stronger profit stream.

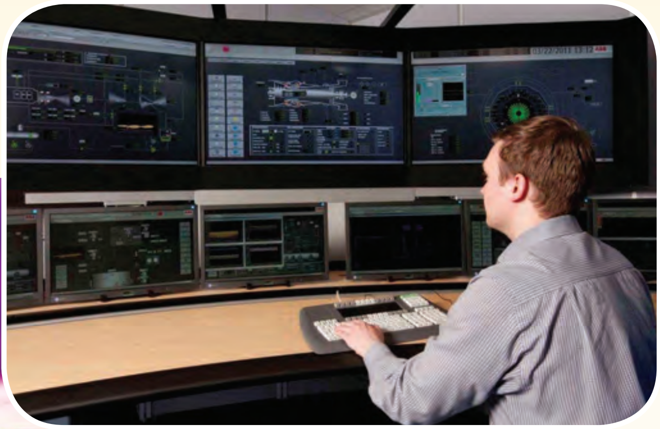
It is no secret, the industry needs to stop talking and start doing something different. Automation will be a difference maker. **OE**

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

of the platform, which can provide clarity on what the producer can achieve. While assessing the impact on operational reliability, consideration goes out to the condition/health of existing equipment, as well as operating and maintenance procedures.

Phase 2 identifies actions that will reduce equipment downtime. Using the asset life plans developed in phase 1, everything from the existing applications and people competency through to installed products and systems and lifecycle services end up examined to discover the options available for improving production efficiency.

Phase 3 implements the improvement projects identified in phase 2. It eliminates defects before they have an impact on production. Continuous feedback ends up being a priority to ensure a higher level of performance. Services for any products or systems that need installation and commissioning, maintenance, replacement, upgrade or retrofit are a part of this phase.



Reducing manning levels

Estimates show that every person working offshore costs an operator about $1.5 million/yr, when all training, safety, and wage costs come into consideration. And much of that labor ends up working on maintenance to keep the platform running.

For operators with multiple facilities or platforms, it may be possible to centralize the control system such that it controls the process across several platforms. Alternatively for single or multiple assets, providing a remote support center onshore that supervises offshore assets helps address the shortage of highly skilled experts by allowing them to work across the platforms.

This can work for platforms operating as a hub, where several connected platforms feed production through a central facility. Many of these aging hubs, even if their own production life is on the back end, could benefit by updating automation and electrical equipment to retain the production capability and asset life of the entire network.

Asset management strategies

Electrical, instrumentation, control and telecoms systems are becoming more complex as technology evolves. Their performance and operational availability remain critical for production consistency.

Yet over time, the condition and performance of this technology will degrade, which can have a negative impact on production. Asset management strategies aim to counter this impact by systematic condition monitoring of equipment, helping to avoid unplanned production downtime and reduce operational expenses by optimizing maintenance planning. **OE**

***Will Leonard** is the Head of Marketing for ABB's Chemical, Oil and Gas business in the UK & Caspian region. Leonard has a dual honors degree in Business and Law at Keele University. He has worked in the industry for the past 10 years.*

Offshore East Africa: what's next?

As a result of recent offshore successes in Mozambique and Tanzania, the entire East Africa margin currently has the attention of the world's new ventures teams, explorers and gas (LNG) buyers. What might happen next in this new hydrocarbon province? Jeremy Berry explains.

Deepwater sands of Tertiary and Cretaceous ages, related to the Rovuma and Rufiji River deltas, offshore Mozambique and Tanzania, have proved to be the most prolific new offshore "basin" in the world in the past five years, with some 185 Tcf of natural gas resources already having been discovered since the first well (Windjammer-1 in Area 1, offshore Mozambique) in March 2010. Given the length of the coastline (about 4000mi from Somalia to South Africa) and the licenses around surrounding islands (e.g. Madagascar and Comoros), the deepwater of the region remains largely unexplored with only 85 wells drilled in the last five years; 85% of which are within a 250mi "golden-zone" running either side of the Tanzania-Mozambique border. The wells drilled offshore East Africa during the past five years are summarized in Table 1.

Gas was first discovered onshore East Africa in the 1960s, albeit at a significantly smaller scale than the current offshore volumes. The most substantial onshore discoveries were Pande (discovered 1961) and Temane (discovered 1967) in Mozambique and Songo Songo (discovered 1974) and Mnazi Bay (discovered 1982) in Tanzania.

However, it was not until the 2000s that these more material accumulations began production. The limited local market and lack of infrastructure in the region – responsible for the delay in the development of these onshore fields – remains the major challenge for the monetization of the huge offshore gas resources. While plans for various local gas utilization projects – which will fuel industrial development – are being advanced, particularly in Mozambique, the anchor for any such activities is onshore LNG and the associated infrastructure that will actually bring gas to shore.

Both Mozambique and Tanzania have sufficient gas resources already discovered (~150Tcf and ~36Tcf respectively – as reported by the operators) to justify LNG developments and although plans are progressing in both countries, no final investment decisions have yet been announced.

With a minimum of four years for construction, between project sanction and first LNG production, in these greenfield sites, the earliest LNG export dates from the region will be 2019-20 for Mozambique (which has already selected a site for the LNG plant in Cabo Delgado province) and 2022-23 for Tanzania. However, project finance also still needs to be put in place to fund these developments and with each two train plant costing in the region of \$20-30billion, further delays may be envisaged in the current climate.

Future prospects

Figure 1 shows the current licensing position offshore East Africa along with highlights of recent drilling activity as summarized in Table 1. Only 13 wells have been drilled in deepwater East Africa outside of the Rovuma/Rufiji golden-zone in the last five years. No wells have been drilled offshore Somalia, Madagascar, Comoros or the eastern margin of South Africa in this period. Of the wells drilled, none have found sufficient hydrocarbon and/or encountered reservoirs of the quality to be deemed commercially successful, and in fact despite published gas discoveries, some operators have decided to relinquish their holdings (e.g. BG in Tanzania Block 3 and Apache in Kenya Block L-8). It is therefore apparent that the understanding of the deepwater petroleum systems, offshore East Africa, is still very much in its infancy. But with the scale of the recent successes discussed above, exploration potential remains high.

