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# Subsea intervention



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ON THE COVER

**Adaptation.** When Stone Energy needed assistance intervening on its subsea well template at the deepwater Pompano field in the Gulf of Mexico, the company worked in collaboration with Cross Group to find a solution that would allow access to the field's through-flowline subsea system. The end result allowed flexibility for both risered or riserless intervention. See more of the story on page 50 of this issue of ***OE***.


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# Departments & Columns



"What changes do you expect to see in Mexico's offshore energy industry in the next five years?"

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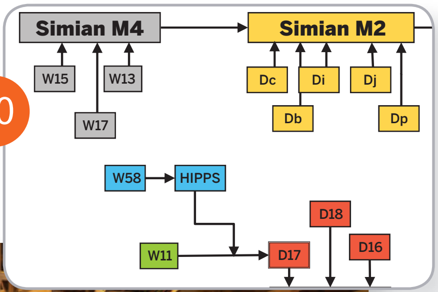


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# Online Exclusive

## Checking the pulse of oilfield service sector

Emma Gordon reports on the oilfield services market outlook as the industry continues to get to grips with new oil price realities.

Photo from Maersk Drilling

# People

## Wood Group Kenny gains CEO

Wood Group Kenny appointed Bob MacDonald as chief executive officer (CEO), effective 6 April. He will take his place on the Wood Group Executive Committee, reporting to Robin Watson who will take up his new position of CEO of Wood Group in April.

# What's Trending

## Onward and upward

- BP receives Mad Dog 2 approval
- Iran fires up South Pars Phase 12
- BG starts-up Knarr FPSO

Photo from BG Group

# Just for Fun

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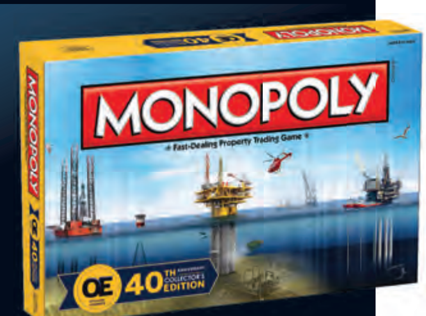



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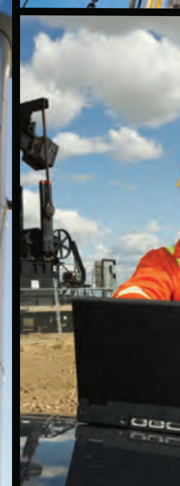







# Voices

**A new era.** With Mexico's Round One underway, OE asked:

## "What changes do you expect to see in Mexico's offshore energy industry in the next five years?"

The next five years will be a defining period for Mexico. The reforms will see Pemex calling on the global oil and gas support services sector directly for their state-of-the-art techniques and expertise in these challenging water depths. This approach will streamline the whole process from tendering to completion for international companies, making it easier to do business and opening up opportunities for organizations across the sector.

**John Reed,**
**chief executive officer, Harkand**

Energy reform will drive major changes in Mexico's offshore industry, the most significant being major IOC's competing or partnering to develop Mexico's deepwater fields. The momentous opening of the country's energy sector to private investors after 76 years of state monopoly has Pemex partnering with major IOC´s to tap hard-to-reach resources, promoting optimal development plans and top safety standards. An example is the Perdido field, where I foresee a major focus in the next five years. Perdido contains around 1.6 billion boe of prospective resources, split into 11 deepwater blocks now available for bid.

**Francisco Nunez Acosta**
**Regional Sales Manager Latin America**
**Subsea Production Systems, OneSubsea**

Deepwater exploration is costly, risky and time consuming, and relies on sophisticated technology and resources to ensure successful hydrocarbon extraction. Superior quality, reliable and safe performance in executing all stages of a deepwater project, from concept engineering through procurement, construction, installation and commissioning, and confidence in equipment and methods is imperative. We will closely watch how Pemex plans to obtain the expertise it needs from international energy majors for field development, as well as engineering and construction contractors, such as McDermott. We expect more companies will establish operations in the country.

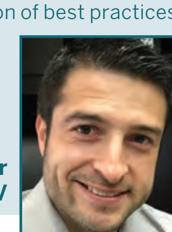
As Mexico becomes an established energy center, the benefits from hydrocarbon production will have a multiplier effect, providing opportunities for foreign investment, advancements in technology, jobs in the country and growth for the local economy to accelerate domestic wealth. It seems like a win-win opportunity.

**Scott Cummins,**
**Senior Vice President, Commercial, McDermott**

Increasing investment from international oil companies should ultimately bring the technology and capital needed to access greater offshore reserves. The initial benefit is likely to be increased access to shallow water reserves with deepwater reserves potentially following suit in the longer term. The development of local oil expertise will be a key factor in this process, along with an increasing transfer of technology to Mexican companies. This means new opportunities for the local workforce and new competition for local talent. However, there also needs to be a distinct drive to grow and develop that talent in order to develop a diverse and sustainable industry. For Penspen, training and development of local expertise will be a key part of succeeding in Mexico and supporting the oil and gas sector – Penspen have been using this model successfully all over the world, including in Mexico for the last eight years; so we understand it is a challenging path but it is also one we have walked many times before.

**Michael Simm, Executive Vice President,**
**Engineering and Project Management, Penspen**

In the short term, we should expect to see a decrease in drilling activity offshore due to low oil prices. However, assuming that oil prices will stabilize within the next few years, there should be a huge increase in drilling activity offshore due to the Mexico energy reform. This allows private international oil companies (IOCs) to invest via profit and production sharing contracts with the Mexican government, with the shared goal of increasing oil production in Mexico. Year to date, the first tender for the energy reform has been released as a shallow water tender. We should see its drilling activity effects in approximately two years' time, and more offshore tenders to follow in the next year. As IOCs invest in the region, we predict great improvements in the technology utilized offshore and in the adoption of best practices used in other parts of the world. In general, over the next five years we should experience a significant increase in activity for the energy industry and consequently, many opportunities for technology manufacturing leaders.



**Hector Sanchez, Area Manager**
**for Mexico and Central America, NOV**

Even though the general uncertainty in the global oil market, to which Mexico has not been exempt, there are important changes happening in the Mexican state policies. If low oil prices maintain during the following year, we may expect, in the short term, delays in the last bids of the reform, the ones that include deepwater, which could slow down the deepwater activity a bit, due to the higher costs it represents.

Although the outlook isn´t as promising as previous years, for the following years, there will be a continuity in the shallow waters propelled by the need of gain in production and the opportunities created by government for national and international oil and gas companies to invest in Mexico, which mean a clear potential of market expansion.

**Randy Mohammed - Regional Latin America Manager, Tubular Running Services, Weatherford**

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

# Undercurrents

## Not it: The race to avoid being first

At almost every oil and gas industry conference there will undoubtedly be a panel discussion where someone will make a wry remark about how unwilling operators are to be the first. No, not the first to produce oil or gas, but to adopt new technology. The oil and gas industry is the one industry where the goal is to be second.

There's no true incentive to be the first, because no one wants to be the company that took a chance and failed. And, when it comes to avoiding the next Macondo, that is an attitude that is understandable, yet somewhat defeatist. The oil and gas industry does many great things, and deploys some of the best technologies of any industry, including new innovations. But, there should be more done to encourage innovation and adoption of new technology.

At next month's Offshore Technology Conference (OTC) in Houston, NASA has been invited to showcase how its space technology – buoyancy, robotics, even artificial intelligence – could be applied to deepwater operations. ***OE*** has covered the partnership between Deloitte and NASA (*OE: March 2014*) that aims to highlight not only applicability but similarities between the two industries. This year also marks the first-ever "d5" series at OTC, which will showcase disruptive technologies.

While there is a common attitude that the oil and gas industry moves at an appropriate pace in terms of technological advances, there are occasions where failure to be the first to try out a new technology could mean millions of dollars wasted.

One of those times came for US operator Stone Energy (See full story on page 50). The company needed innovation. The Pompano field features a subsea template with a through-flowline tree system. One well had been out of production for about 10 years. Stone Energy was faced with either replacing the entire kit, or finding a solution that would allow flexibility for either risered or riserless intervention, and they eventually found it by working in collaboration with specialists to create that solution.

Smaller companies might face large obstacles in the current downturn, but one bright spot is that these leaner companies are able to take chances that some of the larger companies either cannot or will not. All the industry needs is an attitude change. OE

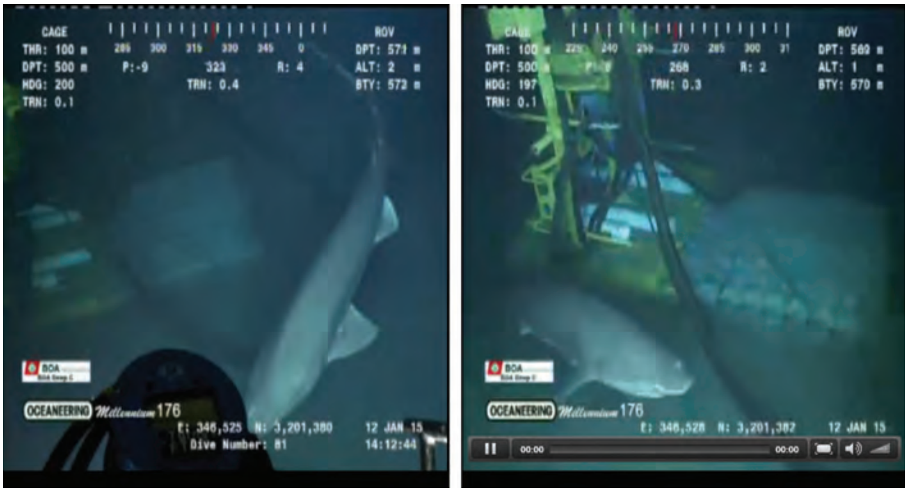



**PHOTO OF THE MONTH**

**During intervention operations on Stone Energy's Pompano subsea template, the ROV encountered an inquisitive shark.** Photos from Stone Energy.

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Craig May, Chevron Upstream Europe

# Pushing technology boundaries

Sir Ian's Wood Maximising Recovery report (MER UK), published last year, identified technology as an integral component to ensuring the success of maximizing the economic recovery of the UK Continental Shelf. As the Wood Report states, new field discoveries in the North Sea tend to be of a diminishing size and in more challenging environments, including deepwater. Technology needs to safely deliver cost reductions to enable new field developments in these marginal fields and improve competitiveness on existing assets, helping secure the long-term future of the UK oil and gas industry.

Deepwater drilling and reservoirs, like those found West of Shetland, pose unique challenges. The UKCS can leverage and benefit from technologies developed for deepwater environments, such as the Gulf of Mexico, where subsea separation, subsea compression and subsea samplings are opening up new opportunities and enabling further development of existing deepwater fields.

Fields that were previously considered stranded have also benefited from technology advancement, with increases to the maximum tie-back distances from under 50km in the 1990s to over 100km today. This capability has been an enabler for the development of these marginal fields and means that costly, new and dedicated facilities are no longer required.

While capitalizing on innovative technologies to develop marginal fields will play a key role in achieving MER UK, there is also a need to improve the recovery of resources from mature fields. A technology that has the potential to increase resource capture is enhanced oil recovery (EOR). EOR techniques increase the recovery of oil from reservoirs compared to more conventional recovery methods, such as waterflooding, and can benefit both existing and new fields.

At the Captain field, we have a proven track record of deploying innovative technologies, like extended reach drilling and novel artificial lift systems to access new areas and increase resource capture. Building upon this, we recently completed pilot trials of polymer EOR. The field was developed using proven technology in horizontal infill well development and the standard industry practice of waterflooding. At this stage of the field development, water injection alone is inefficient due to the high viscosity of the crude. This is the fundam,ental principle behind polymer flooding; low viscosity water is not very effective at pushing high viscosity oil out of the reservoir and into the production wells. Adding polymer to the injection water increases its viscosity and has the potential to improve the recovery of the relatively heavy Captain crude.

**"Technology has improved the recovery of resources and opened up fields that are challenged from either a cost or technical perspective."**

The use of polymer injection is a proven EOR system and is an established practice in onshore fields globally. Over the past five years, we have safely carried out polymer injection trials in the offshore Captain field. The successful outcome of these trials has demonstrated that polymer flooding is technically feasible in this field and has helped shape plans for full-field polymer injection deployment.

A key economic enabler for the pilot was the foresight shown by the field development decision to include some polymer handling capacity in the original facilities design for Captain. This illustrates the importance of giving serious consideration to the full life-cycle of the field when field development concepts are being analyzed, ensuring that EOR and late-life capability is assessed and factored into the design as appropriate.

In December 2014, the full field polymer deployment project successfully moved into front-end engineering and design and contracts were awarded to two UK companies. This represented a positive step towards commercializing the project and underlines our confidence in the expertise of the UK supply chain.

Detailed analysis is currently being conducted to further refine the project's chosen concept, which includes the installation of a new bridge linked platform that will house the polymer storage, mixing and pumping facilities. Modifications to existing infrastructure to tie in the new facilities are also in scope, alongside drilling and completion of new polymer injections wells.

Technology has improved the recovery of resources and opened up fields that are challenged from either a cost or technical perspective by making the impossible, possible. We need to continue to push the technology boundaries, to solve the challenges ahead and achieve the vision of MER UK. OE

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*__Craig May__ is managing director of Chevron Upstream Europe (CUE). CUE manages exploration and production in the UK, Norway, Denmark and Greenland. May earned a Bachelor of Science degree in Civil Engineering from Mississippi State University and a master's degree in civil engineering from Tulane University. May has worked for Chevron since 1981. Prior to joining CUE, he was Chevron Energy Technology Co.'s general manager for the facilities engineering department. May has also held a variety of positions in construction, facilities, project and technology management in the US, UK and Australia.*

# Global E&P Briefs


### A Big Foot sets sail

Chevron's semisubmersible drilling rig Big Foot set sail from Corpus Christi, Texas, to its new home in Walker Ridge Block 29 in the deepwater US Gulf of Mexico.

Big Foot is a dry tree extended tension leg platform (TLP), which boasts a production capacity of 75,000 bbl of oil and 25 MMcf/d of natural gas. The TLP will also have an on-board drilling rig and 15 well slots. Once it arrives, Big Foot will sit 225mi south of New Orleans, in in 5000ft of water.

The Big Foot project was sanctioned in 2010, only five years after the first discovery at the field. Chevron operates the field with 60% interest. It's partners include Statoil (27.5%) and Marubeni Oil & Gas (12.5%).

### B GOM production set to grow

The recent downturn in oil prices is expected to have minimal direct impact on Gulf of Mexico crude oil production through 2016 because of the long timelines associated with GOM projects, according to a new report by the US Energy Information Administration (EIA).

The EIA projects GOM production to reach 1.52 MMb/d in 2015 and 1.61 MMb/d in 2016, or about 16% and 17% of total US crude oil production in those two years, respectively.

The forecasted production growth is driven both by new projects and the redevelopment and expansion of older producing fields. Five deepwater projects began in the last three months of 2014: Stone Energy-operated Cardamom Deep and Cardona projects, Chevron-operated Jack/St. Malo fields, Murphy Oil-operated Dalmatian, and Hess-operated Tubular Bells. Also occurring at the end of 2014 was the redevelopment of Mars (Mars B) and Na Kika (Na Kika Phase 3), both of which are mature fields. Cardamom Deep, Jack/St. Malo, and Tubular Bells were slated for a late 2014 start-up, as well.

Thirteen fields are expected to start up in the next two years, eight in 2015 and five in 2016.

### C US lease sale earns US$538 million

Central Gulf of Mexico (GOM) Lease Sale 235 held in mid-March drew more than US$538 million in high bids.

A total of 195 bids on 169 tracts covering about 923,700 acres offshore Louisiana, Mississippi and Alabama, were made by 42 energy companies. BOEM estimates the sale could result in the production of 460-890 MMbbl, and 1.9-3.9 Tcf of natural gas.

Lease Sale 235 offered 7788 unleased blocks, covering about 41.2 million acres that are located from 3-230 nautical miles offshore in 9-11,115ft water depth.

Red Willow Offshore and Houston Energy made the highest single bid at more than $52 million. Shell walked away with the most bids at 17, followed by Statoil with 14, Venari with 12 and Chevron and ExxonMobil, each with 11 bids.

### D Petrobras begins production at Búzios

Production began at Brazil's deepwater Búzios field in the Santos basin, at 1600-2100m water depth. Petrobras is using the *Dynamic Producer* floating production storage offloading (FPSO) unit to drill, which is interconnected to well 2-ANP-1-RJS.

The early system will enable the company to produce for a six-month period and gather information to enhance the field's first permanent production system using platform P-74, says Petrobras.

### E Premier starts Falklands campaign

Premier Oil has begun their 2015 Falklands drilling campaign. The *Eirik Raude* semisubmersible drilling rig spudded well 14/15-5 on the Zebedee prospect, license PL004b, in the Sea Lion field complex. The well will test a total of seven stacked fan bodies with varying geological chances of success of 9-52%. Net prospective Pmean resources are estimated at 68 MMbbl in a range of 13-178 MMbbl. Sea Lion is 220km north of the Falkland Islands in 450m of water depth.

### F GDF Suez hits at Dalziel

GDF Suez E&P UK made a new discovery at the Dalziel structure in the UK Central North Sea. Well 22/16-6 flowed at rates in excess of 8000 boe/d and is now being side-tracked to appraise the extent of the discovery.

The exploration well, located in Block 22/16 in the P.1799 license, was drilled using the Transocean Galaxy II jackup rig.

GDF Suez operates the license with 30% interest. Its partners are RWE DEA UK (25%), JX Nippon E&P (25%) and Total E&P UK (20%).

### G Porcupine's potential spikes

Initial evaluation of 3D seismic data shows that Providence Resources's Drombeg prospect offshore southwest Ireland, is consistent with those of a large deepwater fan system. Drombeg is located in the southern Porcupine basin in frontier exploration license (FEL) 2/14, approximately


220km off the west coast of Ireland at about 2500m water depth. Further seismic interpretation work continues on the fast-track 3D volume and the main interpretation, mapping and seismic attribute analysis work will be completed on the final migrated 3D volume, which the company expects to receive at the end of this month (April).

## H Gas find boosts Aasta Hansteen resources

Statoil and its partners on production license 218 in the Norwegian Sea discovered gas close to Aasta Hansteen.

The Snefrid Nord discovery, estimated to contain 31-57 MMboe, will increase the Aasta Hansteen field development resource base by around 15% and improve the newbuild Polarled pipeline utilization, says Statoil.

Snefrid Nord is in the deepwater Vøring area, close to the three gas discoveries which comprise the Aasta Hansteen field development: Luva, Haklang and Snefrid South.

The discovery well 6706/12-2, drilled by *Transocean Spitsbergen,* proved a 105m gas column in the Nise Formation.

Statoil is due to drill a second exploration well in the vicinity of Aasta Hansteen following Snefrid Nord to increase upside in the area.

## I Mubadala to study off Morocco

Mubadala Petroleum signed an agreement with Morocco's Office National des Hydrocarbures et des Mines (ONHYM) to carry out an evaluation of the hydrocarbon potential of a large area offshore Morocco's Mediterranean coast. The agreement provides Mubadala Petroleum with an exclusive reconnaissance license to carry out detailed geological evaluation of the hydrocarbon potential of an area designated as Mediterranee Ouest. This is an area comprising 3433sq km offshore Morocco.

## J Eni encounters gas offshore Libya

Eni made a significant gas find at the B1-16/4 well in the Bahr Essalam South exploration prospect located in Contract Area D, about 82km from the Libyan coast and 22km from the production field of Bahr Essalam.

The well was drilled at 150m water depth, where gas and condensates were encountered in the Metlaoui formation of Eocene age. During production testing, the well showed to produce 29 MMscf/d and above 600 b/d of condensate. Eni estimates that the well will deliver about 50 MMscf/d and 1000 b/d of condensate.

## K VAALCO spuds Angola probe

VAALCO Energy spudded the post-salt Kindele-1 well, its first exploration well on Block 5 offshore Angola using Transocean's *Celtic Sea* semisubmersible drilling rig.

The well will be drilled to a planned total depth of 2250m in about 100m water depth.

The Kindele-1 well will test a fault block adjacent to the Mubafo discovery, which tested oil from the Mucanzo sand section within the Pinda group formations.

The Kindele-1 will be drilled to a depth of 1800m to evaluate the Mucanzo sand section. The well will then be deepened to the salt to an estimated depth of 2250m for geologic and geophysical correlation. The well is expected to take approximately six weeks to drill to total depth.

## L BP in second Nile find

BP made its second gas discovery in the East Mediterranean Sea at its North Damietta Offshore concession in the East Nile Delta.

The discovery was made at the Atoll-1 deepwater exploration well located about 80km north of Damietta city.

The well was drilled in 923m water depth using the *Maersk Discoverer* semisubmersible, which reached 6400m and penetrated approximately 50m of gas pay in high quality Oligocene sandstones.

## M Iran fires up South Pars Phase 12

Phase 12 of the giant South Pars gas field has been brought online. Phase 12, described as the biggest phase of the development, officially launched operation before the end of the current Iranian year (March 20), said the Iranian National Oil Company.

South Pars is the largest gas field in the world – sitting in shallow water in the Persian

Gulf and shared between Iran and Qatar, which calls it the North field. South Pars is estimated to contain 14 Tcm of gas, or about 8% of total world reserves. However, development has been slow, due to international sanctions.

### N KrisEnergy kicks off Thai campaign

Singapore-based KrisEnergy began its drilling campaign at the Rossukon-2 exploration well located in G6/48 in the Gulf of Thailand. The well lies about1km northeast of the Rossukon-1 discovery well.

Rossukon-2 sits at a water depth of 210ft and is planned to reach total depth of 5462ft using Shelf Drilling's Key Gibraltar jackup rig. The exploration well will test Early Miocene stacked fluvial sandstones on a broad structural high. KrisEnergy says that the well will also appraise the Rossukon-1 reservoir, which tested 850 b/d of oil, and is designed to identify additional volumes of oil that could move the discovery closer to commercial development.

### O Eni adds to Merakes

Italy's Eni completed post drilling studies, which indicate increased gas potential at Merakes-1, off Indonesia.

In the East Sepinggan block off East Kalimantan (Borneo), Merakes-1 sits about 170km south of the Bontang LNG plant and just 35km south of Jangkrik field.

Eni says new studies increased the find's potential from the previous 1.3 Tcf to 2 Tcf of gas in place.

### P Malampaya DCP installed

Mammoet installed the Malampaya Phase 3 depletion compression platform (DCP) in the West Philippine Sea for Shell Philippines Exploration.

The DCP is a self-installing platform that floats into place over its end-location, next to the Malampaya Shallow Water Production Platform, after which the legs are lowered onto the prepared seabed.

The platform is being held in its raised position, with its 80m legs secured on the seabed, awaiting the completion of the operation to weld it in place and install the connecting link-bridge by Mammoet.

### Q Qinhuangdao online

CNOOC's Qinhuangdao 32-6 comprehensive adjustment project has commenced production.

The Qinhuangdao 32-6 oilfield is located at the central north of Bohai Bay with an average water depth of approximately 20m. The main production facilities include four platforms and 99 producing wells. This project is fully on-stream and expected to reach its ODP designed peak production of approximately 36,000 b/d in 2015.

Operator CNOOC holds 75.5% working interest with partner Chevron China Energy Co. holding 24.5%.

### R Tap wins offshore

Perth, Australia-based explorer Tap Oil has been awarded 100% of Blocks W14-07 and W14-16, in the Barrow and Dampier sub-basins on Australia's North West Shelf, as part of Australia's Work Program Round 1.

W14-07, now Petroleum Exploration Permit WA-515-P, is on the Rankin platform in water depths ranging from less than 100-400m and covers about 485sq km (6 graticular blocks).

W14-16, now Petroleum Exploration Permit WA-516-P, is to the east of the Alpha Arch on the western flank of the Barrow sub-basin in 50-200m water depth and covers about 160sq km (2 graticular blocks).

## Contract Briefs

### DOF wins IMR contract

Chevron Australia has awarded DOF Subsea Asia Pacific a three years master services agreement to work on projects on the Australian North West Shelf. DOF Subsea will deploy the DP vessel *Skandi Protector* to undertake this work supported by management, engineering and logistics team based in Perth.

### Technip gets Lula subsea gig

Tupi BV awarded Technip a contract to supply high technological flexible pipes for the Lula Alto pre-salt oil field off Brazil.

The contract, estimated at more than US$560 million, includes Technip to supply around 200km of flexible pipes and associated equipment, including gas lift, gas and water injection, gas export and production lines. Delivery is scheduled to begin in 2H 2015.

Technip's Rio de Janeiro operating center will perform the project management and engineering.

### ABB to provide Johan Sverdrup power

Statoil selected ABB to provide land-based power supply for Phase 1 of the Johan Sverdrup field development in the North Sea, about 140km west of Stavanger, Norway.

The US $133.5 million contract covers delivery of electrical equipment for a converter station by the Kårstøprocessing complex at Haugsneset in the municipality of Tysvær, and a power module on the riser platform at the Johan Sverdrup field center. The equipment will be delivered during 1H 2017.

Total cost for the power supply to Phase 1 has been estimated at around $728 million (NOK 6 billion) (2015 value).

### Fugro selected for pipeline inspection contract

Statoil and Gassco chose Fugro for its 2015 annual pipeline inspection.

The contract covers defined sections of subsea pipelines between Norway and continental Europe: Europipe 1, Europipe 2, Franpipe, Zeepipe and Norpipe. Inspection of pipeline sections for production fields in Norwegian waters is also included in the contract.

Fugro will utilize its Echo Surveyor Hugin 1000 autonomous underwater vehicle (AUV) equipped with EM2040 multibeam echosounder and EdgeTech Full Spectrum 120 & 410 kHz side scan sonar. The AUV will be deployed from Fugro's multipurpose survey vessel *Geo Prospector*.

The survey is scheduled to commence in May 2015 and the confirmed workscope has an estimated duration of 30 days.

### GE wins $850 million Ghana contract

GE Oil & Gas won a US$850 million contract for the supply of equipment to the Offshore Cape Three Points (OCTP) block, Ghana, 60km from the coast.

This order includes both turbomachinery and subsea elements, with the first shipment planned for 4Q 2015. Further shipments are planned in order to deliver first oil by 2017.

The Turbomachinery scope has been awarded by Yinson Production (West Africa) Pte Ltd. and will be delivered solely by GE. The subsea scope of the order was booked directly with Eni Ghana and its partners. The system will be delivered by a consortium between GE Oil & Gas and Oceaneering, International, and includes the subsea production and control system (SPS) and umbilicals engineering, as well as project management, fabrication, transport, and testing. ▪

# West Delta Deep Marine-
# **Expansion beyond Limits**

**When the West Deep Delta Marine development came onstream offshore Egypt in 1999, it was planned to have a 25-year field life. It's now on its Phase IXa development, with 58 wells, seven with HIPPS, and 14 manifolds. None have been plugged and abandoned yet. Intecsea's David Smith, who has been working on the project from the start, explains WDDM's continuing expansion.**

West Delta Deep Marine (WDDM– BG Group 50 %, Petronas 50%) is off the north Egyptian coast, abutting the Rosetta block, approximately following the 200m seabed contour.

The development, which was the first deepwater field offshore Egypt, extends from around 300-1200m, water depth, employing diverless subsea technology within confines of the block.

The initial development commenced in 1999, and was dedicated to the domestic market in Egypt, with the core infrastructure of the main transmission pipelines from the pipeline end manifold (PLEM) to the shore reception facilities, built at Idku, near Alexandria. It was designed to allow for expansion from the initial 700 MMscf/d to 2000 MMscf/d. Subsequent phases were to be dedicated to the adjacent LNG plant and to maintain a production plateau throughout a field life of 25 years.

