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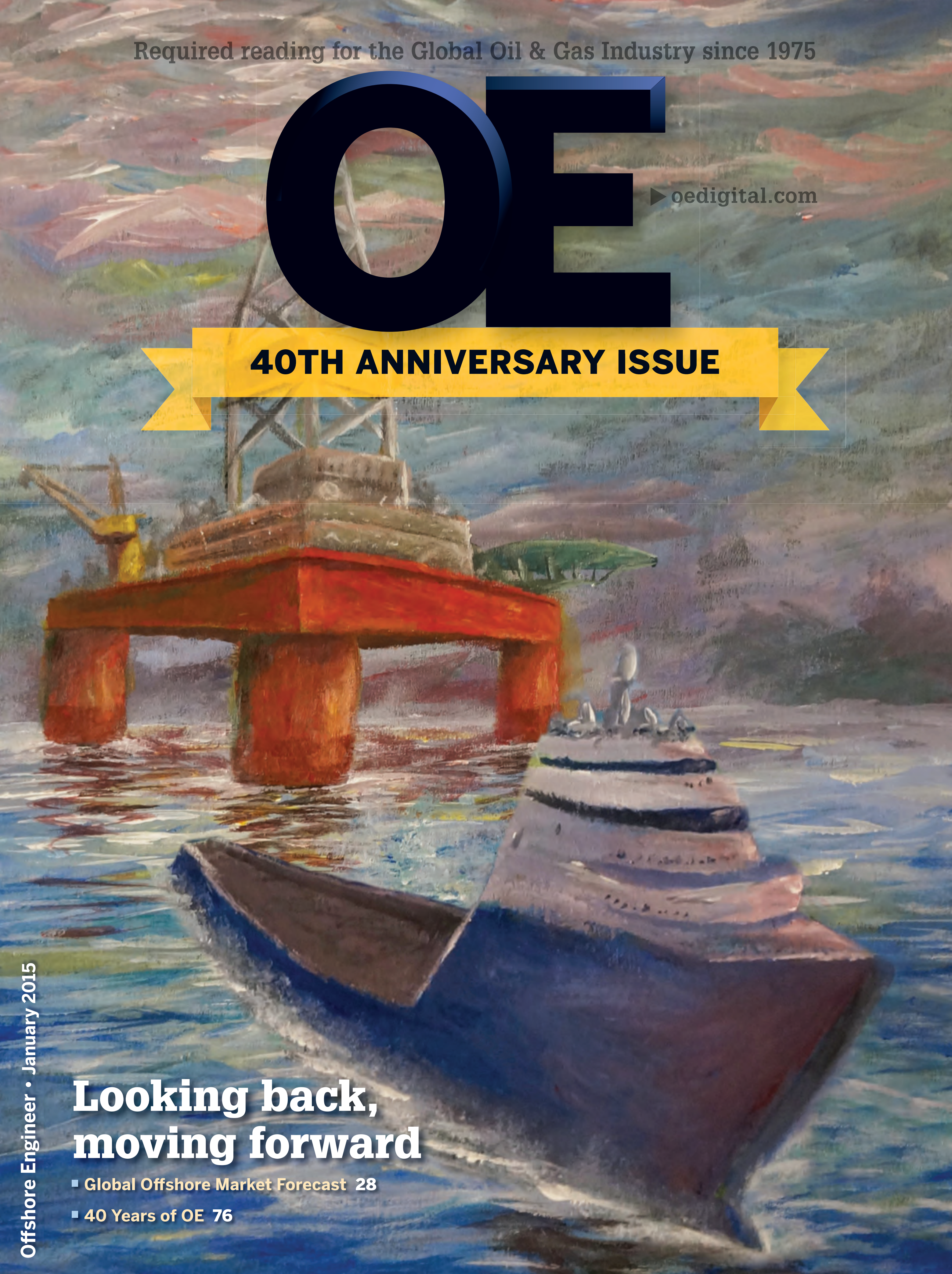
40TH ANNIVERSARY ISSUE