Currently (January 2015)

Country/Block	Operator(s)	E & A wells completed	Wells reported commercially successful	Success rate	Notes
Mozambique Block 1	Anadarko	32	26	81%	
Mozambique Block 4	Eni	13	12	92%	
Mozambique Blocks 2/5	Statoil	2	0	0%	Relinquished
Mozambique Blocks 3/6	Petronas	1	0	0%	
Mozambique Others	Sasol	2	0	0%	
Tanzania Blocks 1, 3 & 4	Ophir/BG	17	17	100%	BG withdrawn from Block 3
Tanzania Block 2	Statoil	10	10	100%	
Tanzania Others	Ophir, Petrobras	4	0	0%	
Kenya	BG, Apache, Anadarko	4	0	0%	Sunbird-1 discovered oil in Block L-10A; Mbawa-1 discovered gas in Block L-8, but operator Apache has exited license

Table 1: Wells drilled offshore East Africa from 2009-14 and their reported results.
Source: Deloittes Petroview

there are only two drillships active in the region (*Belford Dolphin* for Anadarko in Mozambique and Discoverer Americas for Statoil in Tanzania: *Deepsea Metro* is stacked in Tanzania), from a high of five in November 2012, and four operating as recently as August 2014 (Baker Hughes' Rig Count). It is difficult to conceive at the present time of any increase through 2015. Depending upon the results of the ongoing interpretation of seismic and wells in Kenya, Tanzania and Mozambique, and the remaining exploration periods for licenses across East Africa, the drillships already in the region could potentially be assigned to any number of prospects through the year, but it is most likely that for the time being they will be focused on the Rovuma/Rufiji areas. It should be noted that the formal exploration period for the 2nd Round blocks in Mozambique (including Areas 1 and 4) was eight years and so will be expiring shortly. The 11-year exploration period for the Tanzania licenses means that there are still 2-4 years remaining for the current license holders there.

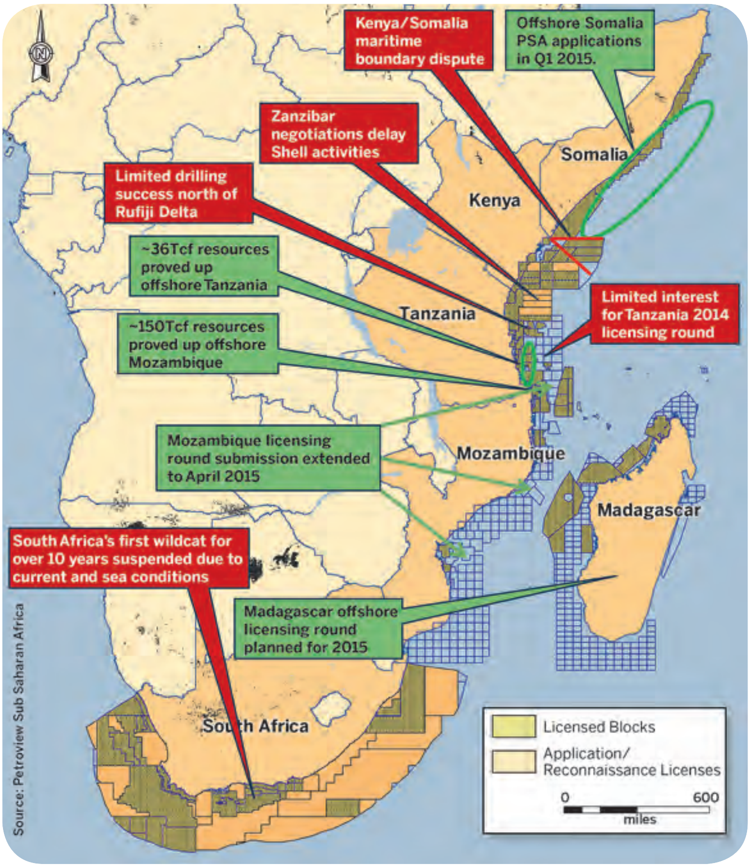


Figure 1: East Africa licenses and activity comments.

Although drilling activity may quieten during the coming year, additional acreage will be coming available. Mozambique is currently offering its 5th Licensing Round with 15 blocks being made available offshore Rovuma, Angoche and Zambezi (see Figure 1). Following representation from the industry INP (National Petroleum Institute) has extended the deadline for applications to 30th April 2015. Madagascar has stated that it is planning to offer 30-50 offshore blocks in a license round later in 2015 once a new petroleum code is approved by parliament. Soma Oil & Gas has completed a seismic option agreement over an extensive offshore evaluation area and reconnaissance area in advance of submitting PSA applications with partners to the Federal Government of the Republic of Somalia in 1H 2015.

A key consideration with respect to future activity offshore East Africa is whether there remains any appetite for exploration for additional gas resources outside of the blocks where commercial volumes have already been proved? If not, there is a real need to resolve the riddle of where oil may have been generated and trapped offshore. Oil discoveries and developments onshore East Africa in Madagascar, Mozambique (Inhassoro) and Kenya (Lokichar), as well as the Sunbird discovery in a carbonate reef offshore Kenya (Block L-10A) and the presence of oil seeps along the margin, continue to tantalize.

Cautionary notes

Real success has only been achieved in a very limited area offshore East Africa, and even here has yet to generate any revenue. There is still a long way to go to crack the codes of the other plays along the East African margin. However, it is not just the geology that remains the challenge. Terms originally intended to attract have led to the current license position (see Figure 1), but the recent exploration successes have strengthened the hand of the host countries and are prompting governments to update petroleum codes and license terms.