Intecsea has worked in partnership with the joint venture company operator Burullus (EGPC 50%, BG Group 25%, Petronas 25%) and undertaken the conceptual design, front-end engineering design and the technical assurance for all phases of WDDM development to date and is currently supplying a technical assurance support team to Burullus on the latest Phase IXa development.


**Scarab Saffron phase UV SDA.**
Images from Intecsea.

### Fit for purpose from day one

To provide a sound and structured development, the emphasis was on using proven, qualified technology, simple fit-for-purpose designs, with no single point failure causing a complete shutdown of the subsea system.

The gas produced from the WDDM reservoirs is sweet, but pressures and temperatures are such that there is a continual risk of hydrates from the produced water. Continuous mono-ethylene glycol (MEG) injection, complete with corrosion inhibitor, is provided via dedicated pipelines routed to each field area. In addition to the produced water, the Sapphire field also produces a significant amount of condensate that is required to be extracted prior to the gas entering the domestic market or the adjacent LNG plant.

Pipelines on WDDM are carbon steel ranging from 10in for well flowlines, to 20in and 26in-diameter for infield pipelines.

These infield flowlines eventually terminate at the PLEM, where 24in and 36in-diameter pipelines provide the export capacity to the onshore plant.

With fishing activity possible, the larger pipelines are designed for fishing gear pullover loads and the smaller 4in lines and umbilicals are trenched. Subsea structures in the shallower waters are designed to be overtrawlable, while in deeper waters, the structures are upright. Initially considered for up to 200m water depth, this has been increased to 400m for phase IX.

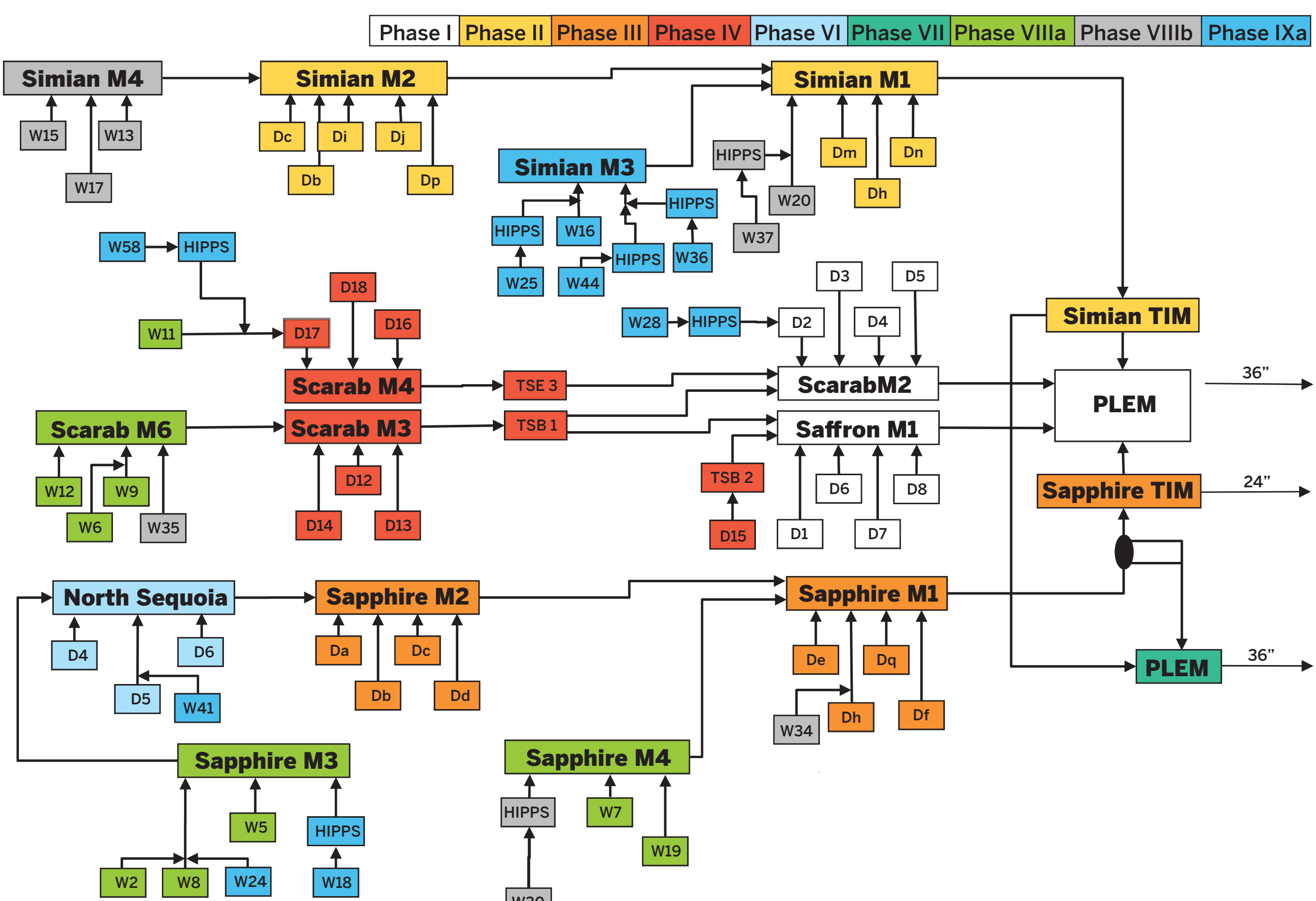
Subsea equipment includes horizontal trees, with the flowloop connector hub mounted directly on the tree body, and remotely installed tie-in jumper spools connecting the trees and manifolds to the infield flow lines.

### The first fields

The Scarab/Saffron fields were the first to be developed, using eight wells connected to two production manifolds with an Aker Solutions (formally Kvaerner) electro hydraulic multiplexed control system expandable by two wells and one manifold. These are controlled directly from the shore terminal, 90km away, with a


Simian platform.

## WDDM FIELD SCHEMATIC




**Simian SDA.**

distribution unit and "repeater module" at the manifold center 80km from shore. Twin 20in main export pipelines commence at a water depth of 415m and run for 30km to the PLEM at a depth of 95m, where 24in and 36in export lines convey the product to the shore terminal. A 4in pipeline conveys MEG from shore to the field for hydrate inhibition by direct injection at the trees. The Scarab/Saffron fields started producing in 2003 at about 700 MMscf/d.

The Simian/Sienna (Phase II) and Sapphire (Phase III) fields were the first planned expansions to provide gas to the new LNG plant, with six wells at Simian, two at Sienna, and eight at Sapphire. Each field area had two manifolds. Designed expansion for each field was again four wells and one manifold. The flows from these fields are brought together at the PLEM where gas from all the fields is commingled into the export pipelines to shore.

For the phase II and III developments the contracting strategy was from an offshore management contractor, phase I, to a total turnkey offshore EPIC, resulting in a change of umbilical and control systems supplier.

The subsea wells are controlled via a GE (formally ABB Vetco Gray) electro hydraulic multiplexed system, with controls, hydraulic power and methanol injection equipment mounted on a controls platform, strategically positioned in shallower water close to the PLEM.

Phases II and III added a further production capacity of 1400 MMscf/d, allowing overall WDDM production to exceed 2 billion scf/d, the nominal plant capacity.

## Phase IV: outgrowing the infrastructure

Phase IV was the first expansion of an existing field area and added seven wells and two manifolds to the Scarab/Saffron production hub, which exceeded the initial control system design.

The expansion was complicated by the requirement to incorporate west gas flowmeters (WGFM) and operator adjusted glycol control units (GCU), previously ROV adjusted, following their introduction on phases II and III. In addition, the original subsea electronics module was now obsolete and the replacement required a revised "repeater module" to accommodate the communications differences.

The incorporation of a new design of communications repeater module was relatively straight forward; a structured qualification program being implemented to prove the design prior to installation.

The other issue was providing sufficient power, although with the existing dual power supplies the system was still functional. However, single channel operation, with the system as configured, was not possible; effectively removing the system redundancy. Typically all sensors within the subsea control module (SCM) were powered up on the application of system power, allowing data to be displayed as soon as communication is established. In the case of the WGFM, which had significant inrush and steady state current, data is only required once the well is producing. Although it is not the control system vendor's normal process, modifying the software to have the WGFM "OFF" on power-up reduced the system loading to an acceptable level for single channel operation.

Process expansion to allow the two additional manifolds to be located adjacent to the existing structure was straight forward and achieved using tie-in spool bases, which provided the necessary separation.

Phase V added onshore "boost" compression and had no impact on the offshore development where the next expansion, WDDM phase VI, was for the addition of the Sequoia field. Although comprising of six wells, only three, Sequoia North, were associated with WDDM, being connected into the Sapphire, phase III, hub, both from a process and controls aspect.

Within the original WDDM architecture, the phase III, Sapphire hub, umbilical was configured with separate power and communications cables to support future developments in the Sequoia and Saurus reservoir areas. Unfortunately during the early operation of the Sapphire field, one of the umbilical power cables failed, and in order to restore the dual supplies, one of the future cables was utilized. However, the three-well, one manifold North Sequoia expansion was within the original Sapphire control system expansion capacity and was thus easily incorporated into the existing Sapphire network. The process connection was into the Sapphire M2 manifold utilizing an existing expansion connector on the main header.

## Phase VIII: Enter HIPPS

Phase VII added onshore "main" compression and an additional 36in. export line connected by hot-tap to the 26in. Sapphire export pipe line and had no impact on the subsea control system.

The phase VIII expansion of the WDDM field was carried out in two campaigns; VIIIa added nine wells and three manifolds to the Sapphire and Scarab / Saffron areas and VIIIb added a further eight wells, two with high integrity pressure protection systems (HIPPS), and one manifold to the Simian area. This spread the wells, across both control system vendors, and in theory exceeded the original design capacity. Field expansion has brought in new, higher pressure, reservoirs requiring HIPPS to protect the existing pipe line infrastructure.

Where possible, the system has used common designs throughout the development of the field. And in the case of the Sapphire area, which is 24km from the platform, has the same power supplies as installed for Simian, 52km from the platform. This commonality would allow the control system for the Sapphire field to be expanded to power, and control, the additional wells and manifold that would be associated with the Scarab area, 46km from the platform via this route.

Analysis indicated that changing the topside, platform location, power transformers, using actual data, managing sensors and revising the subsea distribution would provide an acceptable level of system availability.

Process expansion was conventional in that each area remained separate, resulting in the Scarab field being controlled through two different control systems interfacing to the plant integrated control and safety system, requiring various process and field area shutdowns to be included in both subsea systems.

Phase VIII would also be the first expansion for the Simian area, meaning that original design expansion would still be available. Although expansion of the process was conventional with regards to architecture, the new wells brought in new, higher pressure, reservoirs which necessitated the addition of the HIPPS.

## Process network expansion

Although phase VIII had maximized the system from the control systems aspect, there was still a need to expand the process network, with phase IXa requiring the incorporation of a further 16 wells, nine requiring HIPPS, and the associated infrastructure to maintain the production plateau.

Expansion of the process network has been straight forward with only one additional manifold being required. However, the expansion of the control system required significant upgrade.

Conceptual studies indicated that the most cost effective option was to utilize the unused Saurus equipment on the platform and install a new umbilical to the field at the Scarab area and to reconfigure the subsea distribution to balance out both power and communications distribution.

## Future developments

Studies are in place for a tie in of the BP West Nile Delta Libra-Taurus fields; demonstrating that Burullus, and its operator, continue to support the development of new supplies of energy for the Egyptian domestic market. OE

***David Smith** joined the subsea controls industry in 1991, following 15 years in the defense sector. He was involved with the development of control systems for several Norwegian and UK companies and in 2001 joined INTEC to work on the conceptual subsea controls and umbilical design for the next phase of a major gas development offshore Egypt in the Eastern Mediterranean, and he has been there since working as Group Leader, Control Systems, though from the conceptual phase to commissioning the plant on site in Egypt.*

# Oceangoing giants

**One of *Pioneering Spirit's* engine rooms.** Photos from Allseas.

**Rotterdam was home to three giants of the sea in early March – offshore industry flagships, not least Allseas' newly renamed *Pioneering Spirit*. Elaine Maslin took a tour.**

Rotterdam is used to large vessels. One of the largest ports in the world, it is regularly home to the world's largest container ships.

However, even they have been challenged in scale by Allseas' *Pioneering Spirit*, previously named *Pieter Schelte*, after Allseas founder Edward Heerema's father.

At 382m-long, the *Pioneering Spirit* is close in length to the world's largest container ship, the 400m-long CSCL Globe. However, at 124m-wide, to enable its topsides lifting functionality, the twin-hull *Pioneering Spirit* is more than double the *CSCL*'s 58.6m width.

The vessel's inauguration in Rotterdam, late February, marked the culmination of nearly three decades' work. The icing on the cake was a three-platform lifting contract with Statoil on the Johan Sverdrup development, signed the night before the inauguration and announced on the day by Allseas' founder Edward

## *Lewek Constellation*

Meanwhile, on 1 March, EMAS AMC officially christened and named its flagship, the *Lewek Constellation,* prior to her departure to the Gulf of Mexico to start work for Noble Energy.

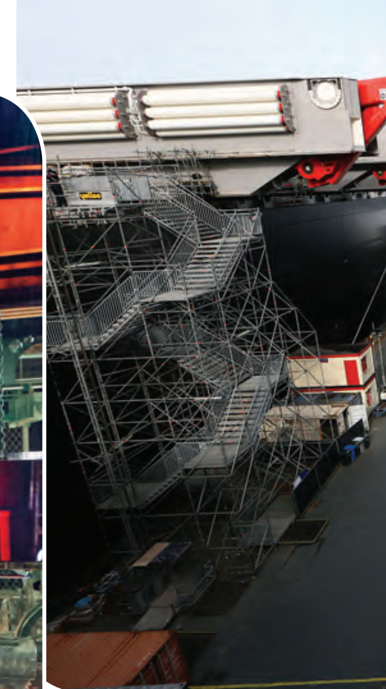
The *Lewek Constellation*, an ice-classed, multi-lay offshore construction vessel with ultra-deep water pipe laying and heavy lift capabilities was initially conceptualized in 2009 and her hull launched in 2012 (*OE: May 2013*).

The 178.27m-long, 46m-wide vessel is designed to deliver complex projects in more than 3000m water depth. According to EMAS AMC, the vessel is one of only two vessels in the world in her class achieving the highest environmental and comfort notations, with an ice-classed hull capable of transiting through 0.8m of ice, plus an advanced DP3 system.

The *Lewek Constellation* has an 800-tonne Huisman multi-lay system, including a tower which can tilt from 60° to 90°, able to support both rigid and non-rigid pipelines, a 3000-tonne Huisman offshore heavy lift crane at the stern of the vessel, two Schilling workclass remotely operated vehicles (WROVs) and a portable reel system which reduces mobilization time.

The portable reel system, which uses a spooling barge to transfer reeled product to the vessel on, allows the vessel to work in field, or in close vicinity, taking reeling operations off the critical path. •


**EMAS AMC's *Lewek Constellation*.** Photo by OE staff.

***Pioneering Spirit*'s inauguration paid tribute to Edward Heerema's father, Pieter Schetle.** Photos from Allseas.

Heerema, who has driven the vision for the vessel.

"My father taught to always think outside the box, to tread beyond the beaten path," said Edward Heerema, during the inauguration on a specially adapted barge installed between the vessel's twin hull lifting slot, reflecting on how his father had introduced innovations to the industry, including the semisubmersible crane vessels *Balder* and *Hermod*. "They were ahead of their time," Heerema said. "When you have vision you have to have courage to pursue it boldly and relentlessly and you have to build on speculation. You can have a nice design but you are not going to get a contract based on a nice design."

On the sidelines of the inauguration, Allseas also named what will become its second mega-lift vessel, *Amazing Grace*, which is planned to be able to lift 72,000-tonne topsides, compared to the *Pioneering Spirit*'s 48,000-tonne capacity. *Amazing*

## *Island Performer* docks in New Orleans

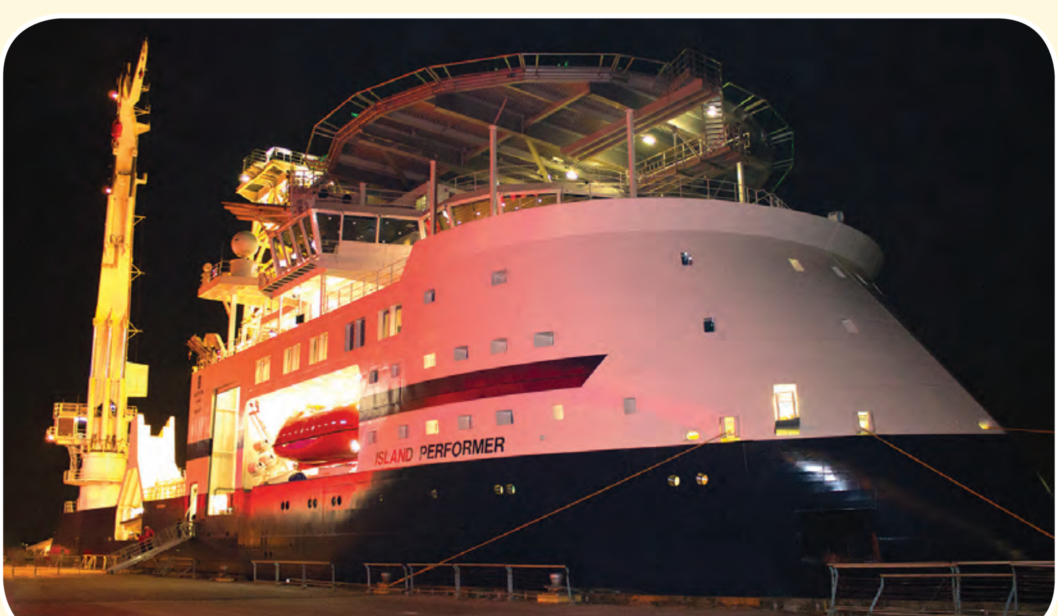
As the last throes of winter ushered in the grey, misty weather upon the mighty Mississippi River in early March, a soon to be familiar visitor in the Gulf of Mexico sat docked at the Port of New Orleans, Island Offshore's newbuild subsea support vessel *Island Performer*.

Built in 2014, the vessel is under a five-year contract with FTO Services, a joint venture between FMC Technologies and Edison Chouest Offshore, in the Gulf of Mexico.

The *Island Performer*, which recently completed its first job investigating the sea bottom in Norway, hoped to drum up local business while in town, and laissez les bon temps rouler (let the good times roll), as the locals say.

The vessel has been equipped with a new deepwater riserless light well intervention stack from FMC Technologies, which enables the vessel to carry out well interventions at depths of up to 6500ft (2000m) and pressures of 10,000psi. The intervention tower sits just over the 8m x 8m moon pool, which is over the ship's center of gravity.

The *Island Performer* is an Ulstein-designed SX121 model, built by the Ulstein




**The *Island Performer* at the Port of New Orleans.**
Photos from FMC Technologies.

***Pioneering Spirit*'s lifting beams loom from its bows.**

*Grace*, expected to cost more than €3 billion, is due to be delivered in 2021, but Allseas has yet to choose a fabrication yard, Edward Heerema said.

"She has to be able to lift the heaviest, the widest and the largest topsides in the world," he said, such as Troll, Sleipner, Gullfaks and Magnus in the North Sea. "She will be similar to *Pioneering Spirit*, having two bows on a big single ship, but the lifting method will be slightly different," he said, suggesting an evolution of the *Pioneering Spirit*'s design. "We are excited about the idea we have, but it is still a fluid design."

*Pioneering Spirit* 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 48,000-tonne (53,000 short tons) for topsides and 25,000-tonne (27,500 short tons) for jackets.

Installation of the jacket lifting equipment has been delayed, but will be installed in time to lift the jacket on Shell's Brent Alpha platform, which is part of a multi-platform lifting contract Allseas has with Shell on the Brents. The vessel's pipelay stinger has been fabricated and is in Vlissingen, Netherlands, ready to be installed.

For Statoil, the *Pioneering Spirit* will install three topsides (ca.26,000-ton production platform, ca.25,000-tonne drilling platform and 19,500-tonne living quarters) and interconnecting bridges on Johan Sverdrup in 2018 and 2019.

The vessel, which will remain in Rotterdam for the completion of the installation of its eight twin sets of lifting beams, already has contracts with Shell and Talisman for single lift and decommissioning jobs, all secured ahead of its final completion.

Heerema said the development of the vessel had been a "roller coaster ride" with the designers, builders, and those who had to secure contracts for the vessel. Initially, Allseas had planned to use two very large crude carriers to create the vessel, which would have been anchored to perform operations. But after some consideration a newbuild, DP vessel, with more complex motion compensation was chosen, using Daewoo Shipbuilding & Marine Engineering in Korea.

The first job for the *Pioneering Spirit* will be lifting off Talisman's doomed Yme topsides in the Norwegian North Sea.

Verft shipyard. It is a DP3 vessel measuring 427ft (130m) long, and it comes equipped with a 250-tonne active heave compensated crane with below deck winch.

It also comes with two UHD deep-sea ROVs provided by C-Innovation. ROV operators, working in 12-hour shifts, can view operations from a comfortable control room onboard. A trainer with C-Innovation said that operators meticulously log information about the wells, whether they've worked on a specific piece or not to ensure proper documentation for future planning purposes.

During a tour of the vessel, an FTO spokesman said that in the event that the vessel begins to shift during operations, the stack is designed to shear off the tool and seal the well.

In addition to well intervention work, the *Island Performer* can also undertake installation and commissioning activities, acid stimulation, scale treatment, hydrate remediation, and inspection, maintenance, and repair (IMR) work.

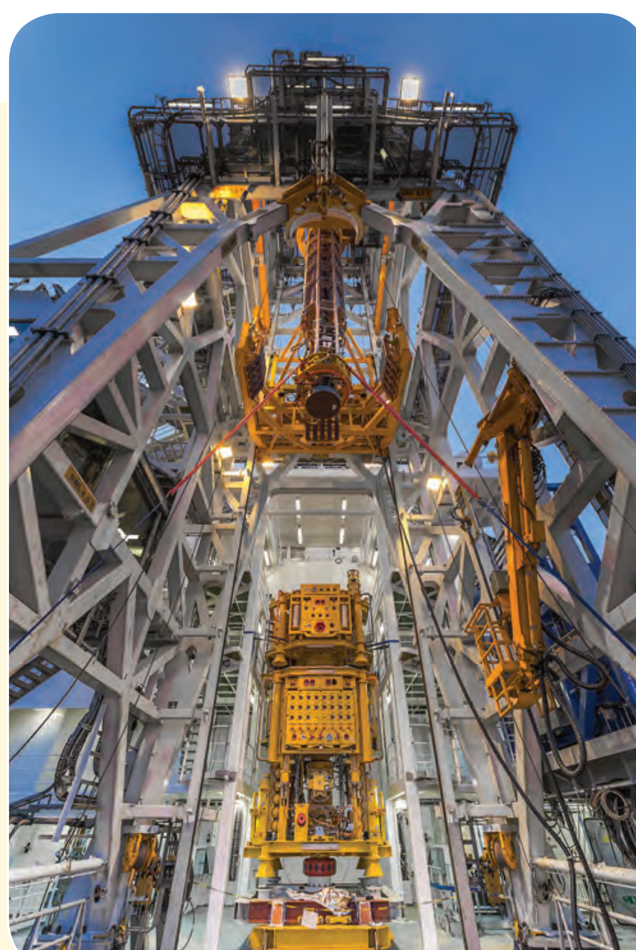
The *Island Performer* is a Norwegian comfort class vessel with accommodations for 130. The interior of the vessel impressively cuts down much of the noise pollution and vibration from its diesel electric propulsion system. ■

—***Audrey Leon***

FURTHER **READING**

www.oedigital.com/oe-media/oe-videos/item/6125-ulstein-unveils-island-performer

www.oedigital.com/component/k2/item/6328-intervention-allies



**FMC Technologies' deepwater intervention stack on board the *Island Performer*.**

**Ceona's *Ceona Amazon* at Huisman Equipment's facility in Schiedam, Netherlands.**
Photo from Ceona Offshore.

Before that, the vessel will perform test lifts in the southern North Sea, using a specially fabricated test platform, based on the module support platform of the former North West Hutton platform.

After Yme, *Pioneering Spirit* will start a project with Shell, removing the Brent platforms. The first will be Brent Delta in May next year. The vessel had been due to work on the South Stream project, but the project has been deferred.

### *Ceona Amazon*

Meanwhile, Ceona Offshore's deepwater multi-purpose *Ceona Amazon* recently left Huisman Equipment's yard in Schiedam and will this summer undertake its first job in record time from drawing board to mobilization. The contract for the construction of the vessel was signed in July 2013, just over a year after the company was formed, and 20 months later the vessel will be delivered complete, thanks to using existing designs and not being tempted to change them through the build, says Ceona.

For its first job, the 199.4m-long and 32.2m-wide *Ceona Amazon,* built by Lloyd Werft in Bremerhaven, will work on the Coelacanth Export Pipelines project for Walter Oil & Gas in the US Gulf of Mexico. The project involves installation of rigid oil and gas export lines, as well as pipeline end termination structures, to tie the new Coelacanth platform into existing pipeline infrastructure, all in a single mobilization.

The *Ceona Amazon's* hull is based on an existing Huisman hull design – already used for the *Noble Globetrotter I* and *II* drilling units. The vessel has a G-lay pipelay configuration. For rigid pipelay, the on-deck firing line will be used with a lay function similar to S-lay. Instead of going over the stern, it will deflect around the stern wheel, with 75-tonne in-line tensioner, then midships vertical lay tower before going vertically, or up to 30% from vertical, down, with the vessel steaming stern-wards.

The Huisman-built 600-tonne deepwater pipelay system, incorporating a 62m-high vertical lay tower, including two four-track retractable tensioners for rigid, flexibles and umbilicals, was installed at the firm's Schiedam facility earlier this year.

The span between the VLS and the 18m-diameter stern wheel is some 112m, wider than any competitors. But Ceona says it has done extensive work on the potential for vortex induced vibration and motion and says the effects are negligible.

The vessel also has two 400-tonne active heave compensated (AHC) masthead cranes, which can work in tandem lifting mode to lift structures down 3000m water depth, and a 30-tonne AHC knuckle boom crane, 4600sq m deck area, two Schilling UHDIII 250Hp work class ROVs, operated by ROVOP, and accommodation for up to 200 people. It can store up to 9500-tonne in its three holds, including a 3500-tonne carousel the firm is planning.

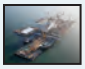
A 199m-long modular, on deck firing spread is due to be installed ahead of the vessel's contract with Walter Oil & Gas. Ceona also has a reel drive ordered for the vessel, currently in Maritime Development's yard in Peterhead, which may be mobilized on to the vessel for a contract with Bennu Oil & Gas (which bought the US assets of ATP Oil & Gas when that company went into administration) on the 4000ft deep water Mirage tie-back project to the Titan production facility in the Mississippi Canyon lease area of the US Gulf of Mexico.

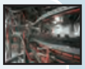
The *Ceona Amazon* is currently Ceona's fourth vessel, alongside the *Polar Onyx* (chartered from GC Rieber under a five-year deal which started last year), which has been working offshore Brazil performing deepwater flexibles installation for Petrobras, and the *Normand Pacific* (on charter from Solstad), which is working for ENI offshore Nigeria on subsea umbilicals, risers and flowlines projects. However, the *Normand Pacific* is due to go off hire in May/June. Ceona decided not to renew the charter due to the current market environment.