Looking back, moving forward

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- 40 Years of OE 76

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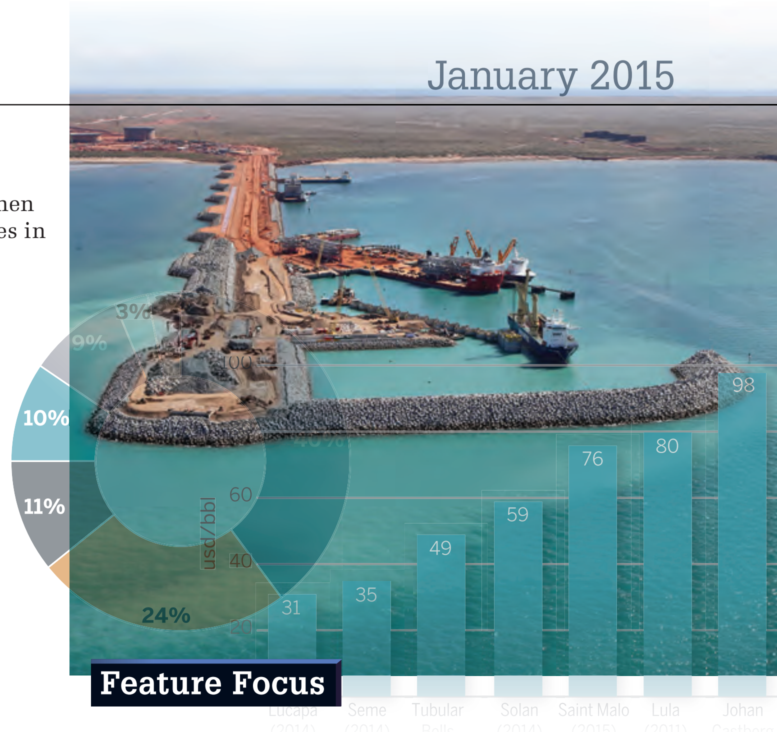

Feature Focus

Global Offshore Market Forecast

ON THE COVER

Next generation. As OE turns 40 this year, we wanted to pay homage to our very first cover depicting Britain's first offshore oil field, Argyll, which similarly turned on its taps in 1975. This portrait, painted by Sage Hansen – a 3D animator at NOV who contributed our June 2014 cover – recalls the scene from 1975 and updates it with more modern, next-generation equipment.

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LET'S WORK.

Volume 40, Number 1 January 2015

Departments & Columns

“What is the biggest challenge facing the global offshore oil and gas industry in 2015?”

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Online Exclusive

Jumpstarting Egypt

Egypt's bid to pay off its mountain of debt to international oil companies and improve contract terms could create a rush of activity to make up for time lost over the past few years, says the former EGAS chairman Mohamed Shoeib. Patrick Werr examines the details.

Photo from BG Group

What's Trending

Big business

- **Woodside buys Apache's LNG stakes**
- **Repsol offers US$8.3B for Talisman**
- **Mexico opens Round 1 bidding**

Photo from Chevron

People

Hopper to head BOEM

Abigail Ross Hopper has been appointed Director of the US Bureau of Ocean Energy Management (BOEM), effective 5 January. Acting Director Walter Cruickshank will continue to serve as BOEM's deputy director.


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Voices

The biggest challenge is how to adapt to the current price environment in a way that does not destroy long-term value. It is likewise as much about understanding the new industry dynamics; to understand and commit to the business opportunities evolving despite a low oil price –instead of only seeing problems.

Jarand Rystad, CEO
Rystad Energy

Outlook. Given the current drop in oil prices, OE asked:

What is the biggest challenge facing the global offshore oil and gas industry in 2015?

The current low oil prices mean that when it comes to determining the probability of success of reservoirs, there's little or no margin for error. Dry wells and expensive investments with limited commercial value must be avoided at all costs. It's therefore more important than ever to utilize all data sources to develop a complete picture of the subsurface and its economic potential. This includes the integration of seismic and Electromagnetic (EM) data – providing significant ROI and generating probabilities of success operators can have confidence in.

Roar Bekker, CEO
EMGS

From a supply chain perspective, it will be the ability to identify which field developments are to proceed into the contracting phases during 2015 against the backdrop of low oil prices. This will be crucial in knowing where to expend resources. Offshore developments, involving FPSOs, for example, are less likely to go forward as operators look to more economic ways of developing resources (Premier's Sea Lion development in the Falklands being a prime example). The supply chain also needs to look at reducing costs with the standardizing of subsea equipment one potential area for saving.

Neil Golding, Head of Oil & Gas
Energy Industries Council

The considerable drop in the price of oil and gas will have a substantial impact on the global economy in 2015, which will result in pricing pressures to those companies servicing the industry. There will be a significant challenge to continue to provide innovative technology, making the necessary capital expenditures, without traditional profit margins. With smaller margins, there will be an inevitable increase of competition, which will hopefully benefit the industry as a whole as we weather this pricing cycle.

Billy Brown, President and CEO
Blackhawk Specialty Tools

Despite the uncertainty in the 2015 market outlook, the demand for energy remains strong. Deepwater environments, such as the Gulf of Mexico, create huge logistical and technological challenges. They also require complex, capital-intensive development programs characterized by continuous cost increases. In 2015 and beyond, operators will be further challenged to look for improvements in drilling efficiency and operational planning to manage development costs while remaining focused on safety and reliability. Trained, competent personnel remain one of the primary factors in project execution and delivery. Retention of these resources is another challenge for operators and for service companies.