Tanazania's 4th licensing round in 2014 attracted minimal interest, and was accompanied by tougher new PSA terms. In South Africa, concerns over the impending Minerals and Petroleum Resources Amendment Bill have meant there has been no offshore drilling activity for over a decade, other than for Total's Brulpadda well, which unfortunately was suspended in October 2014, due to mechanical issues related to extreme current and sea conditions. In most areas, early mover advantage is now over.

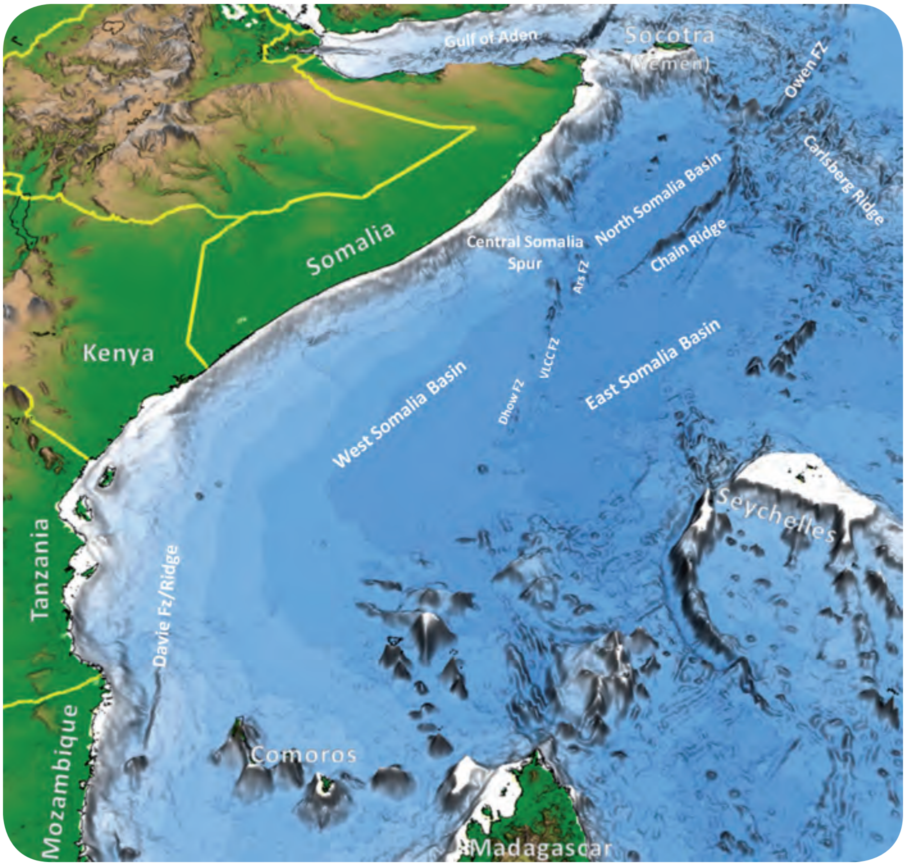
In a scramble to be part of the economic boom that hydrocarbon production is anticipated to bring to all of East Africa, individual states are jostling for position. In its pursuit of appropriate revenue sharing with Tanzania, Zanzibar's semi-autonomous government has effectively blocked any work on four licenses awarded to Shell since 2002. Maritime boundary disputes are always a concern, and as recently as August 2014, Somalia took its claims for a southeasterly trending boundary with Kenya, following the line of the land border, to the United Nations (see Figure 1), a concern for licensees in the now disputed zone.

Right now, of course, oil price is a hugely limiting factor on the number of high cost deepwater wells likely to remain on company's drilling plans in the immediate future, particularly as the priority objective now is to find a working oil province.

Five years ago no-one expected to have been able to prove up gas resources on the scale of those in the Rovuma Basin. With so much of East Africa's deepwater virtually undrilled, not least Somalia, Madagascar and South Africa, we can but hope for continued success in the coming years. OE

***Jeremy Berry** serves as global business development director at Gaffney, Cline & Associates. His primary technical strength is in the geosciences. Berry has an in-depth understanding of sub-Saharan Africa.*

Challenges in the deep



The East African coastline. Image from the GRID-Arendal Continental Shelf Programme.

Gas has been found in great quantities offshore East Africa. What will be the challenges around getting it to shore? Alex Hunt takes a look.

Offshore East Africa is rapidly emerging as an exciting new frontier exploration play. Major gas discoveries, with volumes currently estimated to exceed 100 Tcf, have been made offshore Mozambique and Tanzania. An oil discovery has also been made offshore Kenya.

Further south, exploration licenses have been awarded offshore Madagascar and South Africa. Seismic data is currently being acquired and processed. In the far north, Somalia has been considering an offshore licensing round, although this has been delayed by the formation of a new government administration and negotiations with Kenya over the maritime border.

While no offshore field developments have as yet been sanctioned, a number of pre-FEED concept selection studies have been awarded. Final investment decisions for the first projects are likely to be made within the next three years. Almost all of the current discoveries are in water depths greater than 1000m. It is possible that both subsea facilities and floating production systems will be required.

However, the region has some very challenging characteristics that will require an integrated multi-disciplinary approach. Offshore production facilities will need to be designed for both installation and operation.

Metocean challenges

The seabed topography of East Africa is characterized by a very narrow continental shelf. To the south, it is less than 5km wide. However, to the north, it can extend out to about 50km. Water depths on the shelf are up to 400m.

This is followed by a steep drop to the ocean floor and water depths of more than 2000m. Slope gradients are typically up to 10%, although these can exceed 15% in places. The seabed then slopes more gently downwards to water depths in excess of 4000m.