Ceona has been in discussions about expanding its fleet, however, short-term, the firm has not made any firm decisions, pending the current market, says Grant Dewbre, vice president business development. "We see overall market conditions in long run as being healthy and improving so definitely fleet expansion is something we will be looking at." **OE**

**VIDEO**: See the *Ceona Amazon. Scan the code or go to:* oedigital.com/oe-media/oe-videos/item/8356-the-ceona-amazon

**PHOTO GALLERY**: OE was given a tour around the *Pioneering Spirit*. View our online gallery to see inside this Leviathan. Scan the QR code or go to: oedigital.com/slideshow/2015-04-oceangoing-giants/





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# Resetting the industry

**Exploration and production executives are facing a bleak year with tough budgets – but the mood wasn't all doom and gloom at IP Week. Solutions are being suggested – as Meg Chesshyre reports.**


Yves-Louis Darricarrère, Total's president upstream

Escalating cost facing the global upstream sector was a recurring theme in presentations on the challenges facing new exploration and production developments during the Energy Institute's International Petroleum (IP) Week in London this spring.

"In recent years the complexity and the scale of exploration activities have resulted in tremendous cost pressures in the industry in terms of both operating cost and capital expenditure," said John Martin, senior vice president, World Petroleum Council, who chaired the event. "The recent postponement of many large projects, which were rendered uneconomic, seems to me at least, to be more driven by the scale of the capex involved rather than the current low commodity prices."

**Tullow Oil's exploration director, Dr Angus McCoss**
Images from the Energy Institute.

"Today costs have become unacceptably high," agreed Yves-Louis Darricarrère, Total's president upstream. "A number of projects have been postponed, redefined, suspended or even stopped worldwide… Our industry has to react. Total is no exception. In 2015, we will accelerate and deepen the major group-wide cost-cutting initiative launched last year. We plan to reduce operating expenditure by US$1.2 billion; the capital expenditure by 10% from $26 billion in 2014." Total has also announced that it plans to reduce its exploration budget by 30%.

Darricarrère cited Total's Edradour project, west of Shetland, as a recent example of creating value through cost reduction and capital discipline. Total had been able to cut the initial cost by a third. Edradour is a subsea tie-back to the Laggan-Tormore development.

"Until 2011, the steady increase in the prices of crude oil

# Quick stats

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

## New discoveries announced

| Depth range | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|
| Shallow (<500m) | 74 | 74 | 68 | 6 |
| Deep (500-1500m) | 23 | 19 | 25 | 3 |
| Ultradeep (>1500m) | 36 | 34 | 12 | 2 |
| **Total** | **133** | **127** | **105** | **11** |
| Start of 2015 | 135 | 125 | 90 | - |
| date comparison | -2 | 2 | 15 | 22 |

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

## Reserves in the Golden Triangle

by water depth 2015-19

| Water depth | Field numbers | Liquid reserves (mmbbl) | Gas reserves (bcf) |
|---|---|---|---|
| **Brazil** | | | |
| Shallow | 9 | 177.75 | 2363.28 |
| Deep | 16 | 1616.00 | 2935.00 |
| Ultradeep | 50 | 15,840.25 | 19,173.00 |
| **United States** | | | |
| Shallow | 16 | 101.80 | 254 |
| Deep | 17 | 919.27 | 1280.48 |
| Ultradeep | 25 | 3456.50 | 3870.00 |
| **West Africa** | | | |
| Shallow | 135 | 4014.32 | 17,802.62 |
| Deep | 43 | 5652.50 | 7840.00 |
| Ultradeep | 15 | 1780.00 | 2610.00 |
| **Total** | **326** | **33,558.39** | **58,128.38** |
| (last month) | (384) | (35,845.89) | (66,717.81) |

## Greenfield reserves

2015-19

| Water depth | Field numbers | Liquid reserves (mmbbl) | Gas reserves (bcf) |
|---|---|---|---|
| Shallow | 1067 | 43,896.82 | 598,706.60 |
| (last month) | (1177) | 45,074.12) | (628,316.23) |
| Deep | 155 | 10,066.24 | 117,233.91 |
| (last month) | (161) | (10,853.24) | (120,623.91) |
| Ultradeep | 100 | 21,419.75 | 40,420.00 |
| (last month) | (104) | (22,227.75) | (40,850.00) |
| **Total** | **1,322** | **75,382.81** | **756,360.51** |

## Pipelines

(operational and 2015 onwards)

| | (km) | (last month) |
|---|---|---|
| **<8in.** | | |
| Operational/ installed | 41,063 | (41,232) |
| Planned/ possible | 24,538 | (24,574) |
| | **65,601** | (65,806) |
| **8-16in.** | | |
| Operational/ installed | 81,682 | (81,420) |
| Planned/ possible | 48,705 | (48,923) |
| | **130,387** | (130,343) |
| **>16in.** | | |
| Operational/ installed | 92,532 | (92,627) |
| Planned/ possible | 40,514 | (39,767) |
| | **133,046** | (132,394) |

## Production systems worldwide

(operational and 2015 onwards)

| **Floaters** | | (last month) |
|---|---|---|
| Operational | 266 | (286) |
| Under development | 50 | (46) |
| Planned/possible | 325 | (336) |
| | **641** | (668) |
| **Fixed platforms** | | |
| Operational | 9283 | (9299) |
| Under development | 91 | (85) |
| Planned/possible | 1347 | (1370) |
| | **10,721** | (10,754) |
| **Subsea wells** | | |
| Operational | 4766 | (4783) |
| Under development | 408 | (378) |
| Planned/possible | 6522 | (6564) |
| | **11,696** | (11,725) |

## Global offshore reserves (mmboe) onstream by water depth

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|
| Shallow | 23,731.56 | 14,241.40 | 41,352.36 | 31,784.66 | 19,583.11 | 29,703.18 | 27,038.55 |
| (last month) | (23,763.00) | (20,900.41) | (36,692.73) | (33,428.02) | (24,440.98) | (29,310.48) | (31,987.18) |
| Deep | 480.55 | 4445.73 | 4375.97 | 3350.29 | 3225.33 | 6826.04 | 12,997.59 |
| (last month) | (481.00) | (4445.73) | (4375.97) | (3475.55) | (3155.96) | (6765.81) | (14,386.51) |
| Ultradeep | 2928.44 | 2347.31 | 2116.71 | 4504.55 | 4724.69 | 8233.33 | 8966.89 |
| (last month) | (2928.00) | (2368.31) | (2202.73) | (6182.92) | (6149.47) | (5053.15) | (9841.71) |
| **Total** | **27,140.55** | **21,034.44** | **47,845.04** | **39,639.50** | **27,533.13** | **44,762.55** | **49,003.03** |

14 March 2015

**Malcolm Brown, executive vice-president, exploration, BG Group**

offset rising costs," he said, "but with prices at a standstill from 2011 to mid-2014 and today, with the sharp drop in the last months, there is no longer any offsetting. Cost inflation has contributed to a significant erosion of operating margins and project returns in our industry."

Darricarrère said that all Total's assets were being scrutinized, including projects currently in the development phase and even more so those under study.

"We are operating at 60% efficiency," commented Antoine Rostand, managing director, Schlumberger Business Consulting." There is no other industry in the world that can operate at 60%." Rostand also said that despite having the largest computers outside the defence industry, the technology was out of date. "We are using technology of the 1990s to design our platforms and fields."

The upstream industry needs to look for less complex and shallower plays, urged Tullow Oil's exploration director, Angus McCoss. The onus "falls upon ourselves as frontier explorers to look for frontier plays which are less complex, plays with which there is a higher resource density of light oil that is easily produced in shallower water," he said.

"We're using advanced seismic methods to look into the shelf edge, and to look at some of the plays that might have been overlooked by the first pass over the shelf," he added. "The industry has worked over the shelf and moved out to deepwater, but we contest that there are still low cost, highly profitable plays to be had on the shelf edge break, and indeed onshore." There had been great progress in the use of seismic inversion, he added, and "innovative use of seismic inversion methodologies, which allow us to locate the hidden upside within our global assets."

McCoss described 2014 as a year of reset in the industry, which has continued into 2015. "We would suggest that you can actually attempt to find oil in simpler geologies, keep the

**Antoine Rostand, managing director, Schlumberger Business Consulting**

complexity down, keep the margin down, and keep that profitability in sight." This type of oilfield was already being looked for in the 1950s, but the industry now had the advantage of new technologies and collective knowledge, so that it was still possible to look for simpler plays despite it being 2015.

The need to continue to pursue frontier plays was emphasized by Malcolm Brown, executive vice-president, exploration, BG Group. "I recognize that frontier plays are not top of the list for many companies in today's oil environment, but in 10 years time they will be. We need 10 years lead time."

The first requirement was innovative thinking. "We need to challenge accepted wisdom. Can there be things where we thought there weren't before?" He cited some examples of BG successes in the Nile Delta, in the Santos Basin offshore Brazil and onshore Bolivia.

He also called for increased use of 3D and longer licensing terms. "We've had 3D for quite a long time, but we haven't had 3D basin-wide over many basins in the world at all, and that's really where you need to reduce the risk before you go any further." **OE**

FURTHER **READING**

**Bracing for bankruptcy** Many companies are reducing expenses to keep costs down, but some are faltering under the low oil price. Scan the code for more or go to: www.oedigital.com/component/k2/item/8426-bracing-for-bankruptcy

# Rig stats

## Worldwide

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 114 | 90 | 24 | 78% |
| Jackup | 418 | 345 | 73 | 82% |
| Semisub | 174 | 150 | 24 | 86% |
| Tenders | 32 | 22 | 10 | 68% |
| **Total** | 738 | 607 | 131 | 82% |

## Gulf of Mexico

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 37 | 32 | 5 | 86% |
| Jackup | 79 | 60 | 19 | 75% |
| Semisub | 27 | 19 | 8 | 70% |
| Tenders | N/A | N/A | N/A | N/A |
| **Total** | 143 | 111 | 32 | 77% |

## Asia Pacific

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 15 | 8 | 7 | 53% |
| Jackup | 118 | 101 | 17 | 85% |
| Semisub | 37 | 28 | 9 | 75% |
| Tenders | 22 | 12 | 10 | 54% |
| **Total** | 192 | 149 | 43 | 77% |

## Latin America

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 27 | 26 | 1 | 96% |
| Jackup | 10 | 7 | 3 | 70% |
| Semisub | 34 | 32 | 2 | 94% |
| Tenders | 2 | 2 | 0 | 100% |
| **Total** | 73 | 67 | 6 | 91% |

## Northwest European Continental Shelf

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 1 | 0 | 1 | 0% |
| Jackup | 52 | 48 | 4 | 92% |
| Semisub | 46 | 43 | 3 | 93% |
| Tenders | N/A | N/A | N/A | N/A |
| **Total** | 99 | 91 | 8 | 91% |

## Middle East & Caspian Sea

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 1 | 0 | 1 | 0% |
| Jackup | 110 | 91 | 19 | 82% |
| Semisub | 3 | 3 | 0 | 100% |
| Tenders | N/A | N/A | N/A | N/A |
| **Total** | 114 | 94 | 20 | 82% |

## Sub-Saharan Africa

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 26 | 20 | 6 | 76% |
| Jackup | 25 | 19 | 6 | 76% |
| Semisub | 14 | 14 | 0 | 100% |
| Tenders | 8 | 8 | 0 | 100% |
| **Total** | 73 | 61 | 12 | 83% |

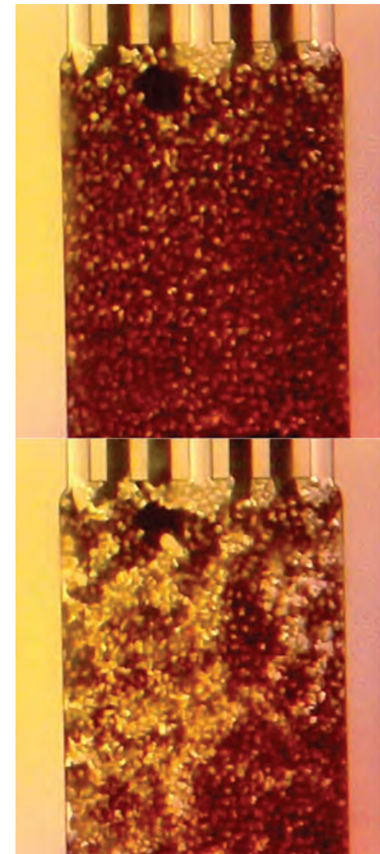
## Rest of the World

| Rig Type | Total Rigs | Contracted | Available | Utilization |
|---|---|---|---|---|
| Drillship | 6 | 3 | 3 | 50% |
| Jackup | 24 | 19 | 5 | 79% |
| Semisub | 13 | 11 | 2 | 84% |
| Tenders | N/A | N/A | N/A | N/A |
| **Total** | 43 | 33 | 10 | 76% |

Source: InfieldRigs

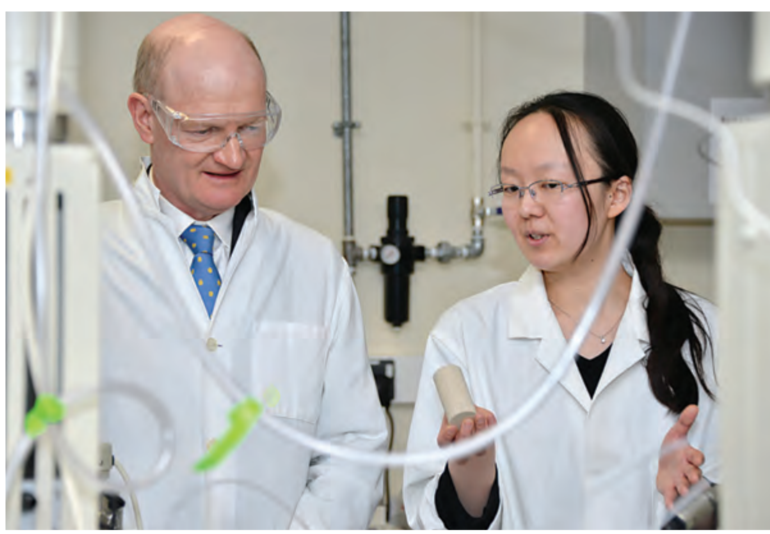
17 March 2015

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



# Understanding EOR

**EOR is taking off offshore, yet scientists at the University of Aberdeen believe more work needs to be done to understand the link between reservoir properties such as wettability and fluid flow to help in order to truly benefit from EOR, Elaine Malin reports.**



**Prof Yukie Tanino (right) in the University of Aberdeen's laboratory.**
Images from the University of Aberdeen

Enhanced oil recovery is playing an increasing role in the global offshore production environment.

With a portfolio of increasingly mature fields, operators have been seeking to increase recovery rates, from around 20% to upwards of 60% and higher as enhanced oil recovery (EOR) methods and technologies improve and reservoir understanding increases.

Increasing recovery rates could have a dramatic effect on global reserves. According to Shell's 2014 Enhanced Oil Recovery report, "Just a 1% increase in the global efficiency of hydrocarbon recovery would raise conventional oil reserves by up to 88 billion bbls, which is the equivalent to three years of annual production at today's level."

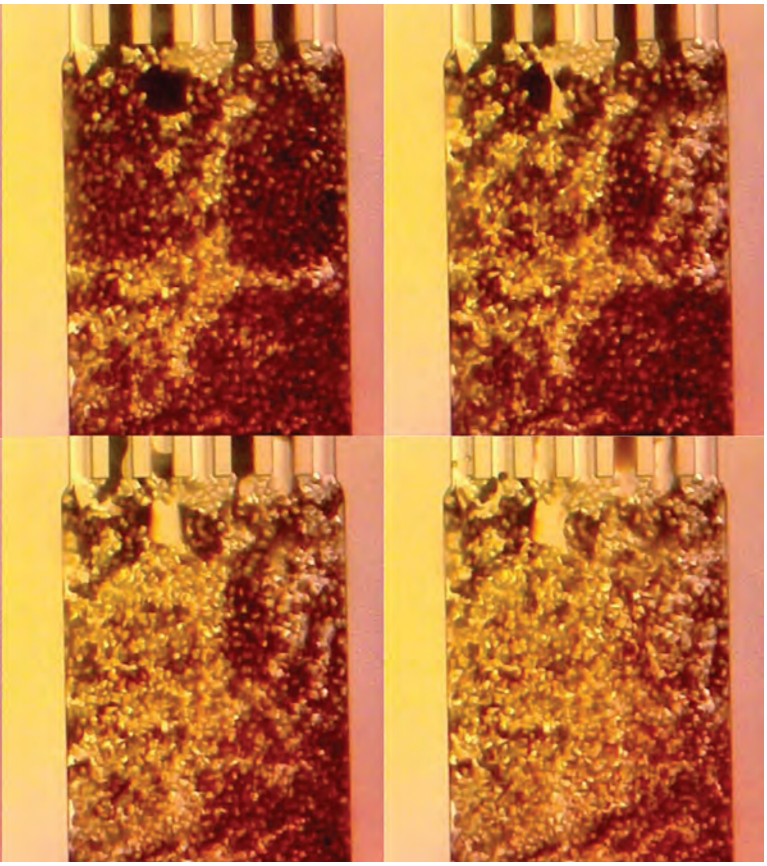
EOR methods range from waterflooding (including smart water or low salinity water technologies), miscible gas floods, and polymer flood. $CO_2$ injection for EOR and storage is also being considered.

However, while these technologies have been developed by oil companies, and have been deployed already, trialed or due to be trialed, scientists at the University of Aberdeen believe that more work needs to be done to understand the link between fundamental reservoir properties, specifically wettability, and fluid flow, which in turn impact how well EOR methods work.

What's more, they're also looking at how oils with different chemical compositions interact with rocks of different compositions to influence reservoir wettability.

It's complex work, but understanding the fundamentals will help the industry to understand why what they're doing works – or not, says Dr. Yukie Tanino, lecturer at the university in the Environmental & Industrial Fluid Mechanics Group in the School of Engineering."What is the optimal reservoir wettability for oil recovery," she asks. "Once we can answer that we can think about how we can achieve that wettability using conventional EOR methods."

Wettability is key to understanding fluid flow in the reservoir as it controls where fluids are distributed at the pore-scale. Some surfaces repel water (hydrophobic, or "oil-wet") and some repel oil (hydrophilic, or "water-wet"). The university is carrying out corefloods using synthetic oil to simulate different wettability scenarios in the lab.The main focus so far has been on identifying quantitatively correlations between wettability, as characterized by the contact angle of oil-contacted grain surfaces, and waterflood oil recovery. Future work will focus on chemical signatures of wettability inversion during waterfloods.



Examples of samples prepared by the University of Aberdeen.

A further development of the research program at the university has seen Tanino and her colleague Dr. Stephen Bowden in the Department of Geology and Petroleum Geology assembling mm-scale models of reservoirs in microfluidic chips. This approach has two main benefits. First, it provides a petrographic perspective (a geologist's view through a microscope) of what's happening. Second, the small scales of the model reservoir speeds up experiments, permitting a much bigger range of variables to be investigated.

But that sounds like more work – what is the benefit? "The main challenge of laboratory investigations is that there are a number of properties that control oil recovery, and each of these properties can take on a range of values: simply comparing two different rock types, two different oil types, and two different water types at five different temperatures and pressures would require two hundred or more experiments, each lasting one or two months," Tanino says."Just comparing these cases would take my laboratory several years of corefloods at the conventional (cm-) scale!

This isn't practical and so the main benefit of using lab-on-a-chip methods is that it becomes feasible to systematically investigate a wide range of variables."

Bowden says: "One of the first experiments that sprung to mind demonstrated that two comparable oils, with small differences in their chemistry, can exhibit identical waterflood behavior in one rock type, but then differ significantly in another rock type."What's so odd is that the oils are so similar, and in one rock type they did indeed behave in a

# Being economical with EOR

**Consideration is being given to new tax incentives to encourage enhanced oil recovery schemes in the UK North Sea. Elaine Maslin looks at an assessment of EOR economics.**

As production declines, the rate of large new discoveries dwindles, enhanced oil recovery (EOR) schemes are becoming an ever attractive option on the UK Continental Shelf (UKCS).

But are they attractive and could tax incentives help make them more so? A recent report by Professor Alex Kemp and Linda Stephen at the University of Aberdeen compared the economics of three types of EOR and suggests that a tax allowance, based on operating costs, would help make these technologies fly in this mature, expensive basin.

While EOR schemes are already in common use onshore, they are less common offshore, due to the higher implementation costs. But, with an average UKCS recovery rate of about 45%, the potential for EOR could be huge.

The University of Aberdeen's review, under the aegis of the Aberdeen Centre for Research in Energy Economics and Finance, assessed three types of EOR – salinity waterflood, polymer flood and miscible gas injection. The study was conducted ahead of a review of the UKCS tax regime, which could look to introduce tax incentives appropriate for EOR. An announcement on the tax review was due to be made during the UK Chancellor's budget on 18 March, just before OE went to press.

For each model, it was assumed that the EOR project would be undertaken on existing host or mother fields.

### Low salinity waterflood

According to the study, low salinity waterflood involves a substantial initial investment, followed by a modest annual production increase, spread over a very long time period, meaning a long payback period. Operating costs are substantial, the report says, particularly in terms of requirements for manpower and beds offshore.

Key risks of low salinity projects are; the effectiveness of similar way, while in the other case they were so different. To me it seems unfair, but if an operator wasn't aware of this they could easily make erroneous assumptions about future water production rates and overall recovery. This is very interesting for us, but clearly a bad day in the office for an engineer."Nature's final cruel trick is that many fields and reservoirs not only have geological heterogeneity (different rock types), but also a mix of oil types – often because many different charges of petroleum have filled a reservoir."Tanino and her colleagues are assembling a library of these small scale experiments. "The intent is that a user – an engineer, geologist or production chemist – could search the experimental archive and investigate the effects of oil chemistry, rock type, and water composition on wettability to better evaluate EOR options," she says.

"There is a lot of interest now on the effects of changing water chemistry (BP's LowSal, Bright Water and Brackish water, for example). It makes sense if you are injecting water to displace the oil that the consequence of using one or another type of water is considered. We are looking at the issue from the other side of the equation: how will different mineral and oil types in a rock interact with a given water type? This takes us back to the fundamental question of what influences wettability, and then the question of how can changes in wettability – either natural or engineered – impact production?" OE

the waterflood technology in enhancing oil production; the commissioning of the low salinity equipment; the additional complexity of managing the reservoir; and the extra problems regarding well integrity. A further risk relates to the extra weight on the platform from the low salinity kit, which reduces the flexibility of other activities on the platform.

The university assessed a project involving potential EOR of 42 MMbbl, with an estimated £338 million development cost (US$13.3/bbl), at 2014 prices. Lifetime operating costs were estimated at around £100 million and operating costs per barrel at just under $4/bbl.

### Polymer flood

Polymer flood also has a high initial investment cost, including the cost of modifying the FPSO/platform for receipt of polymers, and the costs of building the EOR storage facilities, according to the University of Aberdeen report. Operating costs are also high, because of the need to purchase large amounts of polymer over a long period. In fact, the cost of the polymers may constitute 80%-90% of the total operating costs, the report says. As with low salinity water, the additional production from polymer flood will generally be at modest levels, over a long time, with payback similarly long.

Chemical EOR projects also come with risks, including the extent of degradation of the polymer in the reservoir. There can be degradation of polymer in the chokes, such that the full viscosity is not obtained at the other side of the choke, highlighting the importance of the choice of choke solution, inversion mixer design, and shear resistant polymer solution. There could also be a risk around the long term availability of polymers. Optimally at least 90% availability is needed, the report says.

Professor Alex Kemp

The university modeled two possible outcomes for a polymer flood project, on a risked and unrisked basis. In the risked case, the potential EOR (including sales gas) was around 17.5 MMboe, depending on the economic cut-off. The development cost was estimated at £116 million, at 2014 prices. The unit development cost was estimated at $10.67/boe and the lifetime operating cost was estimated at £454 million, with $41.9/boe operating cost.

In the unrisked model, the potential EOR was estimated at 38.3 MMboe with an estimated £156 million total development cost ($6.6/boe), and £529 million lifetime operating cost ($22.7/boe).

### Miscible gas

Miscible gas also has substantial investment costs and large operating costs, largely due to the need to purchase substantial quantities of gas over a long period, says the report. The biggest risks for a miscible gas scheme are the need for long-term gas supplies and gas prices. The effect of such a scheme would likely be modest levels over a long period, the report says.

In the model used, the potential EOR was around 53.3 MMboe, depending on the economic cut-off, including worthwhile volume of natural gas liquids. The total development costs were estimated at £503.5 million. Lifetime operating costs, including purchase of gas, were estimated at £1,492 million, with $15.5/boe development costs and $4/boe operating costs.

### Economics

Kemp and Stephen modeled how all three of these schemes would fare under different potential tax allowance schemes, including removing entirely the supplementary charge – a tax in addition to corporation tax on profits from oil and gas production.

Even with a US$90/bbl oil price, and 58 pence per therm for gas, used in the modelling, they conclude: "The findings indicate that currently the project investment economics are quite challenging."

Given the high cost of the input product for polymers and gas, an alternative could be to offer a tax break on the cost of polymers, says the report. "Given the very high costs involved in purchasing polymers and gas for schemes which are promising in the context of the UKCS, there is a case for an uplift [operating cost allowance] relating to these product requirements," it says. "They are akin to capital expenditures, when a wider view of their purpose is considered. Even a partial allowance for these costs would be reasonably effective."