The floor itself has a large number of ridges and sea mounts that are hundreds of meters in height. There is also a series of deep underwater canyons running out perpendicular to the shoreline that are hundreds of meters wide and kilometers long.

All of these obstacles, the very undulating terrain and steep slopes will pose significant challenges for identifying suitable routes and landfalls for future flowlines and pipelines.

In the Indian Ocean to the north of Madagascar, the surface current circulation is normally clockwise, although there is an equatorial counter-current in winter. However, to the south of Madagascar, the current changes direction and circulates counter-clockwise. Between Madagascar and the mainland, the Mozambique current flows from north to south and is magnified by the channeling effect between the two land masses.

There are also two monsoons. The north-east monsoon or kaskazi brings dry air in from the Persian Gulf from November to April and the warm, moist kusi monsoon blows in from the south-east from April to October. The slightly cooler kusi brings the heavier rains, from late March to early June. There is then a second rainy season in November and December. These may therefore place limitations on installation activities.

Because this is a frontier area, the oil and gas industry currently has limited operational experience and knowledge. The seabed bathymetry is now being surveyed and mapped. There is maritime information available on surface currents, wind speeds and directions.

However, more data is needed on the strengths and directions of currents through the water column. Long-term data gathering campaigns using acoustic doppler current profilers (ADCPs) will provide the information required for the design of risers and moorings for floating production systems and will also support the planning of optimized installation programs.

Dry gas reservoirs

Although oil has been discovered offshore Kenya, the major finds to date have been dry gas reservoirs offshore Mozambique and Tanzania. One of the development options being considered is 'subsea to beach' full wellstream transfer with no floating production systems. However, dry gas reservoirs are defined as having no hydrocarbon liquids present. They will contain formation water.

As these reservoirs are produced, pressures and temperatures within the production systems will fall. Water, initially present as vapor, will begin to condense. These systems will therefore need to operate, at least in part, in the multiphase region.

In addition, since water will be present, it is likely that liquid corrosion and hydrate inhibitors will need to be injected for transportation over relatively long distances. This will increase the volume of liquids in the production systems and push them further into the multiphase region.

Multiphase flow

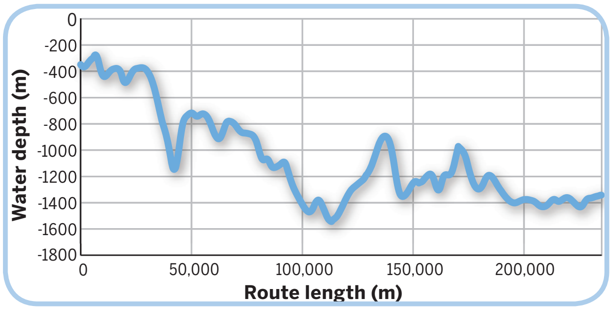
As pressures and temperatures fall, the gas velocity increases. Although a production system with low liquid loading might start in the stratified flow regime, the effect of the increasing gas velocity will be to move it into stratified wavy flow and, eventually, into slug flow. Each of these flow regimes has a greater pressure drop per unit length, so pressure drops will increase as the fluid moves closer to shore.

With the pressures and temperatures decreasing, more liquids will condense. The presence of more liquids increases the likelihood of a change in flow regime, leading to increasing pressure drops. These in turn cause more liquids to condense. The situation therefore escalates.

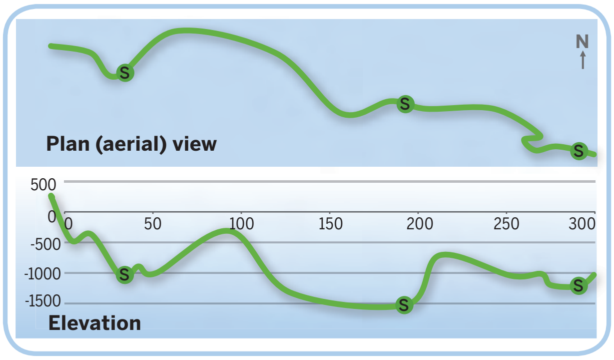
When the fluids reach the base of the continental shelf, the production systems will need sufficient pressure for the fluids to be able to climb the slope and reach the shore. The back-pressure in the system will limit natural flow and reduce reservoir recovery unless some form of pressure boosting is provided.

Slugging has two main causes. Hydrodynamic slugging is governed by gas to liquid ratios and flow velocities. However, terrain-induced slugging is related to the seabed topography. The major undulations of the East African seabed will increase the probability of slug flow and high pressure drops. Pipeline routes will therefore need to be selected that minimize these undulations in order to reduce the impact of terrain-induced slugging and overall system pressure drops.

High pressure drops are also undesirable if sand or solids enter the production system. The increasing gas velocity may eventually exceed the erosional velocity and the particles may damage pipework.



Typical seabed profile



Possible pipeline route with tie-in points for subsea pressure boosting.

In addition, in low flow or no flow conditions, gravity becomes dominant. With insufficient gas velocity to carry liquids and solids, they will drain downhill and back into the production system.

In the worst cases, the system may become liquid locked or blocked and the reservoir pressure available on restart may not be large enough to clear these accumulations, leading to loss of production. Overall, although the shortest distance between two points may be a straight line, the most efficient route to minimize pressure drop and liquid or solid build-up may not be the shortest or straightest.

Managing liquids

In order to avoid production systems becoming liquid-locked and to offset the effects of pressure drop as reservoir pressures decline, one option is to retrofit some form of subsea pressure boosting. Two-phase gas-liquid separation and multiphase pumping or compression offer one alternative. However, as the volumes of produced water increase, this may simply move the problem from one location to another further downstream.

For short tie-back distances this may be manageable, but the optimum solution would be to reduce the inventories of water and solids. This would have the added advantage of debottlenecking processing facilities later in field lives, when water handling facilities may become capacity-constrained.