The "more radical" approach of removing the supplementary charge from EOR projects was seen to be beneficial, however, operational cost uplift produced a more effective solution, the report concludes. OE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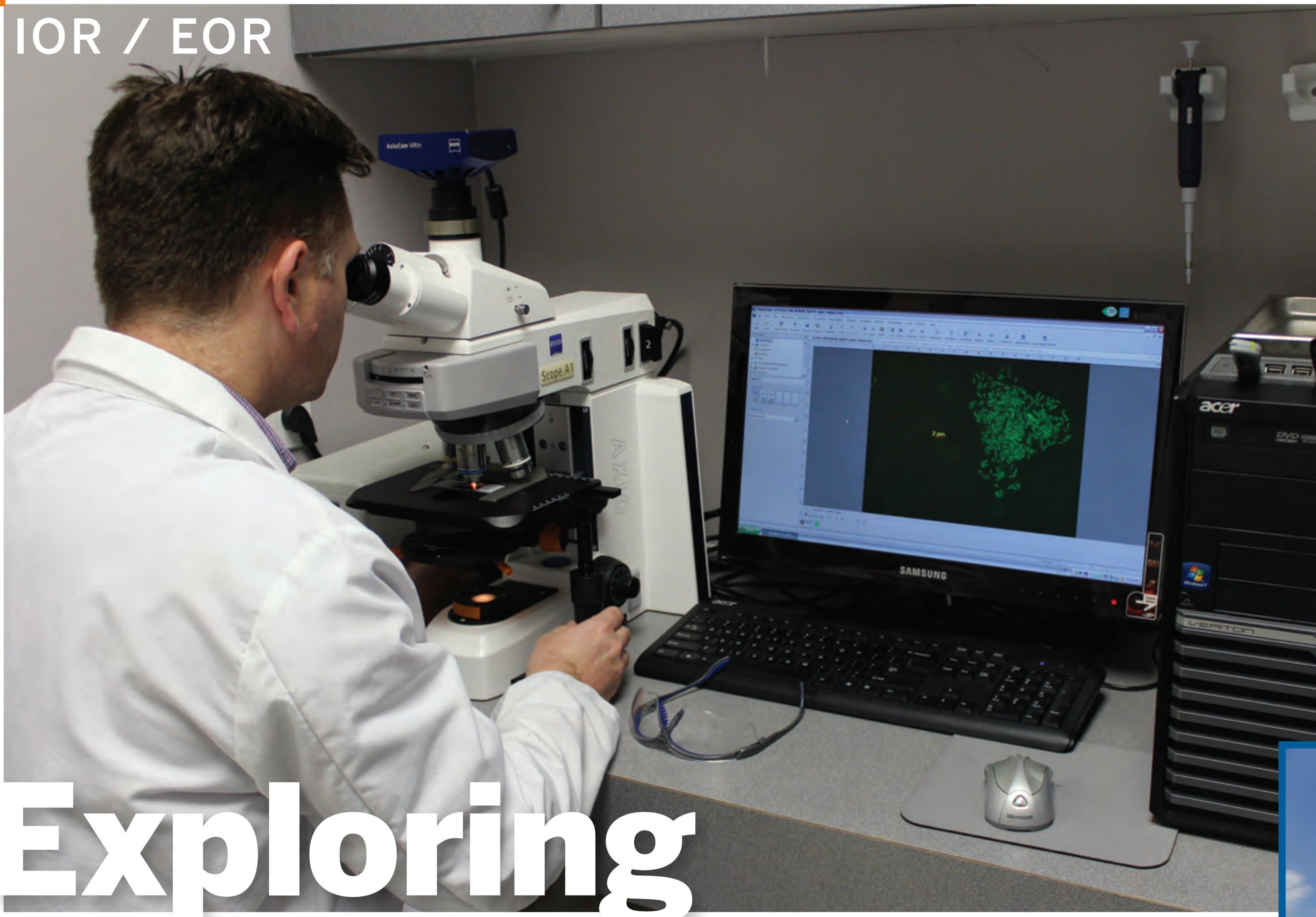



# Exploring MEOR

**Jerry Lee takes a look at some of the research surrounding microbial enhanced oil recovery (MEOR), and how it could be a viable solution for increasing recovery efforts.**

Exploration and new field development can require a considerable amount of CAPEX before the first drop of oil is ever produced. Mature or aging fields, however, have proven oil that is already producing. Thus in this oil economy, it may be more cost effective to turn to these fields and seek methods of increasing recovery and profitability. Enhanced oil recovery (EOR) techniques have been developed for this purpose, to decrease the amount of residual oil in a reservoir.

Microbial enhanced oil recovery (MEOR) is a type of EOR that has been refined over the decades, and with an incremental cost around US$10/bbl, it is cost effective and can be seen as a viable solution for today's oil economy.

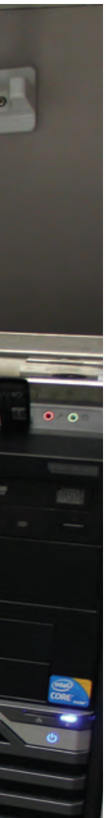
"Low CAPEX and low OPEX means low risk for oil producers, so it's a very attractive technology. In current oil times it may be the only economic alternative, so without a lot of overhead it's going to be the competition in EOR now," says Mike Pavia, CTO of Glori Energy.

MEOR is the process whereby microbes in a reservoir can affect the production in the producer wells by producing gas, acids, surfactant, and change water flow patterns. In the past, efforts have been made to introduce non-indigenous microbes into the reservoir, or feeding the microbes with an external carbon source like molasses. These methods, however, did not take hold. Though from those experiments, current technology has improved to focus on the factors that worked in those experiments and avoiding those that did not.

The focus of contemporary technology is now centered on two factors: bio-surfactants, and induced bio-plugging. The idea behind these two factors are simple; bio-surfactants will allow oil to become more mobile, while bio-plugging facilitates greater access to oil by encouraging the flow path to deviate to underutilized or isolated pathways.

Glori Energy and DuPont are two companies that put these ideas to use by utilizing the tenacious nature of microbes.

Found in the reservoirs are indigenous microorganisms that are inactive or dormant and deprived of nutrients. These hearty microbes have already adapted to the extreme living conditions in the reservoir and thus serve as an affective medium for MEOR technology. Once supplied with the proper nutrients, the microbes become active and multiply. However, not all of the microbes are useful, so a sample of the organisms found in the reservoir must be taken back to the lab where the useful organism can be isolated. From the lab, a nutrient package can be developed to positively select for the useful organism, however, a carbon source is left out that will require the organism to use



**A Glori scientist observes microbial growth and behavior at the company's Houston laboratory.**
Photos from Glori Energy.

the oil in the reservoir as the carbon source. When the nutrient is injected into the reservoir, the useful organism can outcompete the other reservoir flora. Though both companies have their own proprietary nutrient treatment packages, they have similarly focused on nitrate formulas and have stayed away from sulfate formulas.

"Addition of sulfate could encourage oil well souring by sulfate reducing organisms. Therefore, we have restricted ourselves to a limited set of electron acceptors, concentrating mostly on nitrate," says DuPont in a paper, SPE-146483 [1].

## Glori

The Glori AERO System, only involves adding a nutrient package to the existing waterflooding of a candidate well. As a result, there is minimal production disruption and initial results can be seen in 6-12 weeks, Pavia says.

The process begins with the selection of a candidate field: must be a sandstone reservoir undergoing a waterflood, and generally permeability of 100mD or better, pH range between 6-9, temperatures below 200°F, salinity up to 14%, and good conductivity between the injector and producer well.

**Glori Energy's AERO System becomes part of an oil field's existing waterflood infrastructure.**

After selection, a sample of live water is taken so that the reservoir flora can be examined and brought back to the lab where the nutrient package will be developed to enable the growth of the beneficial microbe(s). This package may then be taken to the field where it will be introduced into the existing waterflood, a process that can be repeated as long as the operator desires.

The AERO System is hypothesized to affect two factors within the well to improve recovery:

"Primarily the disruption of interfacial tension and secondary the dynamic growth and death of microbes that change the water flow patterns," Pavia says.

One mechanism, surfactant activity, is hypothesized to affect the oil-water interfacial tension. In order for the organism to access the oil as a carbon source, it must traverse the oil-water interface and bring the oil droplet into the water, releasing the unconsumed oil.

"What we believe happens is that these microbes behave as surfactants themselves, and they change the interfacial tension of the oil-water interface," Pavia says. "The interfacial tension is disrupted and the water pressure squeezes the oil out into the producing well. If the microbes produce the surfactant, than other microbes will eat that surfactant. That's the reason some of the older techniques failed."

The other mechanism of recovery, bio-plugging, is simple and results in improved sweep efficiency. As the nutrients package is added, dormant bio-plugging microbes are activated and replicate.

"The microbes grow on the oil as a carbon source, and as the microbes collect in the pore, the water flow patterns will change. Once that oil is produced, the microbes will go find a new source in another pore and repeat the process, so it's kind of a dynamic," Pavia says.

## DuPont

DuPont field candidates must also be sandstone reservoirs undergoing a waterflood with additional minimum reservoir characteristics: permeability greater than 50mD, pH from 5-9, temperature below about 150°F, salinity less than 9%, oil viscosity greater than 16°API, and well pressure less than 3000psi.

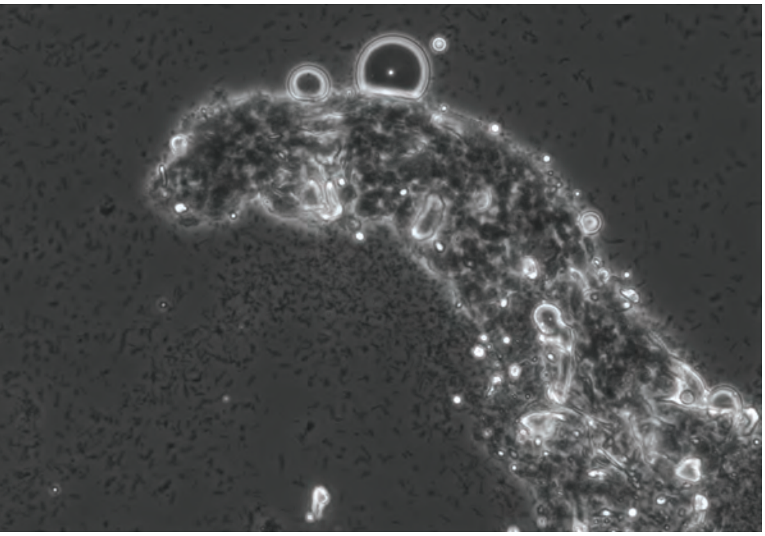
After the candidate field is selected, a sample of live oil is similarly collected and a nutrient package is designed to enable the desired microbe(s) to grow and outcompete the other microorganisms. However, unlike the AERO System, the desired microorganism is cultured in a separate broth that will be used to inoculate the reservoir in the initial phase of the injection process.

The key component to the DuPont MATRx system is the inoculation of the well with the bio-plugging microorganism prior to the addition of the nutrients package.

"Research has shown inoculation to be a critical step necessary to the overall success of MEOR technologies," says DuPont's website. The event follows an injection protocol downhole to help propagate the nutrients and microbe further from the injector, and periodic injection of nutrients to sustain the population. Also, according to DuPont's paper SPE-169549 [2], to maintain the desired microbe's dominance in the reservoir, inoculation is also repeated during the year.

"The increase in injection pressure happened within a few months and was sustained for the duration of the MEOR test. This clearly demonstrates that we have been able to develop significant and sustainable bio-plugging in this reservoir," says DuPont in a paper, SPE-146483 [1], referencing a field test of the MEOR technology. "Oil production has increased in the field by 15-20% with a corresponding reduction in water cut."

Key differences in the proposed mechanisms for improved recovery resulted in significantly different designs in the two technologies.



Phase contrast microscopy is used to visualize microbes and oil in Glori Energy's Houston laboratory.

Glori Energy scientists perform core flooding experiments in the company's Houston laboratory to study the effects of the AERO mechanism.

For the bio-plugging activity, DuPont selects for a microbe that is able to perform a specific EOR function. "That function is the production of an exopolymer as part of a biofilm that reduces the pore throat size and the apparent permeability in watered out channels in the reservoir," says SPE paper 169549 [2].

As the microbe population grows, the production of the biofilm will build up along the pathway and obstruct the pore throats, resulting in the increase of resistance along that path to a point when another pathway will be less energy intensive, and the flow will naturally divert to that path. Thus, the oil found along the new pathway is more readily accessible. This process can also be continually repeated resulting in more of the reservoir's oil being accessed and released. Though both hypotheses have ground, neither can be definitively proved at this time due to the nature of reservoir analysis.

Regarding the interfacial tension between oil and water, DuPont hypothesizes that the organism produces a bio-surfactant that would lower the interfacial tension between oil and water and cause spontaneous emulsification. While a reduction was observed, DuPont research showed that the change in interfacial tension was not great enough to cause spontaneous emulsification. Thus, DuPont's MATRx system focuses on to taking advantage of the bio-plugging activities of the indigenous reservoir microbial organisms.

## Future

Past ventures in MEOR technology did not instill much confidence in the industry; poor baseline data to compare results and poor follow-up impeded the success of some projects, while others failed due to unexpected behavior in the reservoir or did not produce the expected results. However, from those past ventures, the current players in MEOR technology have learned and improved upon the technology making this technique a commercially viable alternative in EOR technologies.

Statoil is currently applying MEOR technology offshore in the Norne field in the Norwegian Sea. Known as activated microbial enhanced oil recovery, the technology has been primarily for offshore use. Glori's AERO System is the result of collaboration between Glori and Statoil. Results from the field are currently being evaluated.

With the fall in oil prices and the cost effectiveness following successful application of MEOR technology, will this technology catch on? Glori's Pavia remains optimistic.

"If you go to someone and propose an EOR project that's going to cost them $60/bbl, they're going to say 'No,' but if you go to them with a technology that can be done at $10/bbl, they may say 'here's a reasonably priced technology that works in this environment,' and when oil rebounds, which we've seen over and over again that it does, this will be a great technology then as well. I think we're still in a reactive stage where everyone is worried about the prices and their budgets for EOR, but I'm optimistic that it will be fine," Pavia says.

Academia shares a similar stance. Saif Al-Bahry, a professor at Sultan Qaboos University in Sultanate of Oman, says that due to aging oil fields, new and inexpensive technologies for EOR are a necessity.

"More research and knowledge on MEOR techniques are needed since understanding MEOR mechanisms in depleted oil wells can be used in wellbore clean up, oil-spill, bioremediation, heavy oil recovery and drilling fluid," Al-Bahry says. "In the next 5-10 years, more research institutions will be involved in MEOR technology, evident by the increase in the number of publications in MEOR and international conferences.

"However, more international conferences related to MEOR are urgently needed to discuss various issues and means to make this technology cheaper and applicable." OE

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# Inflow control

**Reservoir engineers are getting to grips with automatic flow control devices to limit water cut and gas breakthrough – just as they did with their passive forbearers, explain Benn A Voll, Ismarullizam Mohd Ismail, and Iko Oguche.**

One of the limiting factors affecting the length of horizontal wells has been the effective management of reservoir sweep with regards to wellbore influx. The added benefit of greater reservoir contact is met with increased differential drawdown across the well length and a greater tendency to cut across heterogeneous formations with varying permeability.

For many years, inflow control devices (ICDs) which restrict flow by creating additional pressure have been used to mitigate this problem. However, they are passive in nature and once installed cannot be adjusted. In the event of water or gas breaking through in an oil well the limitations of the passive ICD become evident as the well can be quickly overtaken by the breaking fluid.

Autonomous ICDs (AICDs) are, however, self-regulating and are classed as active. Unlike their passive counterparts, which produce greater pressure drop for higher density fluids, AICDs, in addition to controlling oil influx, choke water and gas more readily. This prevents the well from being flooded when unwanted fluids break through, therefore providing the advantage of being able to even out inflow into the well and, in addition, choke compartments producing unwanted fluids leading to greater recovery, lower water cut and gas production.

**Results from Linear Regression Results from Multi-Variable Non-Linear Regression**

| AICD Size: Type "A" | | AICD Size: Type "A" | | Units |
|---|---|---|---|---|
| $a_{AICD}$ | 4.004E-05 | $a_{AICD}$ | 3.554E-05 | Bars/(kg/m³)(m³/day)$^x$) |
| $\mu_{cal}$ | 1.000 | $\mu_{cal}$ | 1.000 | cp |
| $\rho_{cal}$ | 1000 | $\rho_{cal}$ | 1000 | kg/m³ |
| x | 2.559 | x | 2.680 | prop |
| y | 0.694 | y | 0.592 | prop |

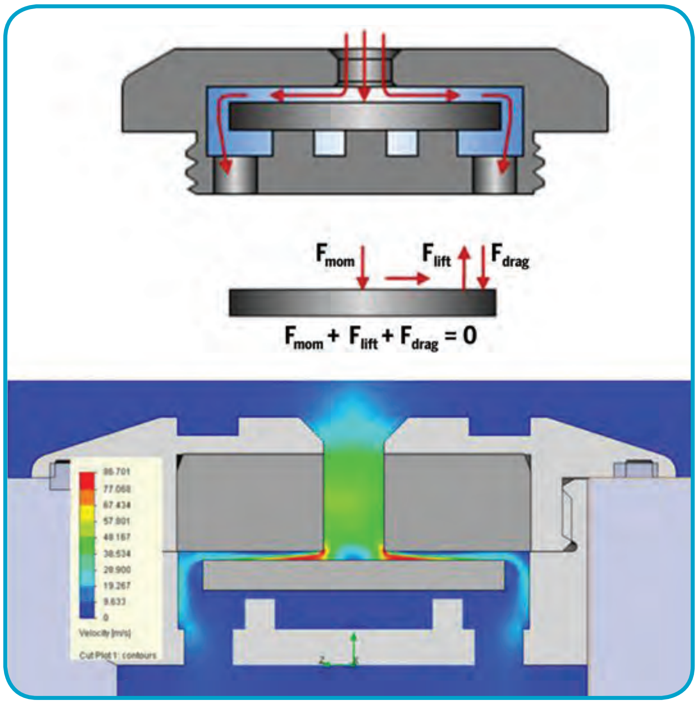



**Fig. 1 – Levitating Disc AICD.** All images from Tendeka.

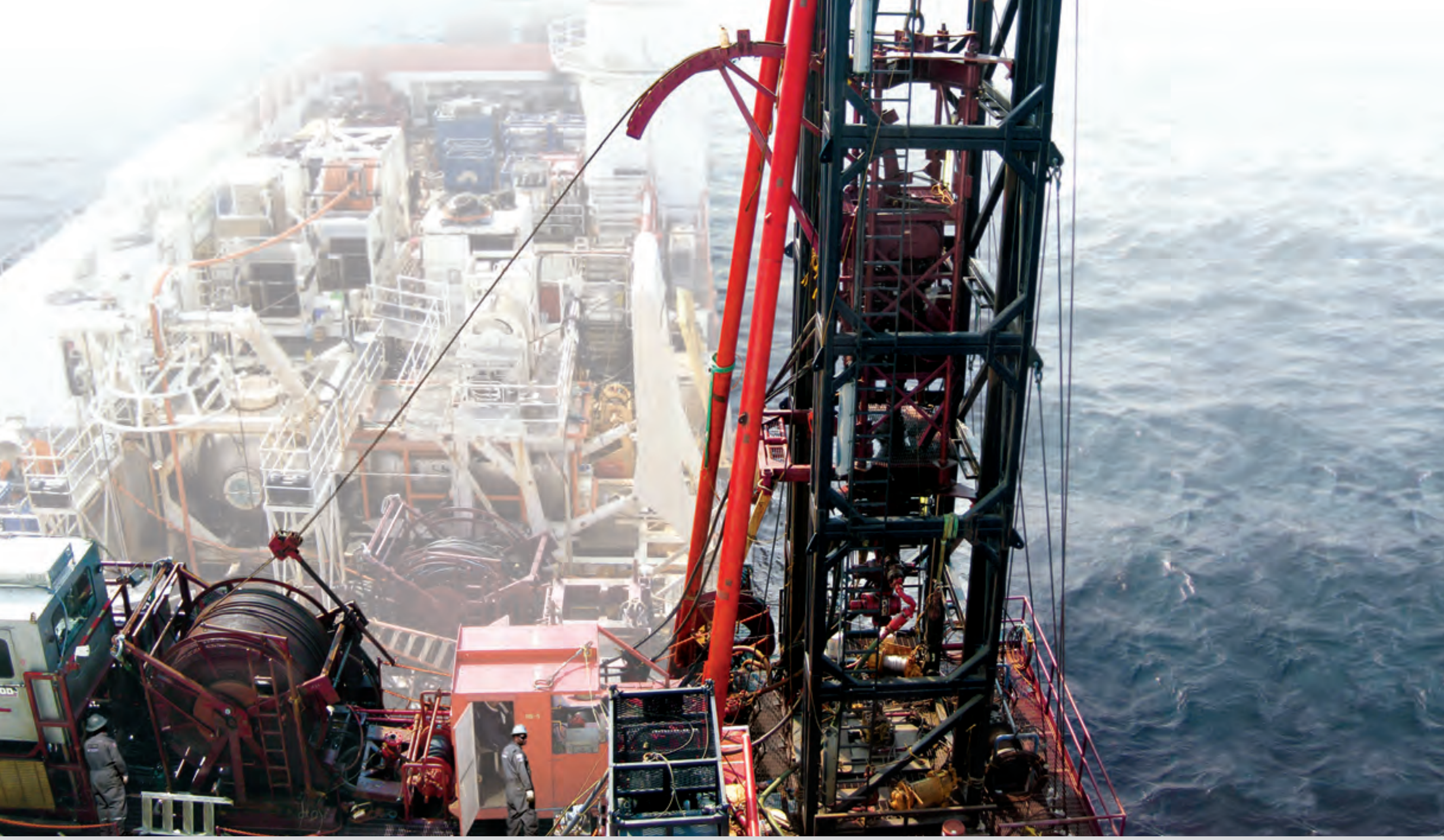
Integral to the effective implementation of AICD technology is optimization of the device and integration into the reservoir completion. Tendeka has developed a multiphase flow model of the AICD performance and applies this to modeling its influence on inflow distribution in a completed well system. The model is validated by comparing results obtained with extensive testing in a multiphase flow loop and actual field examples following the installation of more than 10,000 of the company's AICDs in more than 50 wells globally.

### AICD benefits

One type of AICD available in the industry uses a levitating disc, shown in Figure 1. The disc regulates flow based on the fact that a moving stream of fluid will experience a reduction in pressure. When stream velocity above the disc are high enough, the pressure drop generated will lift the disc and restrict the area available for flow thereby choking the flow. Since the velocity is different for fluids of different viscosities at the same inlet pressures, it chokes fluids of different viscosities differentially.

Improved understanding of autonomous inflow control devices (AICDs) through single and multiphase testing has allowed for the creation of mathematical models making it possible to upscale or downscale these devices for changing conditions. Tendeka has developed a methodology for the creation of performance curves for any downhole fluid properties. A multistep approach for design and optimization of an AICD completion design should be followed including:

- Collation of customer reservoir data and performance requirements
- Design of the AICD to suit the reservoir flow characteristics
- Creation of initial fluid flow



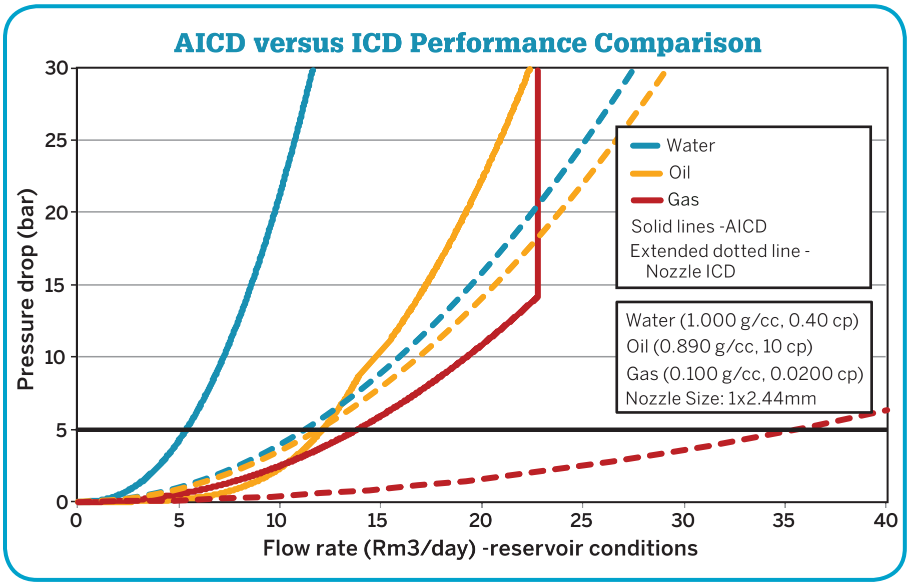



**Fig. 2 – Passive ICD versus AICD comparison plot.**

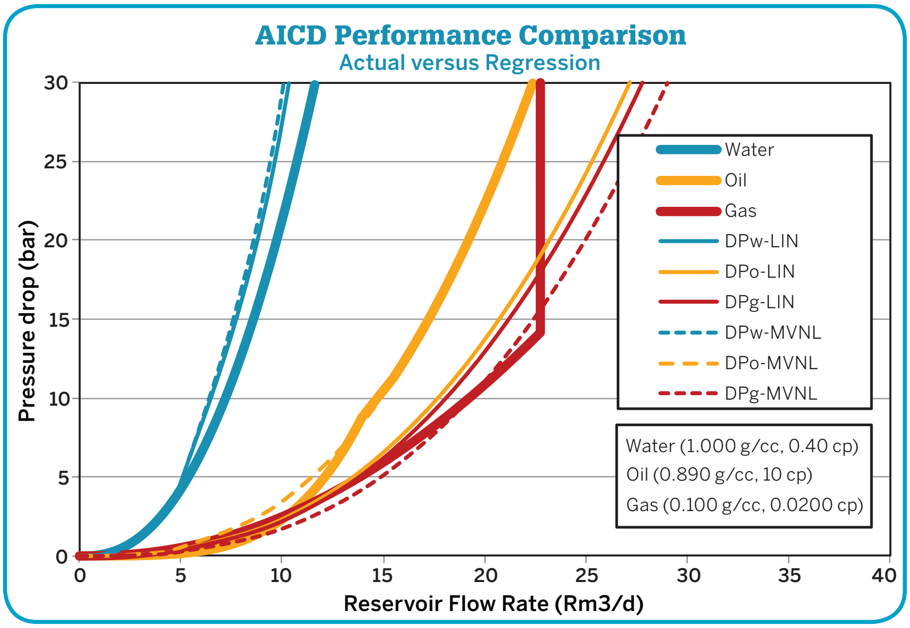



**Fig. 3 – Comparison between test data (thick lines), linear (LIN) and multi-variable non-linear (MVNL) regression.**

performance curves to compare with a passive ICD design

- Generation of AICD performance coefficients for input into linear and non-linear regression simulators
- A quality check of the design's regression coefficients for gas control accuracy.

Typically, the type of customer reservoir data required to create an optimized AICD design is:

- Live oil/gas/water densities and viscosities,
- Expected production rates (oil/gas/water) without ICD completion (initial/mid-life/late-life)
- Initial expected drawdown
- Well length

The data is inputted into the design and simulator software to aid in the creation of an optimum AICD design.

A unified approach to AICD modeling is paramount, and using the original equation proposed by the early adopters should be a first choice. Most AICD providers are able to provide performance curves, and as such should be able to port into existing or proposed simulation matrices.

### Work Flow

Several mathematical equations have been proposed to allow for the simulation of AICDs in reservoir simulators. The most popular and widely implemented was first proposed by Statoil and has since been simplified by Tendeka, but it is of paramount importance to develop field specific coefficients. To arrive at such field specific coefficients, a series of steps must be followed;

**1.** Generate performance data for the specific AICD for the application using a mathematical model developed from empirical testing to present the data as flow rate, mixture density and viscosity and pressure drop.

**2.** Perform multivariable non-linear regression on the dataset to determine optimum coefficient values. Linear regression can also be used by using a logarithmic relationship.

**3.** Provide a simple table for a single unit AICD with the following parameters – see table.

**4.** Comparison with a passive ICD System. As a multitude of passive ICD systems exist in the market place, it is suggested that an equivalent fixed orifice with a discharge coefficient (Cd=0.85) should be used for ease of comparison.

Figure 2 shows a comparison of an AICD versus a passive ICD where oil flow is matched at a desired pressure differential. In this example, the AICD provides water and gas choking 2-3 times better than a passive device. The net effect of this behavior should be studied over the life of the well. The main challenge for reservoir engineers is to have a meaningful adjustment of the AICD control strength over a simple passive ICD. The best way to optimize this is to alter the AICD coefficient by the number of valves used. By altering the strength and nozzle diameter, the two systems can be compared in greater detail.

**5.** Quality check the regression coefficients against test data and choose the best fit coefficient data set

The regression coefficient set should be chosen based on which set gives the best fit for the actual field conditions, i.e. water control versus gas control or both. Usually the Multi-Variable Non-linear Regression (MVNL) method is the most rigorous and gives the best overall match.

The regression curves should be plotted against real test data and compared for both gas and water control accuracy. In Figure 3 (below) MVNL coefficients better match the real test data and would be the choice for future simulations.

**6.** Provide a scalable table of AICD coefficients. This can be used by production /reservoir engineers to hydraulically optimize the completion, either by using reservoir simulators or steady-state hydraulics software

## Conclusions

The methods described above have been successfully implemented to evaluate autonomous versus passive ICDs in several large field developments. Some stability problems were reported in the reservoir simulators and several suggestions have been made on how to improve the stability.