In order to achieve this, three-phase subsea separation and pumping with produced water and sand reinjection is required. While this is a mature technology in water depths less than 1000m, further development and qualification would be required for deeper water applications.

Pre-investment

Offshore East Africa, pipelines and flowlines are likely to require more complex seabed routings in order to avoid major obstacles and to minimize the impact of pressure drop. Subsea boosting facilities may then be retrofitted where and when required in order to maintain production and increase reservoir recovery. However, pre-investment should be made in spool pieces, tie-in points and spare umbilical hoses to simplify subsequent installation.

This will require a truly multi-disciplinary project approach to develop designs that are suitable for installation and operation, both initially as well as during possible retrofit modifications later in field life. **OE**

This article is based on a presentation made in October 2014 at the DNV GL Pipeline Day London 2014.

Alex Hunt *is the founder of Woodview Technology Ltd., a consultancy specializing in the identification, development and implementation of emerging and new technologies for the oil and gas industry. With over 30 years' experience, he has previously held positions with Texaco, Total and BG Group, developing technology strategies and establishing and managing portfolios of research and development projects. He also lectures on flow assurance, subsea issues, deep water technologies, emerging trends and technology needs.*

Solutions

Upgraded pipe purging system

Huntingdon Fusion Techniques introduced an upgraded pipe purging system for high speed pipe joint welding, the QuickPurge III system.

QuickPurge III is made from material that is resistant to the higher weld heat present now that the dams are slightly closer to the welds and at the same time exhibiting lower outgassing rates to prevent weld contamination.

The sleeve between the dams reduces the volume to be purged by two thirds, ensuring quick purge time down to 10ppm of oxygen.

Using Intacal II combined with the integrated PurgeGate device, dams can be safely inflated with argon gas, prior to releasing it for purging the space between the dams where the weld joint is located.

This reduces the risk of inflatable dams bursting as a result of undue pressure increase or accidental flow increase of the inflation and purging gas.

www.huntingdonfusion.com

Paradigm's new testing technology

Paradigm Flow Services' new Dry-Flo fire deluge safety testing technology uses conditioned and dehumidified air to assess the functionality of deluge nozzles, with remote sensors strategically placed to pick up the air wave signatures throughout the deluge system. The signatures are then compared against hydraulic models, developed by Paradigm engineers, while sensors detect any deviations from optimum function. Dry-Flo testing addresses the risks associated with wet testing and corrosion, which can cause corrosion under insulation, water ingress to electrical junction boxes, and flooding of the process module drains. Additionally, the new technology eliminates the need to cover and protect electrical equipment, and can be conducted while the deluge system is live.

Paradigm Flow Services recently successfully demonstrated its Dry-Flo testing technology at its Drumoak, Aberdeenshire, office with a full-scale 50 nozzle deluge system, designed to replicate an offshore environment.

www.paradigm.eu

Wärtsilä 50DF powers LNG carriers

South Korea's Daewoo Shipbuilding and Marine Engineering ordered 54 Wärtsilä dual fuel engines to power 172,600cbm icebreaking LNG carriers.

For each LNG carrier Wärtsilä will supply 12-cylinder and 9-cylinder Wärtsilä 50DF dual-fuel engines. The total power output from the Wärtsilä engines is 64,350kW per vessel.

A Wärtsilä 50DF engine can give 950/975kW per cylinder and a total maximum mechanical output of 17,100kW. The engine speed is 500 or 514 rpm with 50Hz and 60 Hz applications. The maximum thermal efficiency is higher than with any other gas engine.

The engine is capable of operating on liquefied natural gas (LNG), heavy fuel oil, or low-viscosity marine diesel oil but LNG will be the main type of fuel to be used. When operating in gas mode, the nitrogen oxide emissions are at least 85% below those specified in the current IMO regulations, and CO_2 emissions are some 25% less than those of a conventional marine engine running on diesel fuel. Additionally, the sulphur oxide and particle emissions are negligible at almost 0%.

www.wartsila.com

Tritex releases new gauge

The Mark 2 Tritex Multigauge 3000 Underwater Thickness Gauge, measures metal thickness by using multiple echoes to pass through coatings up to 20mm thick. All measurements are error checked to ensure only accurate readings are displayed, even on uncoated metal. The gauge is simple to use, with little operator input, for multiple applications, including extremely corroded metal, with no probe zeroing, and has a large bright 10mm display which ensures it can be easily read by the diver, even in poor visibility.

The Multigauge 3000 uses multiple echo and single crystal probes in accordance with class society regulations. It has an integral battery with 55 hours runtime on a single two-hour fast charge, can easily be upgraded to a topside repeater, is built to withstand the harsh conditions of the underwater industry and all probes have protective membranes fitted to prevent damage from rough surfaces.

The gauge is supplied completely ready to use in a Peli case with all the necessary spare parts.

www.tritexndt.com

GE, McDermott launch new consultancy

A new oilfield consultancy has been launched by GE Oil & Gas and McDermott International to "transform the development of front-end solutions for offshore fields."

io oil & gas consulting, deliberately spelled without capital letters by the two firms, is based in London and headed by CEO Dan Jackson, with Mark Dixon as Chief Technology Officer, both formerly of DeepSea, bought by McDermott in 2013, and Tony McAloon as COO. Oliver Dixon will serve as CFO.

Jackson says: "The oil and gas industry is a vital component in the global energy mix, but increasing complexity of offshore field developments and the decline in oil price is challenging traditional ways of working. Now is the ideal time to launch io."

io's offer will range from portfolio evaluation, exploration and planning support, appraisal and feasibility, conceptual engineering and FEED to the final investment decision, especially in new, deepwater developments, by "leveraging the contractor community knowledge base."