Setting annular flow in the completion annulus to zero when running the reservoir simulator seems to improve stability and create results often verifiable by steady-state simulators like NETool. With ICDs or AICDs, annular flow is zero across the reservoir block such that the error by switching off annular flow can be disregarded. The flowing bottom hole pressure during the life of the well should also be compared to a simple NETool style steady state simulation to ensure the reservoir simulator is in fact calculating the pressured drop correctly.

Unless the bottom hole viscosity of oil and water is the same, an AICD should always outperform a passive ICD system. Ensuring sufficient hydraulics capacity for total liquids over the life of the well is important when running these simulations. As the reservoir engineers become more comfortable with the AICD-coefficients and with the ability to scale up and down for meeting the required flux rate, there should be a major increase in AICD completions, similar to that experienced over the last 20 years with the passive ICD systems. OE


***Benn Voll** is VP Completions, Tendeka. He is an MBA graduate with over 26 years' experience in the oil and gas industry. He has 16 patents in the design and engineering of sand control products. Benn's vast range of knowledge includes marketing, business planning, project management, well completions, hydraulics and drilling engineering.*

***Ismarullizam Mohd Ismail** is Product Line Manager, Sand Control, Tendeka. Mohd is responsible for sand control and inflow control product development, material selection and subsurface modeling. He holds a PhD and MSc. in Mechanical Engineering from University of Leeds, UK, specializing in Oilfield Sand Erosion and Corrosion.*

***Iko Oguche** is a Development Engineer, Tendeka. He is an Advanced Mechanical Engineering graduate (MSc) from Brunel University, London. He joined Tendeka as a development engineer in November 2011 and has been influential in the design and optimization of near well-bore modeling software tools and analysis of well-bore components for monitoring optimum oil and gas production.*

# The harsh reality for materials

Photo by Robert Callaway

**Wood Group Kenny's Luis F. Garfias outlines the challenges relating to material selection and testing for eventual use in harsh environments.**

The increasingly extreme environments faced in oil and gas production are posing more demand on the materials that comprise the vital infrastructure for hydrocarbon extraction and processing. Pushing into frontier fields and deeper reservoirs, while leveraging new technologies and processes to maximize recovery, results in the need for smarter thinking around materials selection, testing, and qualification.

High pressure and high temperature (HPHT) places high strain on materials, and the increasing parameters are evident in the recent reclassification of HPHT to 10,000 psi (689.5 bar) and 350°F (176.6°C). There is a strong safety, and efficiency, case for ensuring correct material selection, accurate testing replicating the environment, and upfront modeling before a material or component can be declared fit for service.

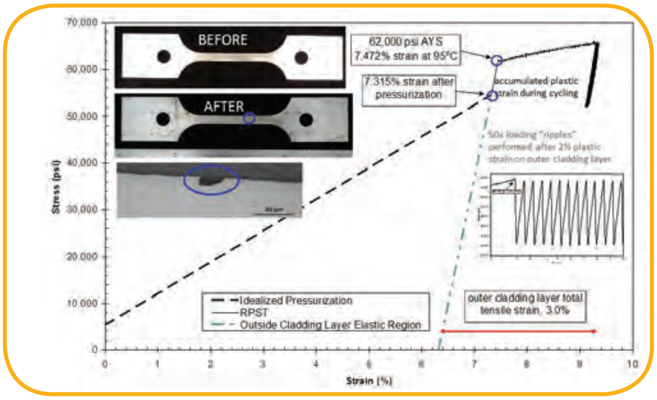



**Fig. 1. Shows the stress-strain curve, pressurization and loading with 50 cycles during RSRT of cladded UNS N06625.**
Image from NACE Paper #10323.

The main goal of integrity management (IM) is to manage the long term integrity of equipment, ensuring that assets perform their required function effectively and efficiently, while safeguarding people, the environment and minimizing capital cost expenditure. Life extension depends on effective IM to reach an extended service life, but IM and materials engineering should be done during the design phase. It should consider the environmental interaction of the materials during the qualification of the new technologies to ensure strategic inclusion of the relevant monitoring systems for corrosion, flow, temperature, etc., to minimize asset degradation over time and to ensure their performance for 20+ years.

## Internal corrosion in harsh environments

The most important variables for harsh environments (from the point of view of internal corrosion) include HP, HT, $CO_2$, $H_2S$, the presence of chlorides and other

chemicals. The combination of these variables with crude or gas typically results in a harsh environment where materials selection is critical and where corrosion monitoring, from wells to production and processing facilities, may also be required.

Top of the line corrosion (TOLC) is an example of a harsh environment that arises with the transport of hydrocarbons with water (and gas) resulting in water condensation in the upper part of the pipeline, where the corrosion inhibitors contained in the fluid cannot inhibit corrosion in the gas phase. Corrosion modeling can assess the most susceptible areas along the pipeline and assist to select the use of corrosion resistant alloys (CRAs) or other engineering strategies to mitigate TOLC.

Another prevention method used during operation is corrosion monitoring. Typically, this would involve coupons or online monitoring systems, although more innovative methods are currently being developed as alternative monitoring. For example, a good flow assurance program can predict extreme environmental conditions that can impact the corrosion processes taking place while the hydrocarbon is being transported. There is a strong incentive to use more than one methodology for corrosion monitoring.

Typically, corrosion monitoring doesn't shed light on the corrosion mechanisms taking place within the harsh environment; that is where corrosion coupons, modeling and flow studies can be an ally and complement one another to provide meaningful corrosion information. A good integrity management plan can lead to cost savings by ensuring the selection of the right materials and technology, and use of the correct tools for corrosion monitoring during the lifetime of the asset.

## Testing and qualification for harsh environments

Mechanical and corrosion testing can be done using conventional techniques and international standards. However, the typical qualification of materials for their use in extreme and/or harsh environments is usually done under ideal conditions, generally those stated in the international standards. Few qualification programs take into consideration the real environment in which the materials will be operating and typically have a poor understanding of the acceleration factors for their basis of qualification.

For example, using constant load

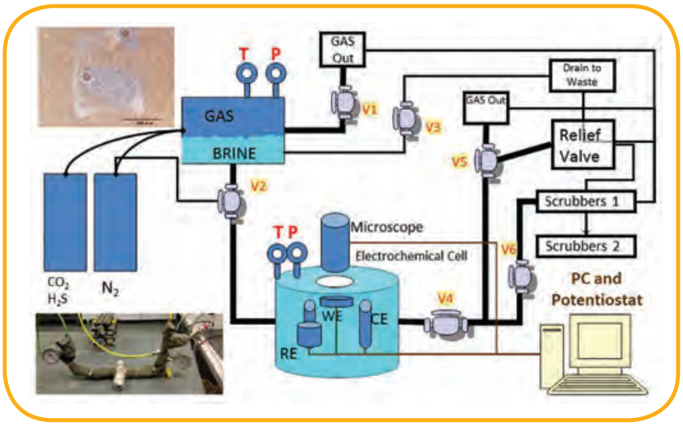



**Fig. 2. In-situ microscopy and electrochemical testing at HPHT in sour environments.** Image from NACE Paper C2012-0001514.

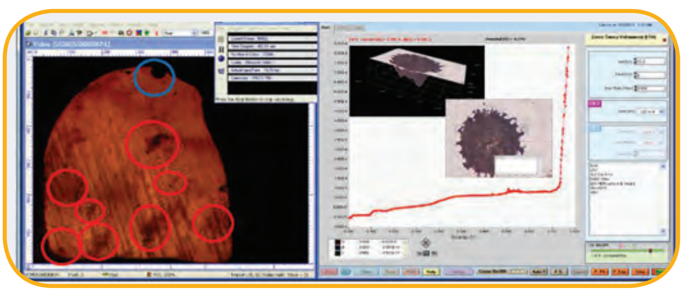


**Fig. 3. Microscopy and electrochemistry at 180°C (356°F) in 20,000 ppm chloride (40 bar $CO_2$, 0.025 bar $H_2S$ and 0.02 M $CH_3COOH$) of a duplex stainless steel.** Image from NACE Paper C2012-0001526.

testing (which is simple and widely understood) generally oversimplifies the problem and cannot address corrosion fatigue under the real cycling conditions. Similarly, other tests such as slow strain rate testing (SSRT), which is aggressive and rapid, can be too aggressive and it can be difficult to determine if cracking occurred inside service conditions. On the other hand, ripple strain rate testing (RSRT) includes corrosion fatigue and is adaptable, but with the drawback of being more complex and costly than constant load testing and SSRT. Still, all of those methodologies need to take into consideration the real environment and should mimic actual conditions in order to be acceptable as qualification methods.

## In-situ testing to simulate internal corrosion in harsh environments

Corrosion testing in harsh environments, which typically contain $H_2S$, $CO_2$ and NaCI in a liquid/gas mixture, is typically conducted in autoclaves at HPHT, involving several samples that will be immersed in the liquid/gas mixture under HPHT. The tests can last from days to months and in some cases the samples are totally disintegrated at the end of the tests. Therefore, no assessment of the expected lifetime of the metal can be done using weight loss and no assessment of the type of corrosion mechanism can be done on the coupons.

Ideally, the metals should be observed during the test to identify the onset of corrosion (for example general corrosion or localized corrosion) while the sample is immersed in the HPHT harsh environment. This can be done through a new methodology using a mini-autoclave that allows concurrent and in-situ microscopy and electrochemical tests in real time.

In Figure 3, the sample was heated to 180°C (356°F) in 20,000 ppm chloride (40 bar $CO_2$, 0.025 bar $H_2S$ and 0.02 M $CH_3COOH$). Pitting corrosion was confirmed both visually and in the electrochemical signature.

The advantage of using this technique is that it provides real-time visual confirmation of the processes (corrosion, degradation, microbial attack, etc.) that happens in the material inside the autoclave while the sample is immersed in the HPHT harsh environment. Another advantage is that the material can be monitored over time and video recording can be used to compare their interaction with the environment. However, this technique can only be used below 4000psi and 400°C (which is a limitation given by the materials of construction of the window).

## Challenges

Many testing programs exceed 150°C (302°F), but range from 3000psi (206.8 bar) to 15,000psi (1034 bar). New industry standards for HPHT are being developed. For example, the current API 14A, Edition 11 standard for surface-controlled subsurface safety valves (SCSSVs) requires that SCSSVs with a working pressure >10,000psi (689.5 bar) be tested to 5000psi (344.7 bar) above working pressure, rather than the 1.5 times working pressure requirement of

API 14A, Edition 10. A design guideline for HPHT is currently being developed (API 17TR8) by many experts from the oil and gas industry. These new design guidelines will serve as a starting point for testing and qualification at HPHT in harsh environments.

Standard testing is the common approach in the majority of cases, but the correct approach will be to model the environment and mimic the actual conditions expected in the field. This applies to corrosion testing, mechanical testing (fatigue, fracture, hydrogen, cyclic loading, etc.), and dynamic testing in harsh environments. All modeling and testing needs to take into account the actual environment, the stresses, and simulate the expected lifetime, as well as ensuring that the acceleration factors for the qualification testing are in good agreement with the environments and lifetimes expected for the asset.

Measurements for reservoir conditions can often be made in error; not due to the measurements being performed improperly, but that concentrations, pressures and temperatures are measured at different locations and at lower temperatures. This causes problems as the amount of dissolved acid gases is highly dependent on temperature and pressure specific to each condition.

Well fluid compatibility (sour vs. sweet service) is another key issue, as are temperature de-rating effects on minimum yield strength. A finite understanding of material properties is essential.

Regarding non-metallic materials, the industry is currently developing polymers and seals that can withstand these ultra-HPHT well conditions up to 30,000 psi (2068.5 bar) and 260°C (500°F) while retaining mechanical properties, chemical performance, and well fluid compatibility. Reliability prediction, environmental concerns and safety issues must be addressed, and further seal research needs to be conducted. In some cases, metal-to-metal seals may replace elastomers.

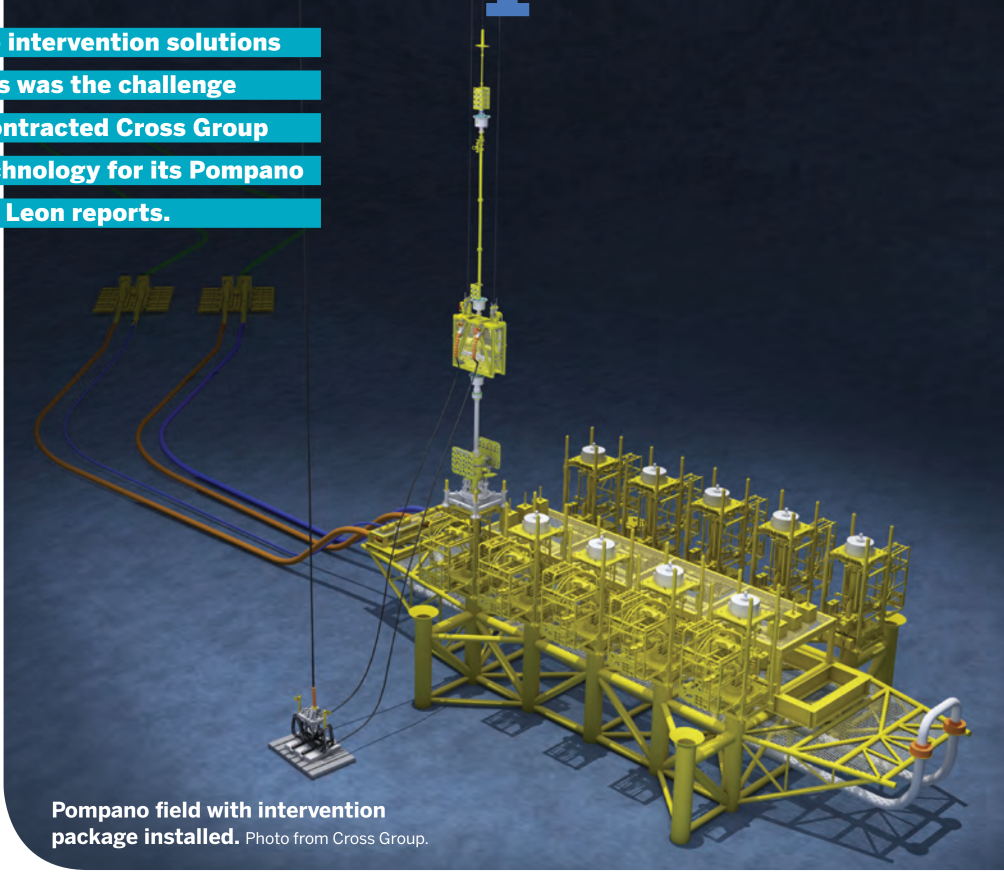
The crux of the challenges relating to materials in harsh environments is the need for accurate testing and qualification in the context of the actual operating environment, correct material selection for each application, and the use of modeling in the early project stages.

There are a number of variables which must be considered when designing a device, planning to build a system or simply selecting a material for extreme and/or harsh environments. Different considerations must be taken for subsea, topside, or onshore oil and gas production; the nature of the HPHT reservoir will highly influence the materials selection. Having the correct materials in place for the purpose and using the optimum monitoring systems are essential to avoid failures. **OE**

***Luis F. Garfias*** *is a materials and testing consultant at Wood Group Kenny in Houston, focusing on projects related to materials, asset integrity management and testing at HPHT using electrochemistry and microscopy. He is an active member of NACE International and The Electrochemical Society. Garfias holds a B.Sc. in chemical engineering from Universidad Autonoma de Yucatan (Mexico), a M.Sc. in corrosion science and engineering from University of Manchester Institute of Science and Technology (UMIST - UK) and a Ph.D. in materials science from Oxford University (UK).*

# Intervening on Pompano

**Unique fields deserve equally unique intervention solutions when production begins to wane, this was the challenge Stone Energy had to meet when it contracted Cross Group to develop new methodology and technology for its Pompano subsea production template. Audrey Leon reports.**



**Pompano field with intervention package installed.** Photo from Cross Group.

When Lafayette, Louisiana-based Stone Energy purchased the Pompano field from BP in late 2011, the field's subsea intervention kit was in need of serious refurbishment while several subsea wells on Pompano Phase II, a 10-well subsea template remained shut-in.

In 2012, Stone Energy had 16 platform wells producing, and only three of 10 template wells producing. An intervention would be necessary, but the subsea system, the only one of its kind in the US Gulf of Mexico, had issues such as stuck tooling that made through-flowline (TFL) intervention unworkable, said Craig Castille, director of Deepwater Drilling and Completion at Stone Energy.

Before BP sold the field to Stone Energy, it mulled a total refurbishment of the original intervention kit, which is now-20 years old. Now that it was Stone's challenge, Castille says the company estimated a total refurbishment of the original intervention kit could cost as much as $40-50 million and the operation and maintenance of the complex system would increase safety risks and cost. Castille says that the company knew there had to be a better way.

"Not having a system in place wasn't an option," Castille says. "We had no way to do plugging and abandonment work on these wells. It wasn't an 'if,' it was how soon can we get it done?"

## The field

Pompano was one of the first deepwater projects in the Gulf of Mexico and it remains a production hub for neighboring fields, including the ExxonMobil-operated Mica field (Stone Energy 50%), which is tied back to the Pompano platform through two, 8in flowlines.

The Pompano field was discovered in 1985 by BP and Kerr-McGee (acquired by Anadarko in 2006), with first oil in 1994.

The 8mi-long Pompano field sits inside six lease blocks including Viosca Knoll Block 989 and Mississippi Canyon Block 28, about 120mi southeast of New Orleans, in 1100-2200ft water depths.

BP installed a 40-slot fixed platform in 1994, in the southeast corner of the Viosca Knoll block, in 1290ft water depth. Pompano's 10-well diverless subsea oil production template system was installed in 1995 in Mississippi Canyon, about 4.5mi southeast of the platform, at 1865ft water depth (Clarke and Cordner)[1], with first oil in 1996.

The field's Pliocene reserves and some of the offset Miocene reserves could be drilled from the platform with the use of extended reach drilling. The rest of Pompano's Miocene reserves were developed using the subsea well template[2] (Cordner and Klienhans).

## Through-flowline systems

In a 1999 SPE paper by then-BP Exploration engineers James P. Cordner and John W. Kleinhans, a TFL system, deployed from a moored mobile offshore drilling unit (MODU), was selected for the field's subsea template after numerous concepts were evaluated[2].

"Based on the results, the best match-up of reservoir needs, including uncertainty about both well count and reservoir management needs, indicated that subsea facilities comprised of a 10-well, subsea template structure and designed for production wells outfitted for TFL servicing would best meet objectives," they wrote.

TFL was cutting edge technology when developed almost 30-40 years ago as an alternate solution to high cost, high mobilization drilling vessel intervention back into a subsea well. TFL was seen as the economic solution to Pompano's unique and troublesome reservoir properties that might be plagued by several planned (and unplanned) interventions, says Brian Skeels, emerging technology director at FMC Technologies and an adjunct professor of subsea engineering at the University of Houston.

While Pompano is currently the only field using a TFL system in the Gulf of Mexico, it's not the only one in the world.

"What started with Exxon's SPS project at Garden Banks 70/71 back in the 1970's later moved to Shell/Esso's Central Cormorant project in the UK's North Sea sector in the 1980s, and Statoil's (Saga Petroleum) Snorre project offshore Norway in 1992. TFL was also experimented with on other North Sea pilot projects for Mobil and Conoco in the same era," Skeels says.

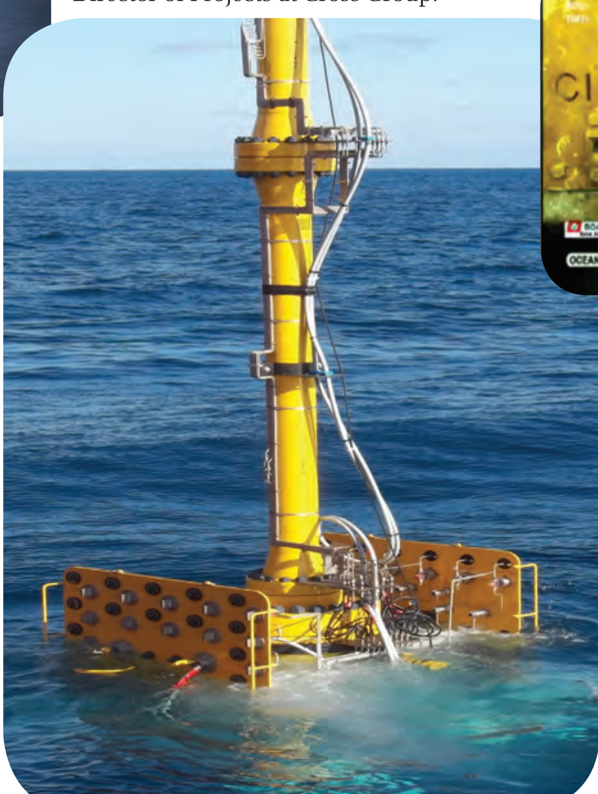
Skeels, who serves on an API Subcommittee 17 executive committee, says that TFL continues to have its merits. "But, its cachet may have come and gone," he says, when compared to some of today's lower cost intervention solutions like monohull riserless intervention.

The way the TFL system works is that tools have to be pumped through a 4.5mi flowline from the Pompano platform and into a well in order to perform work that is typically done with slickline on conventional dry tree wells. This requires the TFL tools to be extremely flexible, almost like snakes, says Jason Leath, Director of Projects at Cross Group.

"You have to pump them in and they go through a service loop in the tree and they go downhole. You have two production bores. You have to pump down one and reverse out, basically pumping your tool all the way back to the platform when it is done," he says.

The key to TFL technology, Skeels says, is understanding how it works and then building and installing the equipment correctly with that "pump down and pump back" understanding in mind. "If the pipeline is improperly constructed (welding slag or misalignment of joints) or the trees do not feature the right chamfers and entry/exit angles, or later on you developed a production problem, the pipe was clogged with paraffins, or you had debris issues like sand or corrosion, you could really get yourself in a bind by sticking a TFL tool somewhere in the maze of piping," Skeels says.

Stuart Morrison, a senior subsea engineer at Stone Energy who oversaw the completion workover riser (CWOR) design and refurbishment for the operator, says another problem is few people in the industry with this in-depth knowledge of TFL systems remain. Additionally, there's only one company that provides the pump-down equipment for TFL systems, Otis (now Halliburton).



Deployment of the lower completion package. Photo from Cross Group.


**Left: Tree ROV panel. Right: The insert safety valve ROV bucket.** Photo from Stone Energy.

This meant Stone Energy had to find a way to intervene on its subsea template with an open mind, Morrison says, bringing in several intervention companies to offer solutions before eventually settling on Cross Group.

"We knew we had work to do, relative to the template," Castille says. "The system was in ill-repair and needed to be refurbished. Because of the cost of rigs today, putting a rig on location for a very minor intervention was not cost effective."

Stone Energy needed a more flexible system in order to carry out interventions on at least two wells that were shut-in, one of which had been out of production for 10 years. Stone laid out its needs, including the freedom to use DP semisubmersible or DP monohull vessel rather than a moored MODU.

## Finding a solution

The Pompano field and its TFL system wasn't a total mystery to Cross Group. Several team members overseeing the project had previously worked on the original equipment for BP while at Saipem, says Larry Klentz, vice president, Operations, Cross Group.

Cross Group's proposal provided a new system, which would grant access to each wellbore and annulus through a new triple bore selector and valve assembly, allowing the work to be done with or without a riser. Working with Houston engineering firm OilPatch Technologies (OPT), the two companies created and manufactured this new system that would interface with both Cross Group's upper intervention package and the existing triple bore vertical tree/TFL system.

OPT lead the design, analysis, drawings, manufacturing, and assisted with testing of the new system. The work took approximately 18 months, says Gary Galle, associate principal and director of new markets and new technology, OPT.

The biggest challenge, says Galle, was figuring out the requirements. Cameron made the original equipment and work on the new system meant working with Cameron, Cross Group, Stone Energy, and others to define and close interfaces.

Galle says by keeping the adaptor's design as modular as possible, it allowed OPT to evolve with changing needs and requirements. "We broke it up into enough sub-components so that if we changed one, it wouldn't change the overall design," he says.

## The technology

Cross Group considered several concepts

An aerial shot of the *BOA Deep C.*
Photo from Cross Group.

**Production rates comparison of the first two wells to be brought back into service following intervention work**

| Oil production rates | Well name: TB-02 | Well name: TB-03 |
|---|---|---|
| Prior to offline | 825 bo/d (offline, Q2 2004) | 325 bo/d (offline, Q4 2013) |
| After intervention | 1350 bo/d IP (Flush Production) | 1175 bo/d IP (Flush Production) |
| Current (as of March 2015) | 900 bo/d IP | 670 bo/d IP |
| Current gross production on platform from the Pompano wells, Pompano template wells, and Cardona wells is approximately 14,500 bo/d and 20 MMcf/d of gas. | | |

before landing on the one selected, but this design in particular was, in-part, inspired by Klentz and his team's previous experience on Pompano.

"We call it (the triple bore selector) a dynamic funnel," says Klentz, who spent 14 years at Saipem before Cross Group. "It's a hydraulic actuator that shifts from whichever of the three bores that is selected, and that allows you to select whatever bore in which you need to work. Under that adaptor is a valve block that gives you the ability isolate the other bores, as well as pump in ports, full circulation capabilities, giving you full access to your toolstrings."

Klentz says while he and Leath were at Saipem, a 4x2 dual bore type package with a slickline run kickover tool was used on other projects. This allowed access to the annulus bore through a mono bore riser. "Building off that concept, originally, we thought we could do a hydraulic kickover, but this (adaptor) worked out to be the best, most efficient, fewer moving parts, if it breaks you can fix it easily."

For the Pompano intervention, Cross Group paired the adaptor with its existing 3.0 riserless intervention system in conjunction with some select equipment from the original CWOR and the new dynamic funnel assembly to fulfill the scope.

Cross Group said that one of the hurdles for the project was the requirement to run e-line tractor tool strings – an ability the original CWOR did not possess. The minimum requirement was a system rated for 1865ft water depth and a bore pressure of 5000psi.

"Through our package, it allows work to be done from a monohull vessel, which is a much smaller vessel, with a much smaller day rate," Klentz says. "The equipment spread is a quarter of what it would normally be, meaning lots of cost savings. It's safer because they don't have to set anchors, and can do it from a DP vessel.

"The package actually gives them greater capabilities because you can run larger vertical toolstrings through it than the original intervention package designed for this work," Klentz says.

Leath, agrees, saying: "They went from the biggest, bulkiest, most expensive way to do it 20 years ago to one of the smallest, most mobile methods of doing it today. I don't believe that type of thing has ever been done before."

## Crossing the finish line

Cross Group, was also requested by Stone to help prepare the RFP (request for proposal), which provided the technical requirements to find and contract an appropriate vessel. Based upon the vessel assessment for the intervention project, Cross Group chose the up to 2000m deep water offshore construction vessel *BOA Deep C* for the job. The *BOA Deep C* comes equipped with two ROVs, a 250-ton active heave compensated crane, and 1150sq m deck space. Cross Group staged its equipment on the vessel's back deck.

The vessel arrived at the Port of Galveston in mid-November, and the crew set sail for the Louisiana coast shortly after Thanksgiving. The job was completed by mid-January with all parties proclaiming it to be a huge success (see table for production figures), despite a few hiccups due to the currents, and weather limitations, says Kevin Smith, a completion engineer with Stone Energy who prepared the intervention work plans on the two wells to be serviced. Smith says the crew rigged up a work tower to minimize the wind limitation on the crane.

All parties involved in the intervention attribute its success to open lines of communication.