The firm has plans to open satellite offices in the US and Asia. ■

Ocean Installer opens Brazil office

Subsea contractor Ocean Installer opened an office in Rio de Janeiro, Brazil. The company says it has seen an increasing demand for targeted vessels in the region and the short time frames in which accurate engineering solutions is demanded. The office will initially target projects for the local subsea support market. Marcelo Mendonca has been hired to lead the Rio office. "We have seen the need to establish an office to serve the Brazilian oil and gas market. Brazil is a very interesting region and the 'pre-salt' reservoirs hold exciting opportunities for us," says Steinar Riise, Ocean Installer CEO.

Aramco Asia inaugurates Singapore office

Aramco Asia recently inaugurated Aramco Asia Singapore, as part of its ongoing expansion in Asia, to provide crude oil marketing, material sourcing, supply chain logistics, inspection and other engineering services.

Asia is the company's biggest crude oil and products market with 60% of Aramco's crude oil being exported to Asia. Aramco Asia currently has six offices in China (Beijing, Shanghai, and Xiamen), Japan, Korea and Singapore.

"The inauguration of Aramco Asia Singapore underlines the importance of Singapore as the region's premier hub for oil and gas, as well as a regional base for the Southeast Asia region," says Fouad Al Rammah, representative director of Aramco Asia Singapore

"Asia is a key strategy and focus for us as part of our transformation efforts to become a leading global and integrated energy and chemicals company by 2020," says Ibrahim Al-Buainain, president of Aramco Asia.

AVEVA opens Saudi Arabia office

AVEVA opened a new office in Saudi Arabia to strengthen its presence in the Middle East and further enhance its growing global network.

The office will offer sales and support for all of AVEVA's solutions and services, with particular focus on owner operators and engineering, procurement and construction contractors in the oil and gas and power sectors.

"At AVEVA we recognize how important it is to provide service and support in local language and in accordance with local culture," says Helmut Schuller, AVEVA executive vice president, group sales. "Saudi Arabia represents a key market. It has the world's largest crude oil production capacity and the plan to increase electricity generating capacity to 120GW by 2032. We will be on the ground to offer solutions that can be used across the project and asset life cycle, ensuring our customers can anticipate changing technology needs and business objectives."

Nova Scotia tidal projects win funding

Nova Scotia's government has granted four awards that will help tidal energy developers deploy the first turbine arrays in the Bay of Fundy.

The approval allows the developers to enter into a 15-year power purchase agreement with Nova Scotia Power. The first turbines are expected to operate in the Bay of Fundy in 2015.

Four developers have received approval for a total of 17.5MW of electricity: Minas Energy (4MW), Black Rock Tidal Power (5MW), Atlantis Operations Canada (4.5MW), Cape Sharp Tidal Venture (4MW)

Nova Scotia's tidal energy sector has reached significant milestones this year. Government signed a memorandum of understanding with InnovateUK in the United Kingdom for collaborative research, FORCE deployed four sub-sea power cables in the Bay of Fundy in the fall, and Halifax hosted the International Conference on Ocean Energy in November

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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)*

OAA shortlist revealed

The waiting is over - the shortlist for the 2015 Offshore Achievement Awards, supported by OE, has been announced.

Alexandra Pate, a Robert Gordon University student, designed the trophy for this year's Offshore Achievement Awards.

The annual awards, organized and hosted by the Society of Petroleum Engineers (SPE) Aberdeen Section, recognize exceptional performance across 12 categories, from individual achievements to company performance and innovations in safety and technology.

Ian Phillips, SPE Aberdeen director and chief executive of the Oil and Gas Innovation Centre, said: "These awards are a great platform for companies and individuals to gain recognition and this year, we have had more entries than ever. There was a particular increase in nominations in the Emerging Technology and Small Company categories which is extremely encouraging. It is vital to the longevity of the energy industry that new technologies are continually being developed and new, smaller players often play a key role in this innovation."

The 2015 Offshore Achievement Awards finalists are:

Innovator
- Expro North Sea
- Proserv
- Return to Scene
- WEB Rigging Services

Emerging Technology
- Churchill Drilling Tools
- Delphian Ballistics
- Paradigm Flow Services

Safety Innovations
- Nautronix
- Senscient
- The Survitec Group

Environmentalist
- CETCO Energy Services
- Paradigm Flow Services
- Sureclean

Export Achievement
- Alba Power
- Tekmar Energy
- Wireline Engineering

Working Together
- Decom North Sea
- Maersk Oil
- Senscient

Outstanding Graduate Program
- ACE Winches
- Maersk Oil
- Petrofac Offshore Projects and Operations

Young Professional
- Brendan Forbes, Sparrows Group
- Rory Gregor, Petrofac
- Murray Kerr, SengS Subsea Engineering Solutions

Inspiring Leader
- Murray Kerr, SengS Subsea Engineering Solutions
- Mal Lowe, Petrofac
- Dr Liane Smith, Wood Group Intetech

Great Small Company
- ASET International Oil & Gas Training Academy
- Merlin ERD
- SengS Subsea Engineering Solutions

Great Large Company
- Aker Solutions
- Proserv
- Stork

Significant Achievement
- Announced at the ceremony

The awards ceremony takes place at the Aberdeen Exhibition and Conference Centre (AECC) on 12 March 2015.

Subsea excellence recognized

The winners of the annual Subsea UK Awards will be announced at a gala event, on 11 February at the Aberdeen Exhibition and Conference Centre during Subsea Expo.

Fisher Offshore, Proserv and ROVOP are all in contention for the Subsea Company of the Year award.

Express Engineering Oil & Gas, Flowline Specialists and Tekmar Energy have been short-listed in the Global Exports Award category, with ToolTec, Ocean Installer and Cambla vying for the New Enterprise award.

The shortlist for the Innovation & Technology award comprises Tracerco, Subsea Technologies and Tritech International, while Alan Muirhead from Ingen Ideas, Dale Tansley of Quick Hydraulics and John Stoddard from Proserv are the individuals short-listed for the Emerging Talent Award.