Jimmy Reed, senior deepwater drilling superintendent for Stone Energy, who was responsible for the overall execution of the work said that the biggest challenge for any project is getting everyone on the same page, and the companies (Stone Energy and Cross Group) were able to have daily conference calls and discuss not just the operations but HSE support with all parties involved.

"There was outstanding communication, HSE achievement, and to top all that off, we got the job done. All the new equipment functioned well," Reed says.

"There were no issues safety wise, even with cramped quarters on which the personnel had to work; load on back of the vessel and perform the operations without getting injured, and no near misses," he says.

## The future

Castille says the intervention completed in January is just the beginning of the revitalization of the subsea template, saying Stone Energy has invested $30 million in new tree technology for two wells, which could be a future workover or sidetrack. In addition, the company continues to add to Pompano. It recently tied in two Cardona wells and will develop the Amethyst discovery as one well subsea tieback.

"Pompano is producing 14-15,000 b/d," Castille says. "When we got it from BP production was at 4000 b/d." OE

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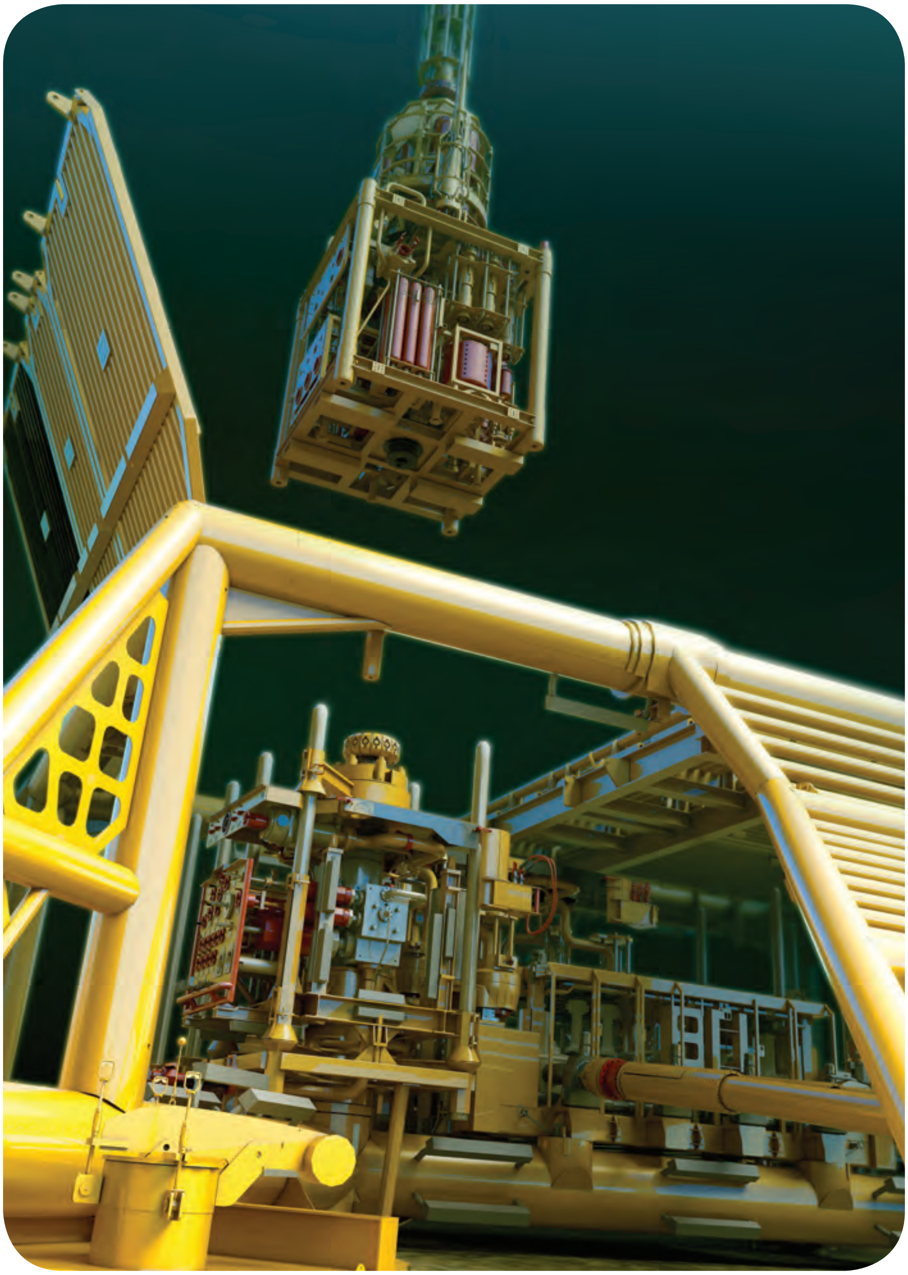
# RWLI makes its mark

**Ask about subsea well intervention and most assume it's riserless light well intervention you want to talk about – for good reason. Elaine Maslin reports.**

Riserless light well intervention is a growing area, seen as able to reduce well intervention costs, by bypassing the need to use a drilling rig, and increasing the number of well interventions that can be performed. While once a method operators were nervous to use, it's now well-established in the North Sea and gaining acceptance in the Gulf of Mexico.

Contractors and service providers are joining forces, eying new areas to introduce their technologies and operators are pushing the boundaries of RLWI into deeper waters.



Subsea light well intervention visualized by FMC Technologies.

### Why riserless?

Riserless light well interventions are performed to address well integrity issues and maintain or enhance well production without using a riser, by deploying intervention tools into the well on wireline, electric-line and slickline using a subsea intervention lubricator. A range of activities can be performed, from acquiring production data and running integrity logs to retrofitting gas lift valves and performing scale squeezes. Riserless stimulation, or high-rate pumping for fracturing, is also being used to improve production.

"Over a period of time, reservoir conditions change, such as producing more water or you might want to set plugs to re-perforate," says John Thomson, intervention engineer, Global Wells Organization, BP, based in Aberdeen.

Henning Berg

For subsea wells, the need for interventions is greater and will become more so as wells become more significant-sized producers in deeper water. Subsea wells, which, due to fewer planned interventions typically have a much lower recovery factor than dry tree wells, actually require even more attention, says Henning Berg, President, Subsea Services, OneSubsea.

Bjarne Neumann

Using RLWI, operators can reduce vessel costs and perform more interventions. You can operate on 20-30 wells a year using RLWI, says Bjarne Neumann, director of well intervention services at FMC Technologies, compared to 10-15 per year using riser-based operations.

Furthermore, money spent on intervention brings greater return than cash spent on greenfield projects, says Carl Roemmele, Well Access Lead at GE Oil & Gas. "This is why we are seeing the big drive into monohull deployment," he says. "Monohulls are a quarter to a third of the cost of a drill rig, depending on what you get on it and the water depth. If you can go behind a rig to tidy up wells, do testing or pick up intervention, you can save rig days and money. Most reports you read predict double-digit compound annual growth rate in the intervention space over the next 3-5 years."

### Dominating the market

To date, Norway and the UK North Sea have been a front runner in RLWI, due to the fact it has the most mature subsea trees in the world, Neumann says, with dedicated riserless light well intervention vessels established in both basins. "Operators are now so familiar with RLWI they even have a vision all intervention will be done riserless in the future. That is their target because it is more cost effective. It is a technology proven over the years to be reliable, safer and more efficient," he says.

BP has had a dedicated well intervention campaign west of Shetland on the UK Continental Shelf, under a long term alliance led by Island Offshore (with Oceaneering, FMC Technologies and Altus Intervention) using the *Island Constructor*, since 2009, as well as operations on its other North Sea assets with Helix Energy Solutions, using the *Seawell, Well Enhancer* and *Skandi Constructor*. The firm has 197 subsea wells on the UKCS, the deepest in about 500m water depth, west of Shetland, where the weather window spans just April to mid-September.

John Thomson, intervention engineer, Global Wells Organization, BP, based in Aberdeen, says the long-term contracts have meant continuous improvements have been made, both around managing the challenging weather conditions west of Shetland [*OE*: January 2015] and operationally. In 2007, BP performed one subsea well intervention operation in the North Sea a year. It is now about 12, in that short season, says Thomson, and they're delivered on time and on budget. "The North Sea is not a challenge any more [for RWLI], it is becoming routine" he says.

Colin Buchan, Wells Engineering Manager Subsea Well Intervention at Shell, says Shell first used RWLI in the North Sea in 1994. Since then the technology has been used more and more in the North Sea and now in the deepwater basins in the US Gulf of Mexico, Brazil and West Africa. However, to be fully adopted in deepwater, technology, vessel capabilities and economic viability need to be addressed.

### Deepwater opportunities

"Shell has a long history of using RWLI techniques," says Buchan, co-chair of this year's Deepwater Intervention Forum conference, organized by ***OE*** and held in Galveston. "In up to about 1000ft water depth, it is established technology. Beyond 1000ft, there are some technology concerns within the operator community as to reliability and environmental protection."

Some of the concerns are around the ability to isolate the well from the surrounding environment on the seabed. "It is a dynamic seal which you are running a conduit wireline or slickline through and that has to isolate the well fluids from the environment," Buchan says.

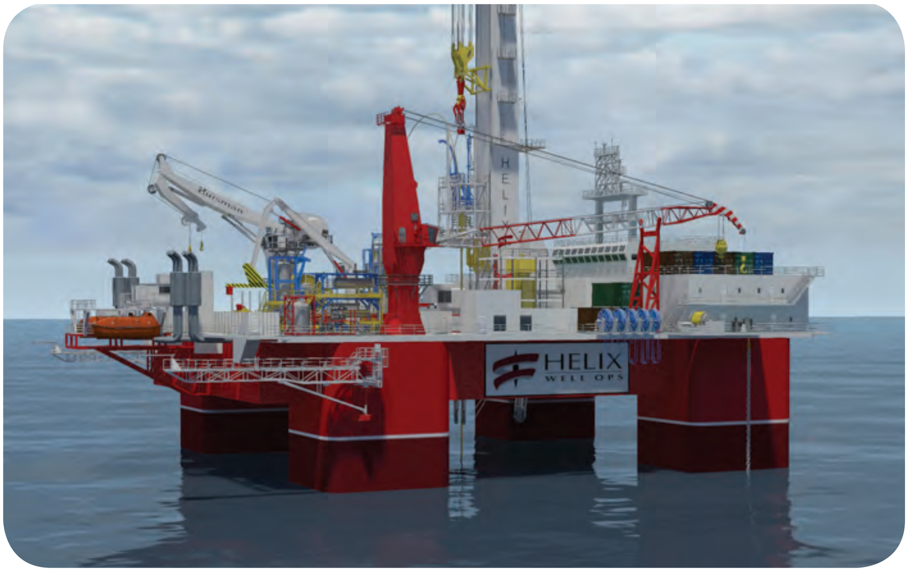
Using a riser-based intervention system, the seal is on the rig floor. On the seabed, the seal has to be able to deal with the hydrostatic pressure. The scenario when the hydrostatic pressure is greater than the well pressure creates additional demands on the sealing mechanism, which means proving a reliable pressure control system is crucial.

It's an area Shell is working on closely, alongside technology vendors. Shell is keen to have the technology ready to work on its subsea well stock, which includes deepwater wells offshore Nigeria, Brazil and in the Gulf of Mexico. So far it has performed subsea well intervention operations on wells at 3800ft off Nigeria and to 6200ft off Brazil. The current industry record is 8100ft, Buchan says.

"We are going through a learning curve as an industry on how to maintain an effective seal in these water depths. It is coming, slowly," Buchan says.

Offshore Nigeria, Shell developed a system which could be mobilized on a vessel of opportunity. Instead of using a conventional rig, with an integrated subsea lubricator system, the firm used a lower riser package, emergency disconnect package and a pressure control head – effectively a workover riser system

**An emergency disconnect package and lower riser package.** Image from OneSubsea.




**Helix Energy Solutions' *Q7000* semisubmersible well intervention vessel.**
Image from Helix Energy Solutions.

**Helix Energy Solutions' operates the *Skandi Constructor*.** Image from Helix Energy Solutions.

adapted to be a subsea lubricator system. The same system, owned by Shell, can also be used from a conventional rig and was recently used in this way, this time with a riser, due to the need to used coiled tubing.

It is a market that is expected to grow. "Deepwater is an area a lot of people speak about as a potential area for growth and I believe that's the case as well," Buchan says. "There will be more opportunities as we meet the technology challenges and demonstrate the capability. But this needs to be built on firm foundations and we need to make sure as an industry we are doing it correctly and doing it right, the first time, every time.

## Coiled tubing

There is also an aim to be able to provide riserless coiled tubing interventions. Although sand removal can be performed using riserless systems, some wells, may require sand removal using coiled tubing and coiled tubing is currently unable to be run through riserless systems.

BP has this issue in some UK North Sea wells, for which it is looking for a solution. "We would like to use riserless coiled tubing but, while it has been talked about for a good few years, the capability has not been developed yet," Thomson says.

Island Offshore, working with Baker Hughes, last year used open water coil tubing drilling from the *Island Performer* on the Rogfast road tunnel connection project outside Stavanger. The pair drilled in the Boknafjord using coiled tubing without a riser from the monohull *Island Performer* to collect rock samples from the seabed for the civils contractor.

But, it is still early days for riserless coiled tubing, many believe. "A number of service providers are looking into doing open water coiled tubing in a safe manner," Neumann says. But, it might not be that easy, he says, because established codes would be challenged is when the tubing effectively becomes the riser. "I don't see open water riserless coiled tubing being operated in the next two years," he says.

## Global growth opportunities

Even without expanding the RWLI envelope, operators, vendors and service providers see a growing RWLI market.

Regions outside the Gulf of Mexico and North Sea are showing increasing interest in RWLI, but their take up could be hindered by the availability of equipment and/or the operators have yet to use the technology and are a bit reluctant to be the first in their region, Neumann says.

"The industry has developed a wide variety of downhole tools and has increased the range and scope of what can be accomplished using riserless systems. The challenge is to ensure that operators are fully aware of these recently developed capabilities. There are also the wells which have sand ingress, which require coiled tubing operations.

There's also a "chicken and egg" scenario. Service operators will be unwilling to move their vessels into regions, such as West Africa or Brazil, if there's not enough work there for them. Island Offshore, for example, has capability to go to 1500m, but it would need a campaign to make it viable to move a vessel to say West Africa. In such circumstances, operators need to work together to spread

**Scotty Sparks**

the cost of a vessel, Thomson says.

However, "As a standalone business, well intervention is at an early stage," says Scotty Sparks, Vice President, Commercial/Strategy, Helix Energy Solutions. "Riserless intervention is quite well-established in the North Sea, and both riserless and riser-based intervention from a dedicated vessel is common in the Gulf of Mexico, but in other regions, well intervention is still predominantly performed from a rig at a much greater cost. If you consider the subsea tree count, however, Brazil and Africa are the high points and we see a strong business case for both riserless and riser-based operations in those areas."

## Integrated service offerings

Service companies have been working hard to offer attractive packages. FTO Services, an RLWI partnership between FMC Technologies and ship owner/operator Edison Chouest Offshore, recently relocated the upgraded RLWI vessel *Island Performer*, operated by Island Offshore to the Gulf of Mexico. [See more on the *Island Performer* on page 26.]

Last year, Helix Energy Solutions, OneSubsea, and Schlumberger formed an alliance to focus on subsea well intervention, leveraging Helix's growing dedicated intervention vessel fleet with OneSubsea's equipment and technologies and Schlumberger's downhole expertise. The alliance was officially signed on 6 January 2015.

"Our thinking was to create a full package and to cover the full value chain. You need the vessel, the access package and the in well services. Having the full package minimizes the interfaces and number of contract points with the client, as well as creating possibilities to optimize the crew size and the equipment," says Henning Berg, OneSubsea. "Helix is the leader in intervention vessels, OneSubsea has been making intervention packages for the last 20 years and Schlumberger is the best in class for in-well services."

Helix currently has five well intervention vessels, from small intervention vessels up to a heavy duty semisubmersible, and it is expanding its fleet. This year it will take delivery of the *Q5000* semisubmersible, next year two large monohull units will be delivered to work for Petrobras, and in 2017, the *Q7000* semisubmersible will be delivered. Intervention packages are due to be replaced on some of the older vessels, Sparks says.

The alliance sees growth opportunities, in Brazil, Africa and Asia Pacific, where it can draw on the established bases of its component companies, Sparks says.

FMC's Neumann sees similar opportunities to make efficiencies, with integrated and earlier contractor engagement. "At the moment you build a vessel, build a stack, and then some time down the road the vessel and stack owners and others meet, often too late to make changes," he says. "To be partners in the planning process would enable us to collaborate to ensure that the vessel is designed with RLWI in mind so that it can be operated more efficiently."

"We can reduce the amount of maintenance, reduce the number of power lines, and I believe one day we will see the industry move forward various packages being deployed from one vessel, for activities such as maintenance. So you have one maintenance team, and not three, and this will bring the economics down," Sparks says.


**FTO Services' *Island Performer*.** Photo from Tor Aas-Haug/Mediafoto.

GE Oil & Gas is also beginning to flex its muscle in this area. The business recently reorganized four related business units, including new build work over, intervention and completion equipment, offshore operations, a new productions introduction team (research and development) and the Wellstream subsea construction group into a single entity – Well Access.

Roemmele says GE Oil & Gas wants to offer something different, leveraging its business streams, products (the "GE Store") and capabilities as well as through forming strategic partnerships, often on a project to project basis to address particular issues for clients. An example of technology GE is developing which could then be used in the well intervention space is the 20,000 psi blow out preventer project it is involved in. "We have the technology in the valves space that we could put to use from an intervention technology point of view," he says. GE Oil & Gas is also working to make components lighter, to reduce weight and footprint, he says. Sensing and prognostic capabilities used in other sectors, such as aerospace, will also come into the picture he says, to enable better intervention planning, which could be particularly useful for more remote installations.

## The opportunities

The opportunities seem abundant, the technologies ready and continuously being extended and the contractors and service providers primed to meet operator's needs. "We have an increasing number of subsea trees around the world and in order to maintain production, operators need to do more intervention," Neumann says. OE

# Inflatable support

**Chris Sparrow shows how using inflatable buoyancy for pipelaying operations could result in shallow-water savings.**

**Inflatable buoyancy units during deployment on Wheatstone.** Photo from Allseas.

The "time is money" equation may well be the most overused business cliché, but it is still as true and as relevant to pipeline installation in 2015 as it ever has been.

For pipeline installation contractors, the primary consideration is to get the job done and to be offsite and onto the next project as safely, as efficiently and as quickly as possible.

Buoyancy used on such operations is very often viewed as a necessary evil, and maybe not given as much consideration as it could be, as the knock-on effects of using an inefficient buoyancy solution are often hidden – although they can have a major impact on the overall costs of a project.

Contractors have the ability to fabricate their own steel buoyancy tanks and may, therefore, look no further than that when looking to float or pull a pipeline into position. However, the potential savings to be made using buoyancy solutions, which create greater efficiencies as well as a reduction in the risk profile can be enormous.

## The past

Historically, contractors needing buoyancy for a pipelaying operations would probably have welded up some old oil drums and then abandoned them at the end of the project. More recently, in-house fabricated, enclosed steel cylinders became the norm. The drawbacks to using steel include:

- It is heavy, large, hard to transport, handle and deploy, requiring specialized lifting equipment.
- It needs to be outsize to support its own weight, before offering extra buoyancy to lift loads—a particular drawback in shallow-water works where every foot of un-necessary profile requires an extra foot of trenching
- Units become a projectile, when released from the submerged pipeline at the end of the process.
- Units deteriorate between projects resulting in ongoing maintenance requirements.

**IBUs on Tie-in panoramic.** Photo from Allseas.

While steel is still being used by some, the market is moving towards safer and more efficient technologies.

## The plastic revolution

Over the past 25 years, a number of manufacturers have emerged offering two types of plastic buoyancy for installation projects: solid (i.e. foam-filled) and inflatable.

Solid plastic buoyancy is now in widespread use. It is typically formulated from syntactic foams for deepwater applications, but it is also sometimes seen in use at, or near, the surface on pipeline installations. While there may be some relatively minor variation at depth and over time in the total amount of buoyancy that such units can offer, they will generally provide near-constant amounts of buoyancy throughout their service lives. This is perfect in scenarios such as riser buoyancy, where a constant amount of uplift is required at depth.

However, solid buoyancy has disadvantages in shallow water applications. Although lighter than steel units, solid plastic units are heavier than inflatable units and, as with steel units, they will also require special lifting equipment to deploy. Also, as with steel, the extra weight will result in a bigger unit with a bigger profile to produce the same amount of uplift as a much smaller inflatable unit.

If, as a contractor, you are looking to remove 85% of the weight of a 28in pipeline to bottom pull it through <1.5m of water, it is likely that solid plastic units will sit too high in the water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**Allseas' Tog Mor flat-bottom, anchored barge used for pipelaying on Wheatstone.**
Photo from Allseas.

**Crocodile infested waters in Angola.** Photo from Unique Seaflex.

to provide the buoyancy required, given that only the proportion of the buoyancy unit which is underwater is generating uplift.

The proportion of the solid buoyancy unit above the surface will also add weight to the pipeline, increasing friction. And the larger the solid plastic units the greater the volume of expensive specialist foam required to fill them – whereas the larger the inflatable buoyancy unit the greater the volume of zero-cost air which is required to fill them.

### Why inflatable buoyancy?

Air-filled bags offer a number of technical and commercial advantages:

- Operational flexibility, via remote, user-controlled, variation of total buoyancy from the surface and the ability to control the amount of buoyancy at the moment it is required.
- Surface venting is possible at the end of the process, to increase safety by releasing deflated units under zero load.
- You can, roughly, expect to fit about 40-50-ton of solid steel or plastic buoyancy capacity into a 40ft container, whereas up to 500-ton of inflatable buoyancy capacity can fit into a 20ft container. Some large pipeline pulls currently in bid phase in various parts of the world require up to 2000-ton of buoyancy. Such a project would require two 40ft containers filled with inflatable buoyancy versus up to 50 40ft container loads of solid buoyancy. Same capacity, <5% of the shipping volume – reducing both cost and carbon footprint as well as making for much easier storage on the job.
- Inflatable buoyancy units are easy to handle: mass to buoyancy ratio is about 1%, so a unit offering 5-ton of uplift will typically weigh less than 50kg and can be handled onto the pipeline by two men.
- Competitive per ton capacity to capex compared to steel or solid plastic buoys, and able to be rented on a project-by-project basis.

There are a few different design and construction philosophies amongst the various manufacturers of this type of buoyancy, but for the canopy itself most of the recognized manufacturers will be using a Trevira-type panama-weave base cloth for maximum durability, which is then coated with a marine-resistant PVC. Strops and connectors fitted to such bags should all comply with the 7:1 Factor of Safety as per IMCA D-016 guidelines.

### How air works

Unique Seaflex, a Unique Group company, manufactures inflatable buoyancy which behaves according to the principle of Boyle's Law. This dictates that as the bags are lowered deeper into the water they decrease in capacity, because the air inside gets compressed and occupies less volume (the reverse applies in applications where bags are being used to dynamically lift from seabed to surface – for which parachute-style bags rather than enclosed bags are typically preferred, as the excess air generated during ascent can vent freely from their open undersides).

While this effect can require topping up the inflatable buoys from the surface on their way to touchdown, this is a relatively minor inconvenience given that workboats will normally be patrolling in the vicinity.

In some cases, loss of buoyancy becomes part of the engineering solution. On a project currently in bid phase by Seaflex, 138 x 2-ton bags were recommended to be fitted to a 16in. gas pipeline on a barge positioned in less than 6m of water, in the knowledge that at the touchdown point they would generate less than the calculated 1.5-ton average uplift required to facilitate the pull. As the pipe is to be pulled into shore from that touchdown point, the air inside the near-shore bags will expand to ensure the required 235-ton total uplift along entire 1.9km pull.

### In Practice

Single attachment Mono Buoyancy Units were used by Allseas during July 2014, for the shore approach of a 44in pipeline on Chevron's Wheatstone project. A combination of a change in engineering requirements at short notice as well as the buoyancy modules that had been originally earmarked for this campaign still being used on another phase of the project meant that 250 x 3-ton modules were urgently required for the near-shore installation.

Seaflex's large rental pool is designed to cover exactly this type of urgent requirement from stock, and the lack of shipping volume offered by these inflatable units made for extremely cost-effective airfreight from the UK to Australia compared to up to 20 containers which would have been involved in air-freighting 750-ton of solid floats halfway around the world.

The use of buoyancy loss at depth to engineering advantage was also key to this campaign, as buoyancy was only required by Allseas to provide enough uplift of the pipeline in the top part of the water column without affecting pipeline stability on the seabed in the way that modules offering a constant amount of buoyancy would have done. Seaflex modules have also played a major part on the above water tie-in: 24 x 5-ton multi-attachment inflatable buoyancy modules have been used, allowing for a staged inflation of buoyancy during the recovery process when required.

Where diver intervention to remove the modules from the pipeline after touchdown is not possible, tailored attachment and release mechanisms are required. In 2010, a 2.3km three-pipe bundle (composed of 18, 22 and 24-in. pipelines fitted with 5-ton Seaflex Mono Buoyancy Units at different spacings to cater to the different weights in water of each of these pipelines) needed to be pulled through a crocodile and snake-infested swamp for the Angola LNG project by French contractor Spiecapag. To allow for the release of the inflatable buoyancy units at the end of the pull without anyone needing to get wet, or risk getting bitten, Seacatch quick release hooks were introduced into the rigging connecting each unit to the pipeline, to be triggered from a workboat via a lanyard secured to the top of each unit.

But it is not just on classic rigid oil and gas pipelines that the principles of air-filled bags are bringing operational advantages to installation contractors around the world. They have been used on high-density polyethylene pipes as well as in applications such as draught reduction and uprighting jackets.

## Conclusions

Using inflatable buoyancy units on shore approach work could save contractors time and money on storage, transport, handling, rigging, and retrieval compared to conventional steel or foam-filled plastic buoyancy, as well as decreasing the risk profile to divers and workboats – and is thus worthy of consideration by those who have yet to assess the benefits of this technology for themselves.

An ever-increasing number of contractors now adopting this kind of solution, some uncertified. On the balance of probabilities, bags which carry certification relating to their proven factors of safety and come with a track record of use on such projects are much less liable to result in lost time, lost time which could the cost savings made at point of purchase. OE

*__Chris Sparrow__ graduated with a BA Honors degree from the University of Durham, UK, in 1995, and has worked in International Sales and Marketing ever since. His early career was with Fluke Corp. within the field of industrial electronics. He has specialized in offshore flotation since 2002, when he joined Fendercare to front up their Hippo Marine solid buoyancy division. Chris joined Unique Seaflex in March 2013.*

# Spotlight on Latin America

**Heather Saucier examines the effect of regional energy policies on Latin America's rich untapped resources, estimated to be some 126 billion bo and 679 Tcf of natural gas, a large majority of which is offshore.**

**Pleistocene eolianite on the coast of Cancun, Quintana Roo, Mexico.**
Photo by Christopher Schenk of the US Geological Survey.

In its latest assessment of undiscovered, conventional oil and gas resources in South America and the Caribbean, the US Geological Survey (USGS) released attractive numbers. Of an estimated means of 126 billion bo and 679 Tcf of natural gas in 31 geologic provinces, a large majority is offshore.

"I think those numbers are rather substantial," said Christopher Schenk, a Denver-based geologist who has overseen the USGS' South American and Caribbean assessments for nearly 20 years, including its most recent 2012 assessment. "The big resources there are offshore."

But are they worth anything?