An individual who has made the most outstanding contribution to the subsea sector will be announced on the night.

The awards event is held during Subsea Expo, sponsored by OE and running 11-13 February. The event is expected to be its largest ever this year. ■

Spotlight

By Elaine Maslin

Technology, collaboration and the future

Early in 2014, John Wishart, energy director with Lloyds Register, and former group managing director and president of GL Noble Denton, joined the Industry Technology Facilitator (ITF) as its non-executive chairman.

It couldn't have come at a more interesting time for technology development and the role of technology in the 21st century oil industry, where he says, collaboration is key.

"Technology will be an enabler," he says. "If you look at the business challenges we face today – the issues around safety, the environment, and costs - you realize we need to embrace technology even more. We need to look harder at technology to help solve many of those issues. Development and adoption of technology is also going to require a lot more collaboration, as the cost of doing development work and adopting technology is hugely significant."

"That's why ITF became so interesting to me," Wishart says. The UK-based ITF works to solve targeted challenges through collaboration through its international membership. Since 1999, it has launched more than 200 joint industry projects securing more than £60 million funding from members.

To an extent, engineering, with a global perspective, is in John Wishart's blood. His mother is from Fiji and his father was an engineer from Glasgow, while he was brought up in Liverpool.

Science and engineering have been at the heart of his career and have been a passion since school, where he was encouraged by a teacher to undertake a degree in chemical engineering. From university, he went to Scottish engineeringmarine engineering and shipbuilding firm John Brown E&C in London.

He was then posted to Denmark, and then seconded to BP, which took him from the contracting world to a major operator, working in project and facilities engineering.

Wishart's next step was joining newly founded Genesis Oil & Gas, moving to Aberdeen, and then Houston, by which time the company was owned by Technip. There, Wishart rose to become Technip's US CEO, working on SPARS and subsea projects.

John Wishart

"Technip is a very technically orientated company and it stood out because of that. Historically, (as an industry) we have kept technology to one side," Wishart says. "What became apparent, through Technip and SPARS technology, deepwater risers, etc., is that technology helps solve business challenges in the broadest context."

With new technologies, there are risks, however. "Look at additive manufacturing and 3D printing," he says. "You are seeing it being used to make metal components. The aerospace sector is also looking at this. There are challenges with these methods. For example, how do you confirm it has been built to specification? When we introduce new technology we also have to think about what risks we are introducing. This is why ITF's contribution is important as the honest broker in the development and better adoption of technology."

Collaboration will also be a key factor in the future and should not be hampered by the current focus on cost reduction – the opposite, in fact, Wishart says. He suggests the industry should look at other sectors, like the automotive industry, where cars are made from parts manufactured by suppliers, enabling industrialized manufacturing and standardization.

"The oil and gas industry, on the other hand, is still bespoke and there is a need for that," he says. "But it doesn't have to be like that all the time." During his first 10 years in Houston, seeing operators use standard components, taking a "cookie cutter approach," was an eye-opener for Wishart. However, this could be done at that time, as reservoirs were more homogenous and less complex.

So what are the big themes the industry wants to tackle? Enhanced oil recovery and production optimiztion, drilling and how to drill smarter wells faster while maintaining integrity, plugging and abandonment, subsurface imaging, he says.

"The use of data is going to change how we do things," Wishart says. "It will mean new ways of working, new collaborations and how we learn from different technical disciplines. Chemical engineers will work with civil and electronic instrumentation engineers, working with mathematicians looking at algorithms and using statistical analysis.

"Technology is exciting," he adds. "There are incredible technology developers out there and bringing them together with key decision makers from operating and supply companies is the way forward to address specific technical issues and challenges in the oil and gas industry." OE

Faces of the Industry

By Kelli Lauletta

February's Faces of the Industry takes us on a subsea to topside career journey with Fernando Hernandez, technical advisor at Houston-based dynamic positioning company, C-Nav. Fernando shares how he went from working as an offshore mechanic to brokering global deals and advising companies on deepwater projects. Yes, a lot has happened in between.

At the current age of 30, Fernando has tucked away a decade of impressive industry experience that includes setting industry firsts in the Gulf of Mexico, a stint in the North Sea and he is now actively involved in cutting his teeth on Mexico's new deepwater frontier; spending his time between Mexico and America. A self-professed oil and gas junkie, Fernando says once he got into offshore he was hooked.

OilOnline recently visited with Fernando to get a fresh perspective on breaking into oil and gas, his view on Mexico's jump into deepwater, how to survive the downturn, and why he thinks cutting-edge technology is a combination of art and magic.

What is your current role in the industry?

In my role as technical advisor at C-Nav, I'm focused on North and Central America. In particular, we are keeping up with Mexico's energy reforms on deepwater activity, as highlighted by the Perdido Basin, as well as the developments at Lakach. When you operate in deepwater, everything changes, requiring dynamically positioned rigs, and breaking away from using jackup rigs, which are common in the Bay of Campeche.

C-Nav's technology will be key in Mexico—where it is currently used, as it provides 5-7cm accuracy to drillships, offshore construction and support vessels, for instance. The opening of Mexico's deepwater market is exciting. It is the equivalent of seeing the North Sea develop; there are obvious differences, but a lot of similar opportunities.

How did you break into the offshore industry?

I broke into the offshore world when a hiring manager asked, "Can you work a wrench and do you understand hydraulics?" To this I responded with a yes. Shortly after, I went to work at a Scottish-based company that had a US presence. I became intimately involved with working with ROVs and subsea tooling. That technology really drew me in. I went on to work in Aberdeen where I was trained to outfit ROVs for subsea intervention tasks to be carried out in thousands of feet of water. This experience opened a whole new world of technology and I was hooked. I came back to the US with a new perspective and an appetite to work on international projects.