"All those resources are of no value unless the countries in which they are located have energy policies and investment models that allow international oil companies to come in and monetize those resources," said Jorge Piñon, director of the Latin America and Caribbean Energy Program of the Jackson School of Geosciences at the University of Texas at Austin. "The geologist finds the oil, but the petroleum engineers have to come and get it out. The only way to be successful is to work within an investment model that allows them to do their work."

**Jorge Piñon**

Some operators – such as BG Group, Statoil, BP, Chevron and Royal Dutch Shell – are managing to make offshore plays economically viable despite the moving targets of some countries' energy policies, which can change agreements mid-game regarding royalties, taxes, repatriation of dividends and local content requirements.

Piñon – who runs a program that encourages consistent fiscal policies in countries that ironically need their resources exploited the most – is working to pave a smoother path for both host countries and operators. If dealt a fair deck, third party investors could bring millions of people long-term security and improved quality of life, he said.

## Resources galore

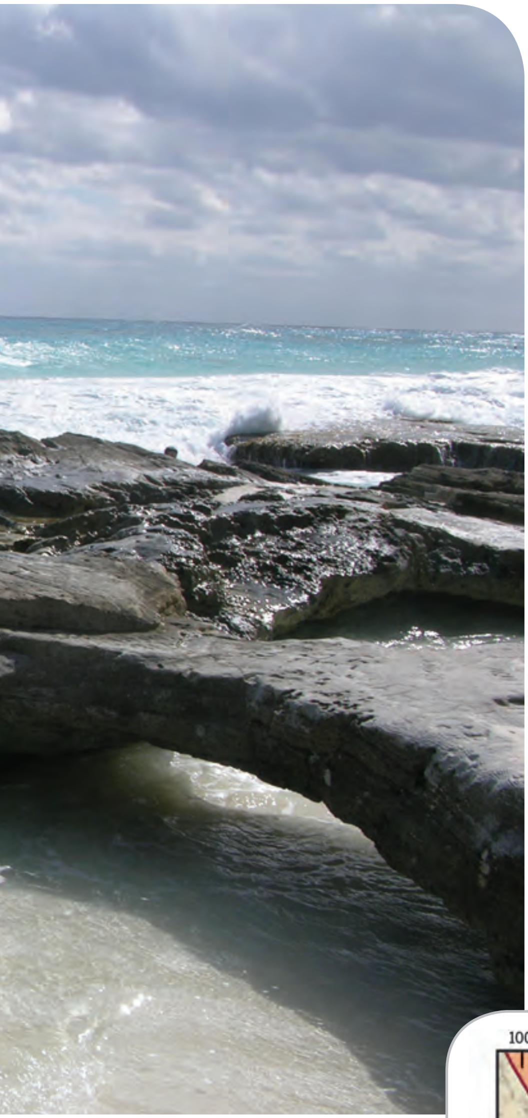
Next to offshore areas in the Arctic and East Africa, offshore South America and the Caribbean could be the most hydrocarbon rich, yet underexplored areas on the globe.

For the past several years, Brazil's Campos and Santos basins have been the hottest subsalt plays for offshore development on the continent. Yet, according to USGS estimates, they are far from being tapped out – containing a means of 14.7 and 59.7 billion bo undiscovered, respectively.

Hiding in the shadows is the underexplored Guyana-Suriname Basin off the north coast of South America and estimated to contain a healthy mean of 13.6 billion bo. It is trailed by another underexplored basin, the Falklands, with an estimated mean of 5.3 billion bo.

"All along we've been saying there is potential in the Falklands," Schenk said, likening the basin to offshore French Guiana, which went underexplored for years until 2011 when Tullow Oil announced a discovery of 236ft of net oil pay from its Zaedyus exploration well.

The virtually untouched Salado-Punta del Este Basin, which is farther south down the Brazilian coast and does not contain salt structures, is estimated to contain a mean of 2 billion bo undiscovered. "It has potential," Schenk said. "Very little



drilling has been done there."

The North Cuba Basin of the Greater Antilles Deformed Belt also holds promise with an estimated mean of 4.7 billion bo undiscovered.

Although Colombia is most known for its onshore resources, an estimated mean of 2.4 Tcf of undiscovered natural gas lies in the Guajira Basin, Schenk added. "A lot of companies feel that oil is more economical than gas, but gas is becoming more economical around the world."

Venezuela, in partnership with Eni and Repsol, is currently developing its offshore Perla gas field, which has been reported to contain reserves of up to 16 Tcf of natural gas in the Cardon IV block in the Gulf of Venezuela.

The Santos Basin is estimated to contain a mean of 62.3 Tcf of undiscovered gas, and the Falklands Basin is estimated to contain a mean of 39 Tcf, Schenk said.

"The resources in these areas are strictly related to the geological history of these areas," Schenk said, referring to the rifting period when South America broke apart from Africa during the Mesozoic era and created rift basins, salt deposits and the deposition of other sediments, soil and rocks. "It's all geology, really, when you come down to it."

## The right shovel

Although the geology may be present for lucrative discoveries, politics can sometimes trump science, leaving valuable resources in the ground, Piñon said.

"Those resources have zero value underground," he said. "You need a shovel – the right shovel – to get them out."

For Piñon, that shovel contains four important parts:

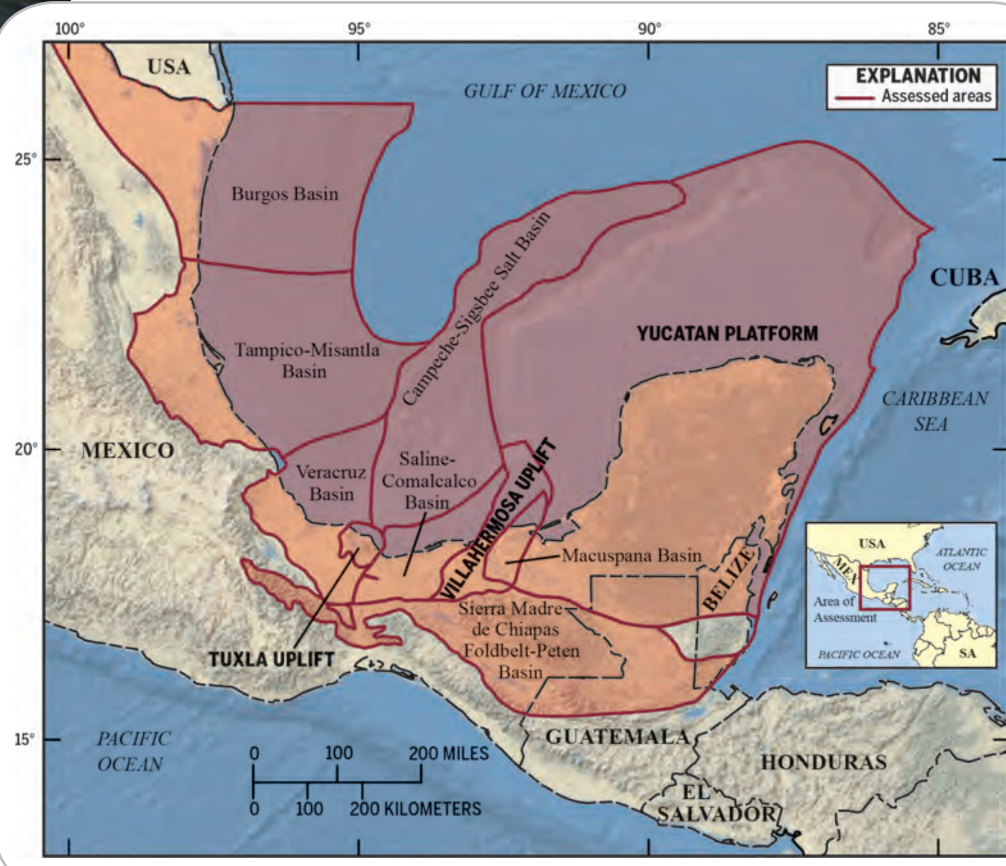
- Oil prices of a minimum of $70/bbl for conventional oil
- A vast amount of capital to invest in costly offshore drilling
- The right technology to explore and develop the area's unique basin make-up
- A sound and consistent investment model of the host county

"The model has to be open, transparent and fair. It has to give companies an acceptable rate of return for them to take a risk, either geologically or politically," he said. "Companies are going to invest where the geology is proven, but they will also look at where they have a high probability of being able to get an acceptable rate of return over a long period of time – 10 to 25 years. They need to invest in a country with a proven track record – not one that changes its policies every five years, or when the price of oil goes up says, 'We don't need you anymore. Go home.'"

Historically, common deal-breakers have included:

- Changing royalty agreements
- Upping concessions yet still requiring third party investors to act as operators
- Raising taxes on produced oil, among other assets
- Increasing local content requirements – often creating a bottleneck in countries that lack the technology to explore and exploit a play

It has been widely reported that assets of ExxonMobil and




**Locations of 10 priority geologic provinces of Mexico, Guatemala, and Belize assessed in 2012 by the US Geological Survey for undiscovered, conventional oil and gas resources.**
Courtesy of the US Geological Survey.

**Cliffs of carbonate rock along the east coast of the island of Barbados.**
Photo by Christopher Schenk of the US Geological Survey.

ConocoPhillips in Venezuela were expropriated in 2007 when the companies refused to restructure their holdings to give the country's oil company, PDVSA, more control.

While international operators have had issues in countries such as Venezuela, Ecuador, Argentina and, at times, Brazil, both Colombia and Trinidad and Tobago serve as the "poster children" for fair business climates by using independent regulatory agencies, Piñon said.

Colombia will surpass 1 billion b/d in production this year, he said, pointing out that the country has a solid set of rules on the table.

"Colombia has seen a dramatic increase in oil, natural gas, and coal production in recent years after the implementation of a series of regulatory reforms," reported the US Energy Information Administration. "Colombia's oil production has increased since 2008 because of increased exploration and development. New exploration and development were spurred by regulatory reform."

On the other hand, for the past 10 years, Venezuela "has been stuck" at 2.5 billion b/d, Piñon said.

"Deepwater, subsalt, shale – the industry has the technology to develop those resources. But you can't invest in a country that doesn't play consistently. It's like going to Vegas and in the middle of a big hand, the dealer changes the rules of the game."

### Mexico moves in

As Mexico prepares to open its doors to international investors in its Round One of bidding expected 1Q 2015, its open and transparent policies could serve as a major impetus for countries south of its border to follow suit.

"Now, other South American countries might have to become more competitive in their investment models to attract international oil companies," Piñon said. "Mexico is closer, has long-standing political and trade relationships with the US and Canada, and it has a common geology, particularly in the deepwater Gulf of Mexico and cross-border shale formations."

Deepwater Mexico is thought to contain 27.8 billion bo, according to the National Hydrocarbons Commission.

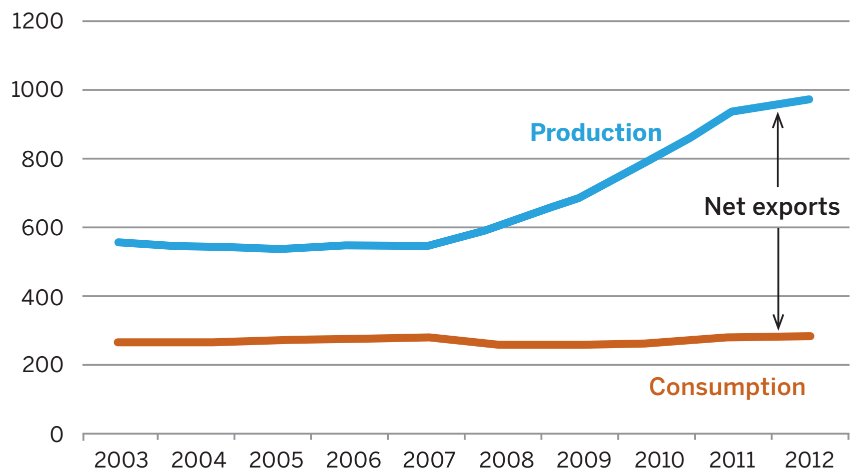
Familiar to many operators are several offshore plays that could give South America's resources a run for their money.

**Juan Antonio Cuevas Leree**

The Perdido Fold Belt in Mexican waters – in the offshore Burgos Basin – are believed to contain larger ridge and salt structures than in the US, said Juan Antonio Cuevas Leree, a Mexico City-based geological consultant and former exploration manager for Mexico's North and South Region at Petróleos Mexicanos (Pemex). "There could be more production there than in the US. The area is huge and there

**Colombia's oil production and consumption**

Thousand barrels per day




Source: EIA.

has been very little exploration in the northern part," he said.

The Mexican Ridges Fold Belt in the Tampico-Misantla Basin has remained essentially untouched, as it is exposed in the sea floor and does not contain ideal seals. However, a deep drilling operation into turbidite channels and fans could change the fate of this play, Cuevas Leree said.

The Catemaco Fold Belt, located in deep water just in front of the Veracruz Basin, is known to contain gas and light oil. Furthermore, the underexplored Campeche Salt Basin could also attract investors, Cuevas Leree said, as several million barrels of extra heavy oil have already been discovered there by Pemex.

Although the Campeche Basin has been active for years, the USGS estimates that a mean of 2.9 billion bo remain undiscovered. "The Campeche is not done," Schenk said.

### Short-term vs. Long-term

In the wake of Mexico's welcoming of international investors, Piñon said he would not be surprised if Brazil stepped up to the plate in the face of greater competition.

"Brazil is important to all investors because of its large resource and reserve base. The government has decided that Petrobras can handle – in our opinion – more than they can chew. This has been a mistake proven in Petrobras' recent performance," said Piñon of the company's ailing refining unit, languishing production rates, and plummeting stock prices.

"I would not be surprised if sometime in the near future Brazil changes current investment rules and makes them more attractive," he added. "Capital from foreign investors is desperately needed for them to monetize their deepwater resources and make them commercially viable."

Overhauling business models is essential for South American countries to extract their resources. Oil and gas from South America, Canada, the United States and Mexico comprise one-third of the world's reserves, Piñon said.

It's really a matter of being able to help certain governments see the benefits of rearranging the rules for the sake of long-term strategy rather than meeting immediate needs.

"I understand what their short-term challenges are. They need hospitals, schools, employment. People are rioting in the streets because of the price of food and high inflation. Those are short-term political problems to face, and the only bucket in which you can put your hand is the oil and gas sector," Piñon said. "But by robbing Peter to pay Paul, you are limiting the long-term growth of industry for short-term political benefits."

The work required to help change international energy policies can be likened to a revolving door – a continuous conversation with academics, opinion leaders, scientists, leaders in the private and public sectors, multilateral international organizations, and others, Piñon said.

"National leaders of host countries, political ideologies, and economic conditions are constantly in flux," he said. "They all put pressure on changing the course of sound energy policies. So our work is an ongoing process of striving for improvement." OE

# Big spending needs investment

**Brazil has big plans as it sets its sight on increasing oil exports – but it will need investment in technology as it moves into ever deeper waters. Elaine Maslin reports from Subsea Expo.**

**Various vessels await deployment in Guanabara Bay near Niterói.**
Photos by Audrey Leon/OE.

Brazil's offshore sector, in plain numbers, is eye-watering. In 2012, the country already has some 37% of the world installed Xmas trees, a figure expected to rise to 44% by 2020.

In 2012, the country had 21% of the global FPSO fleet, a number also on the rise and expected to hit 26% by 2020.

The figures were outlined by Marcelo Vertis, undersecretary, Secretariat of Economic Development and Energy, Governo Do Rio de Janeiro, at Subsea Expo in Aberdeen, in February.

He cited International Energy Agency World Energy Outlook 2013 figures which say up to 2030 US$90 billion will be spent on the energy sector in Brazil, with 71% of that total, or $51 billion, being spent in the oil and gas sector (the majority, or 64% of that being on gas).

"This is an incredible amount of investment and for a long time," Vertis says. If the investment happens, Brazil should be exporting some 3 MMb/d by 2015, with the same amount being used for domestic consumption.

Chris Wall, an expert in international trade, who led the UK Trade and Investment session during Subsea Expo, said: "It is Brazil's intention over the next few years to become a net exporter of oil." But, to meet their goals they need co-collaboration with international companies. In Rio State, a subsea cluster has been developed, just for this purpose.

Rio Negocios, an inward investment agency, has been developing relationships with their counter parts in other countries, such as Subsea UK, which runs Subsea Expo, NCE Subsea, in Norway, and others, to attract international companies to Brazil. But, it's not necessarily smooth running, even without local content rules. Businesses need to be competitive and help the local supply chain become competitive.

**The FPSO *Cidade de São Paulo*, currently deployed in the Sapinhoá field offshore Brazil for Petrobras.**
Photo from BG Group.

The event heard that Brazilian foundry Grupo Metal, which supplies Shell, but has gaps in its capabilities, is working with Shell Brazil and UKTI to find international partners to plug those gaps.

The investment target still stands, however. "These are very impressive figures for a country, both for the commercial budget and geopolitically," says Vertis, not least as the country is in the wider Atlantic basin, putting it in the same ring as America and Europe, he says – not the Far East or Middle East, but "calm waters."

"For the subsea industry, the Brazilian discoveries offshore, in the ultra-deep offshore, technology and subsea equipment will be very important," he says. "Today, 25% of all exploration and production spending in Brazil is in the subsea equipment,

**Ships line up near the Rio-Niterói Bridge, crossing Guanabara Bay, linking the cities of Rio de Janeiro and Niterói.**

and that might increase in our view. It is a huge opportunity for developing the supply chain. That is what we wish."

The government in Rio undertook a survey to find out what particular services and equipment requirements are needed. The list included forged alloys, coatings, fasteners and special bolts, fittings, subsea metallic structures, fine machining, subsea valves, panels and multiplexed control systems, ROVs and UPVs, smart actuators, pipe bending and cladding, polymers for flexible lines, metallic structures for flexibles.

Vertis says while the tier 1 suppliers – FMC Technologies, Aker Solutions, GE, Schlumberger, etc. – are already in country, they would like to see the tier 2 and 3 contractors come in. "That is what the government of Rio wants," he says, and to encourage more firms in.

There have already been some recent moves into Brazil by UK firms, including BEL Valves, which moved into São Paulo state, and cables firm JDR, which moved to Macaé. Rolls Royce recently opened test and assembly facilities for gas turbines in Brazil. OE

# Buoy supported riser installed

Automation systems provider Cougar Automation has developed and commissioned a control system for Balltec to use on the first buoy supported riser (BSR) system installed on Brazil's Guara-Lula project.

Guara-Lula is the largest engineering, procurement, installation and commissioning subsea umbilicals, risers and flowlines contract ever to be awarded in Brazil.

Operated by Petrobras and located in Santos Basin about 100mi off the coast of Rio de Janeiro, the BSR system consists

**Buoy supported riser tether adjustment, using a linear chain tensioner.**
Photos from Cougar Automation.

## at Guara-Lula

of four submerged buoys each weighing approximately 2000-tonne, laying about 300m below sea level.

Cougar Automation was commissioned by Balltec to design a dedicated control and automation system, consisting of a surface-mounted primary control that would control the movement of the buoy support system via tether adjustment, using a linear chain tensioner. This was required in order to manage the tension in the risers.

The system allows surface control of the subsea tensioner system via an ROV. Once overboarded, the ROV facilitates establishment of the data pathway linking the surface control to the subsea control modules. The surface control is then used to effect buoy movement as required

The system enables the controller to make adjustments to the position of the buoy using the tensioners, via visual monitoring and control using surface-mounted touch-screen human machine interfaces.

The surface control system is also able to automatically interrogate and identify the exact tensioner it is connected to, as well as generating advanced statistical reporting, operational and historical data for convenient trouble-shooting and audits.

The control system can also make rapid decisions in real-time to protect the equipment and facilitate safe operation; which a human would be incapable of. This includes highlighting of any anomalies to the operator and the generation of events during normal operation. This ensures that the system can be protected against any damage quickly and efficiently. ■

# Expanding on IIoT

**Industrial Internet of Things is out there, but 'work needs to be done.'**

By Gregory Hale

Industrial Internet of Things (IIot) is nebulous term bandied about in just about any conversation when it comes to automation, when in reality, the level of communication already conducted on a daily basis for the past decade or so has been a precursor to the advanced technology on the verge of becoming the industry norm.

With sensors becoming ubiquitous and data rushing through the enterprise like a raging creek after a torrential spring rainstorm, properly using Big Data and putting everything in context becomes paramount for users.

"Today, we need to hire a slew of mathematicians to help us out," said Chet Mroz, chief executive at Yokogawa North America. "There are about three times more data points coming in." There will be even more data coming online as Mroz said there will be direct integration of the distributed control system to subsea.

While IIoT is not a complete package yet, there are companies employing pieces to garner additional knowledge and productivity. "There is a lot of IIoT out there, but there is a lot of work that needs to be done," said Brian Phillippi, one of the managers on the C Series IO products at Austin, Texas-based National Instruments. "A lot of companies already are taking in a lot of data."

## Holding Back IIoT

There are some big issues, however, preventing full adoption of the IIoT.

One is finding the right people with the correct skill set. "Some of the hottest jobs right now are the data scientists that can make sense of all the data," Phillippi said. "Another big one in terms of adoption of the IIoT is going to be security. Every week now, we are hearing about some kind of hack going on and I think the industry as a whole has to get better about embedded security. The third thing causing a lot of problems of IIoT is the ability of everything being able to communicate on a single standard. On the commercial IoT they have a really good way to communicate with the regular Internet. That won't cut it on the industrial side of things because of the determinism that is needed for the industrial environment."

"IIoT is just about taking a thing, automating that thing and adding value to the Cloud and the Internet," said Jamie Smith, National Instruments' director of embedded systems product management, quoting a conference keynote speaker discussing the IIoT. "If you boil it down to those three simple steps, I think a lot of companies can start. They can look for things they want to automate and then they can add value through the cloud and the Internet."

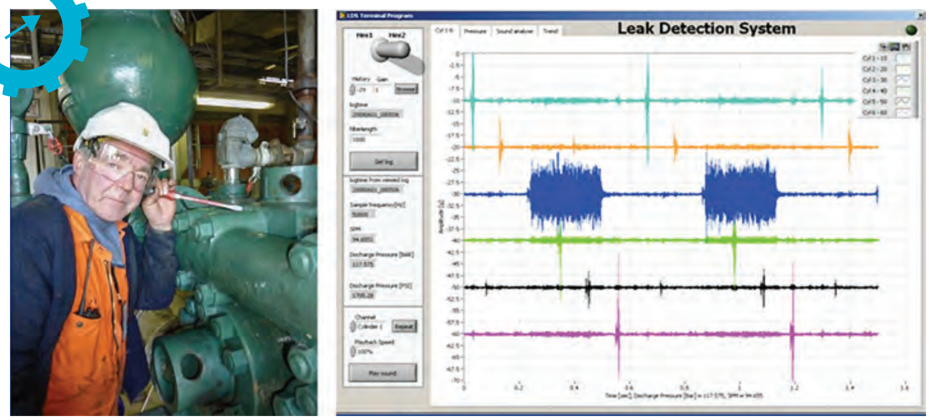
A case in point is condition monitoring and big analog data analytics that allows for a predictive maintenance plan.

## Monitoring Mud Pumps

National Oilwell Varco (NOV) is a perfect example. The oil services giant was dealing with trying to solve issues with mud pumps that circulate drilling fluids. Mud pumps stabilize pressure and support the well during the drilling process and drilling fluids provide friction reduction and a means to remove cuttings. NOV created a leak detection system for hex pumps. The hex mud pump relies on six pistons, six suction valves, and six discharge valves. A rotating asymmetric cam drives the six pistons, according to Pål Jacob Nessjøen, formerly with NOV and now with Kelda Drilling Controls.

"Previously, they were listening to these pumps and trying to understand if there was a leak," Phillippi said. "Sometimes they would put a

screwdriver on the pump and listen to the vibration on the screwdriver. When you are talking about these big pumps that cost thousands and thousands of dollars, that wasn't a good enough solution for them. NOV implemented a condition-based monitoring system so they can, not only know when they have a problem, but be able to pinpoint where exactly in the pump the seal is actually leaking and having a problem."




**Left: A screwdriver is the driving force behind the former way of detecting a leak in a pump. Right: A screen shot showing NOV's leak detection system.** Images from NOV.

Learning about a valve issue often occurs when the leaks are so severe they induce large discharge pressure fluctuations and create washout damages. "When a severe leak is detected, we localize it manually by listening to the fluid modules while the pump is running, but it is difficult to uniquely localize the leak and distinguish between a suction valve leak and a discharge valve leak," Nessjøen said.

When it comes to valve leaks, they often develop quickly so manual detection gives very little time to prepare for changing out a problematic valve. In addition, if the source of the leak is not clear, finding out where it came from ends up being time consuming.

That is where a remote system to detect and determine the location of the leak comes into play.

Using a now-patented system, Nessjøen and NOV's Age Kyllingstad found during a vibration monitoring project for hex pumps, it was possible to detect leaks using accelerometers. NOV engineers recorded vibrations at different locations, on the pump and on the discharge line, along with suction pressure, discharge pressure, and pump speeds for different pump conditions.

When at one point they noticed a vibration signature changed during a 15-minute time frame, they knew a leak was developing.

## Remote Monitoring

That was the beginning of a true predictive maintenance situation. They were then able to perform more tests and they determined discharge valve 2 had a severe leak.

Based on that experience and some further testing, they ultimately included this condition-based maintenance system as a standard feature on all hex pumps. They developed the system as a stand-alone module to add to the existing hex pump control system. It consists of the following components: Accelerometers (one per valve block), a proximity sensor picking up pump speed and phase, a discharge pressure sensor, an embedded monitoring system, signal processing software and alarm logics.

Now they are able to remotely verify leaks detected automatically by signal processing. The operator can do this by: Viewing and interpreting the vibration signals directly from graphs; selectively listening to the recorded acceleration signals as audio signals to hear the leak sound; checking to see if the mean discharge pressure is stable or dropping, and seeing if the lowest pressure harmonics are growing.

Based on the field experience of the new leak detection system, NOV found the leak detection method offers advantages over current practices, including:

- High sensitivity for early leak detection and localization
- Remote, continuous, and computer-based pump monitoring
- Increased safety through less human exposure to hazardous environments
- Multiple leak detection and localization (in hex pumps)
- Reduced maintenance time and cost because leaky valve(s) are localized before the valve exchange jobs start
- Easy to retrofit existing pumps because accelerometers can be attached by glue, magnets, or tape

IIoT is continuing to grow offshore as more operators are understanding and finding opportunities to incorporate more knowledge and productivity into the system.

"There is more adoption now and it is on the condition monitoring side of things to begin with," Phillippi said, "but we also see the value of that on the control side as well." OE

***Gregory Hale*** *is the Editor and Founder of Industrial Safety and Security Source (ISSSource.com) and is the Contributing Automation Editor at Offshore Engineer.*

# Activity

## Next generation

**The Offshore Technology Conference returns to Houston again this May, this time with a few more tricks up its sleeve.**



After bringing the latest technology and relevant discussion to people from all over the globe for over 45 years, it seems almost obtuse to say the latest installment of the Offshore Technology Conference is the next big thing, and yet with each edition of the show, it gets larger and larger. And the 2015 show will be no exception.

New this year, OTC will feature an event called d5, slated for Friday 8 May, aimed at exposing attendees to disruptive technologies from other industries. This desire to open the oil and gas industry to technology from other industries also spread to the technical presentations.

On Wednesday, 6 May, there will be a session presenting space technologies for the offshore deepwater industry that is sure to be popular with the kid in all of us. Speakers will include experts from NASA's Johnson Space Center, NASA's Jet Propulsion Lab, the California Institute of Technology, and University of California, Santa Barbara. Oceaneering International will also be on hand to present a case study on testing the company has done at NASA's Neutral Buoyancy Laboratory in Houston.

### OTC 2014 by the numbers

**108,300** – The number of attendees OTC attracted
**130 –** The number of countries OTC attendees represented
**2568 –** The number of exhibiting companies
**680,025sq ft** – The amount of exhibit space, including the outdoor portions
**308** - Technical papers presented over four days
**12** – Sponsoring organizations

Other technical highlights include presentations on CLOV Angola, Ichthys LNG, and the Gulfstar One floating production system.

The conference kicks off on Sunday 3 May with the annual dinner, which recognizes the OTC Distinguished Achievement Award recipients. This year's recipients are Elmer (Bud) Danenberger – for his contributions to offshore safety and environmental protection; Petrobras – for the Brazilian national's work in pre-salt, implementation of ultra-deepwater solutions and setting new water depth records; and Ray R. Ayers, who won the Heritage award in recognition of his over 50 years in offshore research and development contributions to the industry through joint-industry programs he formed.

The 2015 dinner, held at NRG Stadium, will raise funds for the IPAA/PESA Energy Education Center for the benefit of the Energy Institute High School. Opened in August 2013, the Energy Institute a new school based in Houston for grades 9–12. Students work within one of the three pathways—geosciences, energy alternatives, and offshore technology—with a core curriculum focused on STEM subjects.

This year's OTC boasts 12 sponsoring organizations, including: American Association of Petroleum Geologists (AAPG), American Institute of Chemical Engineers (AIChE), American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME), American Society of Civil Engineers (ASCE), American Society of Mechanical Engineers (ASME), Institute of Electrical and Electronics Engineers - Oceanic Engineering Society (IEEE-OES), Marine Technology Society (MTS), Society of Exploration Geophysicists (SEG), Society for Mining, Metallurgy, and Exploration Inc. (SME), Society of Naval Architects and Marine Engineers (SNAME), Society of Petroleum Engineers (SPE), and The Minerals, Metals and Materials Society (TMS).

There are 10 supporting organizations this year, including: American Association of Drilling Engineers (AADE), American Petroleum Institute (API), Association of Energy Service Companies (AESC), ASTM International Center for Offshore Safety (COS), Independent Petroleum Association of America (IPAA), Institute of Marine Engineering, Science and Technology (IMarEST), International Marine Contractors Association (IMCA), International Society of Automation (ISA), National Ocean Industries Association (NOIA), and Research Partnership to Secure Energy for America (RPSEA).

OTC takes place 4-7 May 2015 at Houston's NRG Park complex. For more information, including full conference program and events, visit: 2015.otcnet.org

# NOV

Every day, the oil and gas industry's best minds put more than 150 years of experience to work to help our customers achieve lasting success.

## Through our broad capabilities and vision, our family of companies is positioned and ready to serve the needs of this challenging, evolving industry.

We are a worldwide leader in the design, manufacture and sale of equipment and components used in oil and gas drilling and production operations, and the provision of oilfield services to the uptream oil and gas industry.

## Our Three Business Segments:

**NOV Rig Systems** makes and supports the world's most advanced drilling solutions. We design, manufacture and sell land rigs, offshore drilling equipment packages, including installation and commissioning services, and drilling rig components that mechanize and automate the rig process and functionality. NOV Rig Systems provides comprehensive aftermarket products and services to support land and offshore rigs and drilling rig components. We're continually pushing our own standards higher to deliver the safest, most efficient and most reliable drilling solutions in the world.

**Offshore | Land | Aftermarket**

**NOV Wellbore Technologies** touches every aspect of the drilling process. We design, manufacture, rent and sell a variety of equipment and technologies used to perform drilling operations, and offer services that optimize their performance. We've brought together the best companies to solve operational challenges from fluid control systems and tubular inspection services, to downhole products and automation solutions. We focus on oil and gas companies and support drilling contractors, oilfield service companies and oilfield rental companies. We understand what Operators are focused on: performance, safety, uptime and environmental impact.

**Drilling and Intervention | Dynamic Drilling Solutions | WellSite Services | IntelliServ | Grant Prideco | Tuboscope**

**NOV Completion & Production Solutions** integrates technologies for well completions and oil and gas production. We design, manufacture and sell equipment and technologies needed for hydraulic fracture stimulation, well intervention and artificial lift systems. In addition, we focus on offshore production with floating production systems and subsea production technologies. In every type of environment, we bring together engineering operational expertise and field-proven solutions with a foundation of safety and risk management that helps you control costs and achieve lasting success.

**Subsea Production Systems | Process and Flow Technologies | Floating Production Systems | XL Systems | Intervention and Stimulation Equipment | Fiber Glass Systems**

Stop by **Booth 3741** during OTC to speak with NOV representatives and learn more about how we are making a difference in our customers' operations.

**nov.com**

# ENHANCING OPERATIONS WITHIN THE OFFSHORE, OIL & GAS ENVIRONMENT

## Case study: Launch & Recovery Systems

The offshore industry is beset by challenges, harsh environment, weight penalties, and difficult maintenance opportunities.

The introduction of Engineered Polymers can deliver significant performance advantages and lifetime cost savings over conventional metallic components.

As an example, a Launch and Recovery System can be considered, these are placed on a vessel deck exposed to the elements. Three specific applications demonstrate the advantages of using Nylacast's engineering solutions.

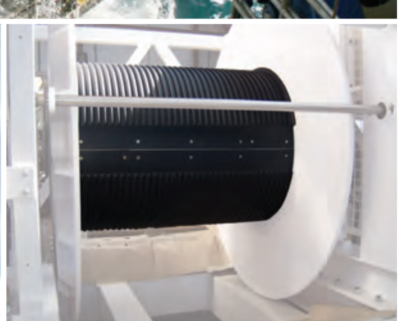
Taking advantage of the low mass, Nylacast sheaves deliver similar load capacity to conventional metal sheaves without the need to paint or to protect from corrosion.

In addition a typical Nylacast sheave will weigh less than half the equivalent metal sheave. Lower mass sheaves lead to less load on the A frame and an increased lifting capacity.

Working with Nylacast to reduce maintenance costs, has lead to the use of Nylacast Nylube for wear pads and sliding bearings. With a bearing life of 25 times that of phosphor bronze, Nylube delivers class leading low friction, reduced friction, and significant reduction in maintenance costs.

Focussing in on the critical nature of rope spooling, Nylacast has a unique solution for the consistent and effective layering of the rope. A Nylacast spooling shell is an excellent low mass alternative to conventional steel shells. Easier installation, lower weight and no requirements to apply any anti corrosion treatment.

Nylacast provide engineered solutions for many applications, contact offshore@nylacast.com or visit www.nylacast.com/offshore

# Activity

## OTC Spotlight Awards reward technological advances

**This year's OTC Spotlight Awards showcases innovation in offshore seismic, drilling, subsea operations, inspection, performance maintenance and monitoring, and more. Congratulations to the recipients!**

### MultiNode all-electric intelligent well system

Baker Hughes' MultiNode provides remote-controlled monitoring and precise control of production zones. The system adjusts to changing reservoir conditions by choking back high-water and high-gas producing zones, balancing production along the lateral.

### Mark IV High-Availability (HA) BOP Control System

Cameron's HA BOP Control System features a three-point of distribution (POD) design option for subsea BOPs to add redundancy for improved the operational availability of the drilling system to as much as 98%.

### Dreamliner

Fishbones' Dreamliner creates an array of targeted small diameter laterals into formations to impact productivity. Numerous laterals are individually but simultaneously drilled by harnessing fluid flow through turbines.

### Annulus Monitoring System

FMC's Annulus Monitoring System provides independent condition monitoring within the subsea wellhead from the onset of drilling. The communication system delivers actionable information to the operator during critical phases of well installation and commissioning from multiple analog or digital sensors within annular locations.

### RezConnect Well Testing System

Halliburton's RezConnect offers full acoustic control of drill-stem testing tools. Downhole samplers, valves, and gauges are controlled in real-time and their status is communicated to the surface.

### Deepwater Pile Dredge

Oceaneering's Deepwater Pile Dredge is an electrically-driven system with pumps that provide water jetting and suction. The jetting provides a 360° pattern to fluidize the soil, and then suction pumps remove the soil.

### Magna Subsea Inspection System

Oceaneering's Magna Subsea Inspection System is a screening inspection tool that assesses the mechanical integrity of assets without disrupting production. The system is ROV-deployable, inspects 360° around the pipe, and provides real-time data of the wall condition.

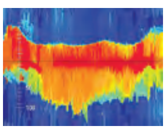
### Multiphase Compressor

OneSubsea's Multiphase Compressor is a wet gas compressor that enables compression of the unprocessed well stream without any need for pre-processing.

### ARCA Chain Connector

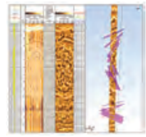
SBM Offshore's ARCA places the chain articulation in the mooring lines allowing them to be recovered for inspection and maintenance, while enabling diverless connection and disconnection.

### GeoSphere reservoir mapping-while-drilling service



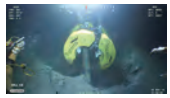
Schlumberger's GeoSphere reservoir mapping-while-drilling service reveals subsurface-bedding and fluid-contact details more than 100ft (30m) from the wellbore. This reservoir-scale view enables operators to adjust landing, reservoir exposure, and refine field development plans using deep-directional measurements enabled by real-time interpretation solutions.

### Quanta Geo photorealistic reservoir geology service



Schlumberger's Quanta Geo photorealistic reservoir geology service provides core-like microresistivity images that visually represent formation geology. These images enable visual identification of facies and determination of directional trends.

### Discovery



Tracerco's Discovery allows operators to externally inspect coated lines for flow assurance and pipeline integrity issues without removing any coatings. Discovery identifies hydrate, wax, asphaltene or scale in real time without production interruption.

### VersaCutter

Versabar's Versacutter delivers a long reciprocating cutting wire up to 20ft below the mudline by jetting, with the wire continuously cutting through the piles and conductors.

### Red Eye Subsea Water-Cut Meter

Weatherford's Red Eye Subsea Water-Cut Meter uses near-infrared absorption to provide water-onset detection, water-cut measurement, and water-to-hydrate inhibitor-ratio measurement. The meter can operate in full three-phase flow streams at any gas-volume fraction and is not affected by changes in salinity.

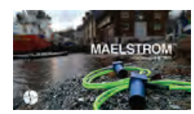
### Total Vibration Monitor with Angular Rate Gyro

The Weatherford Total Vibration Monitor with Angular Rate Gyro is a downhole sensor that provides critical drilling dynamics data in real-time and recorded formats, utilizing MEMS-based (micro-electromechanical system) angular-rate gyro.

### Welltec Annular Barrier (WAB)

The Welltec Annular Barrier (WAB) is an expandable, metal annular barrier engineered and qualified to replace cement in well construction, WAB is cementless primary well barrier qualified to ISO V0 meeting regulatory standards.

### WiSub Maelstrom Pinless Subsea Wet-Mate Connector




WiSub's Maelstrom connector applies inductive coupling for power transfer and microwave communication methods for 100Mbps data rates, while also eliminating the pins from subsea wet-mate connectors.

# Solutions

**Despite the gloom in the offshore industry, the subsea sector was optimistic at this year's Subsea Expo in Aberdeen. Elaine Maslin looks at some new products on the market.**

## XLX-C makes its debut

**F-E-T's Graham Adair with the XLX-C design.** Photo from Forum Energy Technologies.

Forum Energy Technologies (F-E-T) outlined its latest remotely operated vehicle, the work class XLX-C ROV at Subsea Expo.

The unit is a more compact version of the firm's Perry XLX, but with similar capabilities. It has been design from the inside out, starting with an all-bolted construction open central frame design, with removable side protection panels.

Payload can be attached at the front (250kg), side (150kg) and rear of the ROV (300KG). As with other Forum ROVs, the XLX is controlled by the company's own ICE (Integrated Controls Engine), which includes auto-functions, and system diagnostics.

Auto-functions include auto heading survey, auto cruise, with speed adjustment on the fly, and dynamic braking when manual thrust commands are removed. The ICE graphical user

## IWOCS deployment innovation

UK-based Caley Ocean Systems has developed a portable intervention work over control system (IWOCS) deployment system, launched at Subsea Expo in Aberdeen in February.

IWOCS are used to perform testing, control and monitoring functions on subsea equipment, including wellheads and gas lift modules, for example.

Gregor McPherson, sales director at Caley, says traditionally, the IWOCS cable is clipped on to the riser as it is deployed to the subsea wellhead or manifold, a time-consuming process requiring use of an overhead crane and human intervention.

Caley's deployment system is an overboarding system, comprising a 25-tonne overboarding unit (7.75m-long x 4.2m-wide x 3m high) and a 13-tonne reeler (based on a 700m-long umbilical, but weight excluding umbilical) with integrated hydraulic power unit for effective speed control of the umbilical (3.9m-long x 2.4m-wide x 3.4m high).

**Caley Ocean Systems' IWOCS deployment system.**
Image from Caley Ocean Systems.

## FURTHER READING

**Subsea industry leaders** were told not to "waste a good crisis" at Subsea Expo. Read more: www.oedigital.com/component/k2/item/8224-don-t-waste-a-good-crisis

**Proserv was named company of the year** and commercial diving veteran, Alf Leadbitter, from The Underwater Centre in Fort William, received the award for outstanding contribution to the subsea industry, at the 2015 Subsea UK Awards. Read more: www.oedigital.com/component/k2/item/8236-proserv-named-subsea-company-of-the-year

interface enables autospeed, control of high flow valve packs, administrator access and adaptable screen layouts.

The XLX-C has an integrated, easily removable hydraulic power unit, with 147cc and 75cc pumps, providing main and auxiliary systems, and a new 4.16kV, 150hp motor, and all pump controls, system filters and reservoirs are built in with minimal pipework and hoses. The hydraulics have been rationalized, comprising a 10 station low flow valve pack, two bi-directional station high flow valve pack and eight station (two per ROV) thruster valve pack, and the manifolds repositioned to give free deck space.

The termination junction box is in a removable can, providing 360° access to wiring and fiber connections. The power junction box contains two transformers (with no high voltage terminals).

The unit has 150HP, compared to the XLX's 200HP, and is 2.8 x 1.9 x 1.7m, requiring 9.5-tonne launch and recovery capacity, compared to 12-tonne for the XLX. The XLX-C's payload is 250kg, with 850kg bollard pull, Sea State 6 certification and 3000m depth rating.

Graham Adair, vice-president sales and marketing at Forum said: "The XLX-C is more compact so it takes up less deck space on-board a vessel. The hydraulic systems and electrical sub-systems have been rationalized while functionality and reliability have increased."

Manufactured at Forum's Kirkbymoorside facility, in northern England, the first of six XLX-C ROVs, ordered by Subsea 7 will be delivered in March. The six units are destined for three new-build pipelay support vessels, due to enter the Brazilian market. ▪

These are mounted on a portable skid, to create a single portable package.

Using Caley's system, once deployed, the IWOCS will then either sit on the seabed next to the subsea controls, or will be hung on a buoyancy supported lazy S, offset from the worksite, before being connected via a jumper to the subsea equipment. Using Caley's system, it could also be deployed from a separate vessel.

There is no limit to the depth the umbilical can be deployed to, provided the umbilical can support its own outboard weight in the water. Depending on the outboard load, line speed and level of redundancy, power rating can typically range from (but isn't limited to) an 18.5kW to 37kW hydraulic power unit, based on typical operational speeds and loads. The system is currently designed to go down to 1500m, up to sea state 6. ▪

People

# Spotlight

By Elaine Maslin

## Lessons learned with Kristian Siem

Kristian Siem was early in his career when in 1978, with the market at rock bottom, he formed an investment group to take a punt on a rig. Now 65, the founder and chairman of Siem Industries, and chairman of Subsea 7 and Siem Capital, as well as director of a host of other companies, has not looked back… much. Before starting his own business career, Siem held several management positions with the Fred. Olsen Group in the US and Norway. He spoke to OE.

**When did you first see the potential in the subsea technology and services market and has it exceeded your expectations?**

DSND, the forerunner of Subsea 7, was in the early 1990s a marine investment company with a diverse portfolio of vessels, including a few dynamically positioned offshore vessels. These were chartered on term contracts to contractors who did the work for the oil companies. We thought the risk would be reduced by working directly with the oil companies and decided to build up a knowhow of project execution. That proved to be even higher risk and we learned the hard way. We now know what we are doing.

**There has been a lot of discussion about how standardization could help address current cost escalation. Is a change in mindset needed to meaningfully implement standardization programs that would help reduce cost?**

Yes, I do think a change in mindset is required and that may be forced through in the present situation where margins are squeezed for all players and particularly the oil companies, which need to find ways to make field developments economical. Some operators have management already with the right mindset, but without sufficient focus on opportunities to reduce cost by standardization and better planning in cooperation with the contractors.

**Are new business models needed to address the changing demands in the sector, as the seabed becomes the new factory floor?**

The trend towards more activity on the seabed will continue and cost is a decisive factor. However, whatever technical solution is chosen, there are opportunities for reducing costs not only by standardization, but also by better coordinated planning between operator and contractor and by avoiding duplication of efforts.


Kristian Siem

**What attracted you to the offshore sector when you invested in the first rig in 1978?**

I had already been working in the offshore sector since 1972 when I started employment in Houston. In 1978 the market was at the bottom, with no employment to be had for drilling rigs. The bottom of the cycle is where the best opportunities are found. Rig values were at the bottom, the oil price was rising, and we believed in the future of the rig industry. 100% financing was obtained based on cash equity sufficient to pay lay up costs for an extended period of time.

**If you could go back to 1978 and do anything differently, what would it be?**

In 1978, when we bought the rig from Viking Offshore, who were virtually bankrupt, due to the non-existent opportunities for employment. The investment was highly speculative and very few were prepared to take the risk to invest. In order to obtain the necessary equity capital for the purchase, we had to accept shareholders who were a mix of unpaid vendors to Viking, whose objective was solely to recover their claims and previous owners who needed to cover their downside through the sale. There was, therefore, a conflict between the shareholders at the outset. Some of us wanted to build a new drilling contractor for the long term and the others wanted a quick profit. The lesson is to align partner interests as much as possible at the outset.

Also, I could have assured better protection for our interest in the agreement with the other shareholders who wanted out quickly. All shareholders made 300% in 8 months, so that was not bad for anyone, but the buyer of the rig still has it in operation and has probably made 10 times the full purchase price in realized profit.

**What have been in the main changes in the industry, particularly in Norway, since the 1970s?**

The activity level has, of course, increased since that time and Norwegians have learned all the required skills of the industry. The negative change in this period is that we have taken on unnecessary large costs, which are peculiar to Norway and not sustainable internationally. OE

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## MEXICO Supplement

# Numerology

## 75,000 bbl

The oil production capacity of Chevron's Big Foot extended-TLP headed to the Gulf of Mexico See page 16.

## 1999

The year the West Deep Delta Marine development came on stream. See page 20.

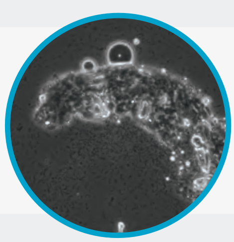
## US$1.2 billion

The amount by which French operator Total plans to reduce operating expenditure this year. See page 31.


## 88 billion bbl

The amount of hydrocarbon recoverable if global efficiency rose 1%. See page 34.

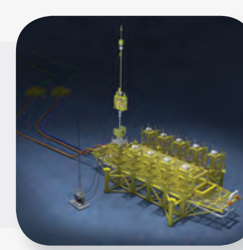
## $10/bbl



The incremental unit cost per barrel associated with the use of MEOR technology. See page 38.

## 1996

The year first oil was achieved through the 10-well subsea template at Pompano field in the US Gulf of Mexico. See page 50.



## 20

The minimum number of wells a year that could be operated using riserless light well intervention techniques. See page 54.

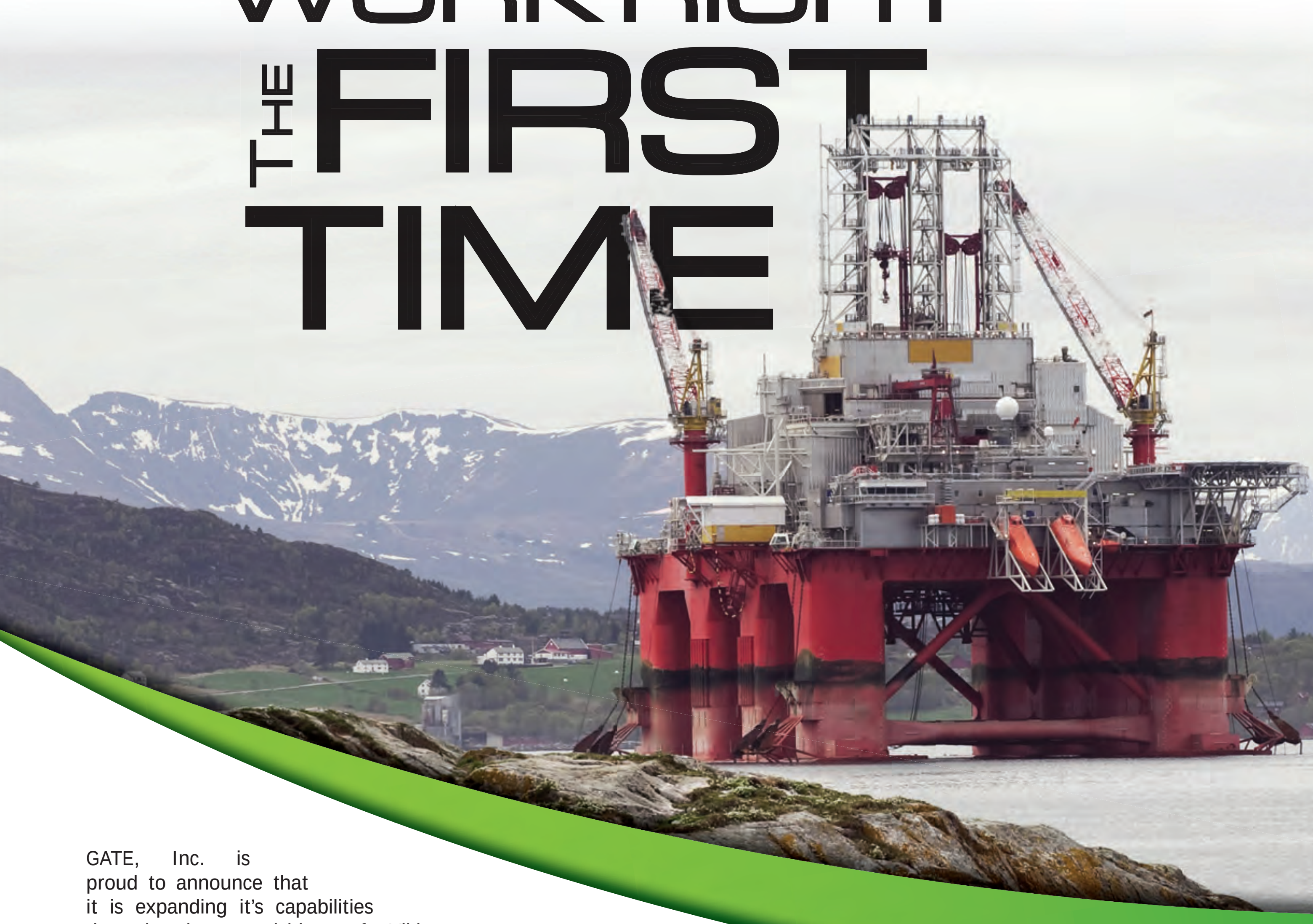
## 679Tcf

The amount of natural gas contained in in 31 geologic provinces in Latin America. See page 62.

## 21%

Of the world's FPSOs are offshore Brazil. See page 66.

# PARTNERING WITH CLIENTS TO MAKE IT WORK RIGHT THE FIRST TIME



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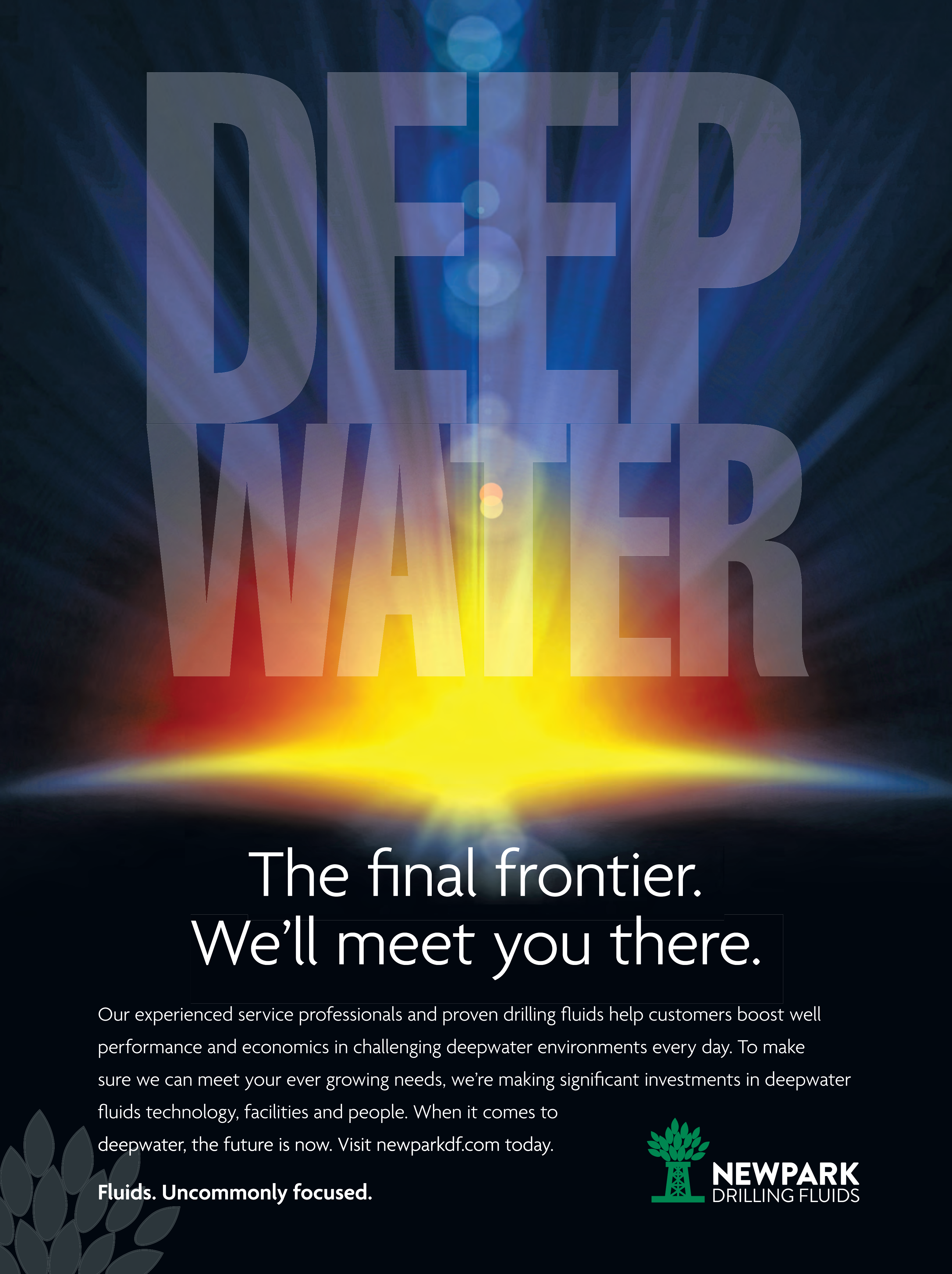
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