I also learned that offshore is where the magic happens. It does test your mental agility and ability to adapt to remote and harsh environments. I liken it to military deployment, but with an emphasis on offshore technology, that trains you to prepare for 24/7 operations. Until there is a university on an offshore rig, there is no replacement for offshore experience.

What do you like most about your job?

Technology, technology, technology. Ten years from now your title will not matter. I have made it a point to work for companies that have less than four competitors globally. Working with technology that is new, innovative and cutting edge is very important to me. I'm reminded of a quote from Author C. Clark who said, "Any sufficiently advanced technology is indistinguishable from magic." I see it in the same way. Also in the patent process, the essence of innovation is based on the previous art, which has to be referenced. I perceive new technologies as a blend between magic and art. This really drives me in my career.

Do you have any interesting travel stories?

I had to cross into a country where the only rental car agency was not in service. So, I had to travel in a "chicken bus" traversing a dirt jungle and avoiding cows along the way. It wasn't even public transport, rather it was an old school bus painted orange with pictures of chickens on it. We eventually made it into a port. I will never forget that experience.

What is your advice for someone trying to break into oil and gas?

In the oilfield, you have to have initiative. I have seen candidates, with no guaranteed oilfield job, obtain a TWIC card to apply for an offshore opening. This type of resourcefulness places them a notch above other

Fernando Hernandez *is a dynamic positioning technical advisor at C-Nav for North and Central America. With extensive field experience in the ROV tooling, automated controls, subsea and well intervention sectors, Fernando's offshore background has given him a firm understanding of how to outfit vessels and rigs for offshore operations. His experience has also given him insights into how topside and subsea teams and equipment need to work in unison while deploying divers and ROVs to successfully execute challenging projects. His trilingual fluency has facilitated the execution of offshore operations, as well as the development of commercial relationships, domestically and abroad. At 30 years of age, he has more than a decade of oil and gas experience.*

entry level candidates. I'm not saying that everyone has to get a TWIC card to break in, however, it is important to demonstrate initiative and eagerness.

Also, transferable skills are very valuable. For example, a military veteran with a background in fiber optics and electronics can translate their skills into jobs in oil and gas, by working on automated controls used on blowout preventers.

What's the biggest career mistake you have seen?

The biggest career mistake I've seen are people who are driven solely by the monetary incentive of being offshore. It is critical to have a supplemental reasons for being offshore such as the thrill of seeing a new project take off, or being on the technological forefront. If you are only in it for the monetary reward, you will eventually burn out.

Do you have a pinnacle career story?

I have several career highs. One of those involved acidizing wells in deepwater via new rigless technology in the Gulf of Mexico around 2007. A second included the first completion of a well with solely an ROV skid, was a great experience.

Another came from working with a new record-setting hydrate remediation technology. I also led a division for a company that was one of the few players able to execute rigless abandonments. I helped the company expand its use of rigless technologies from the Gulf of Mexico to West Africa. Rigless technology is exciting because of the ability to workover a well without a riser from a dynamically positioned vessel. Additonally, another proud moment came from working on the cutting-technology to be used on the Åsgard project, when I worked in Norway.

Everyone is talking about oil prices right now. What's your take?

The ability to diversify is key. This is highlighted by C-Nav's technology, which is used not only on drillships, rigs, survey, pipelay and supply vessels, but can also be used for land projects, or for dredging a merchant marine port. This allows us to integrate and diversify into other markets during a downturn.

The theme of diversity rings true at the individual level, too. The more diverse you are in terms of skills and experience, the better off you will be during a downturn. Also, be flexible and willing to go back into the field or offshore if you are in an office position.

What are the key opportunities in the Mexico offshore market?

As Mexico's energy reform moves forward, Mexico is positioned to become a member of the deepwater golden triangle. For Mexico to realize its deepwater potential, it will need to bridge its technological and engineering gaps to ensure safe and successful subsea production. Foreign companies will also benefit, as Mexico looks for an infusion of products, services and intellectual capital to support Mexico's ambitions.

Fast forward to your retirement, how would you like to be remembered?

I would like to be remembered as possessing a passion for technology and a drive to work in different countries, and highly acceptant of new ideas. I'd like to earn additional patents and publish as many papers as possible to leave behind a foot print of my career. I also want to prove it is possible to start in the oilfield and end in the oilfield. That is my life goal– to retire as an oil man.

On the publishing side, Fernando is well on his way with multiple articles published in industry trade magazines, including *OE*. On the technology side, we predict Fernando's appetite will never be completely satiated, as he continues to search for the latest deepwater technological advancements. Fernando says: "I think once I realized I wanted to retire as an oil man, I put the car in 10th gear with full intent of wearing out the clutch." **OE**

Faces of the Industry features those who do extraordinary things for the industry. Nominate someone by emailing Kelli Lauletta.

Kelli Lauletta *is an experienced HR consultant and an editor for OilOnline.com. Email story ideas to klauletta@atcomedia.com.*

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Numerology

Photo by Harald Pettersen/Statoil

US$2.95 billion

The value of the Statoil-opeated Valemon HPHT gas and condensate development in the Norwegian North Sea. See page 14.

85 Tcf

The estimated natural gas resources in place at Mozambique's Area 4. See page 18.

2010

The year the first floating platform, Gjøa, with power from shore began production. See page 23.

Photo from ABB.

98.1 MMb/d

The estimated oil demand by 2020 from US EIA. See page 30.

119

The number of projects Keppel Shipyard has been involved in since 1981. See page 50.

90%

of UK production companies lack secure systems to protect all of their process control software See page 54.

72,000tonne

The topside lift capacity of a second Allseas megavessel being considered. See page 62.

US$1.5million

Estimated annual cost to operators for each offshore worker. See page 64.

2022

The earliest LNG export date from Tanzania. See page 66.