Aaron Sinnott
Vice President–Tubular Running Services
Weatherford

Recent oil price declines have accelerated changes in the industry that were already inevitable – increasing standardization, improving efficiency and bringing costs back to sustainable levels. The biggest challenge will be ensuring that competitiveness, competence, quality and capacity is not compromised and that we collaborate with other industry stakeholders to ensure safe, sustainable and cost effective operating environments that protect the industry's long-term viability.
In the UK North Sea, realizing the significant prize of the 24 billion bbl or more remaining in the basin will require assets being in the hands of motivated, competent and focused operators in order to maximize the region's full potential.

Neil McCulloch
President, North Sea
EnQuest

Tight schedules, high activity and complex projects have driven costs up over the last few years, and as the oil price slides to a five-year low, this will have an even greater bearing on global activity in 2015. The industry needs to take a proactive approach to balancing the short-term need for improved margins and long-term need for continued investment in future production. Cutting costs can be achieved best through smarter ways of working. Reduced complexity and standardization to streamline processes, materials and documentation, will all play a role in helping the industry adjust to this lower margin environment.

Elisabeth Tørstad, CEO
DNV GL – Oil & Gas

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

Publisher's Column

Brion Palmer

Blast from the past

The year is **1975**.

Jaws, *The Godfather 2*, *Young Frankenstein*, and *Tommy* are playing at movie theatres. Glen Campbell, David Bowie, and The Captain & Tennille are dominating the radio waves with *Rhinestone Cowboy*, *Fame*, and *Love Will Keep Us Together*, respectively. Plus, a young musician from New Jersey has fans rocking to his newly released album, *Born to Run*.

You might be grooving to *The Hustle* on the dance floor or inspired by Carl Douglas to do some *Kung Fu Fighting*. Or, if at home, you might tune into a new TV show featuring a cast of unknown players (John Belushi, Dan Aykroyd, Chevy Chase, and Gilda Radner) debut on Saturday Night Live.

Muhammad Ali is heavyweight champion of the world after beating Joe Frazier in the Thrilla in Manila. Nicki Lauda is the Formula One World Drivers' Champion driving his Ferrari 312T. Jack Nicklaus tops the PGA Tour in earnings with $298,149 while a future star is born: Tiger Woods.

Two technologies that dominate the business world today also burst onto the scene: personal computers and portable phones. The personal computer is compliments of newly registered trademarked company, Microsoft. Motorola obtains patent for first portable phone. These technologies changed the world. As did BIC, by introducing the first disposable razor. Lastly, Jimmy Hoffa goes missing and is never found or heard from again.

Certainly not missing in action since 1975 is *Offshore Engineer (OE)*. *OE*'s launch coincided with first oil production in the North Sea from the Argyll field, which was quickly followed by the Forties field (first gas in 1967).

Across the pond, construction on the Trans-Alaska Pipeline began. It was truly a new era for the oil and gas industry and *OE* was, has been, and will continue to be there for it all.

The current low oil prices has created uncertainty in the industry. However, the overabundance of supply attributing to low prices is in many ways a testament to the progress of the industry.

Companies are able to extend the life of a field and go to remote regions of the world not previously accessible through advances in technologies.

OE is proud to report on these technologies and the people and companies behind them. Throughout 2015, *OE* will celebrate the last 40 years with special features, charts, and posters recognizing and celebrating key milestones while keeping our readers abreast of the technology, companies, people, and trends impacting the industry today and tomorrow. OE

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John Drake, Ake Group

ThoughtStream

2015 – the global risk outlook

The landscape of risk will continue to change in 2015 for the offshore upstream sector. While new risks are expected to appear, many will remain familiar and consistent with recent years. Some of the biggest concerns are also likely to be eclipsed by potential opportunities.

The biggest area of concern will remain the oil-rich west coast of Africa. The risk of offshore workers contracting Ebola will be statistically low, but the disease outbreak will still have an impact on the sector. Border closures and temporary airline suspensions could disrupt personnel movements while the perception of risk could make it harder for companies to find employees willing to travel to the region. Ongoing pressure on regional healthcare systems could also have an impact on treatment or medevac procedures for non-Ebola issues. Organizations would be well-advised to liaise with their medical evacuation providers in order to plan for potential adverse scenarios in the coming year.

The lack of security on the land will also continue to breed criminality at sea with more attacks expected to target vessels involved in the offshore sector. Personnel will remain at risk of kidnap for ransom while the occasional hijacking of tankers will also have an impact on the downstream sector.

The menace posed by Somali piracy has all but diminished off the east coast of Africa. Once a major threat to shipping and a significant concern for offshore interests, the implementation of proper risk mitigation practices by vessels and improved coordination of international navies has made it a dangerous and unprofitable business venture for the pirates. Nonetheless, the root causes of piracy, such as poverty and an absence of rule of law, have not been tackled in Somalia so the threat may return again.

Piracy will remain a concern in other parts of the world. In Southeast Asia, localized robberies targeting tankers will remain a concern in some areas, particularly the Strait of Malacca, although this will largely harm the downstream sector.

International tensions will also persist in the South China Sea, as national interests compete for ownership of the hydrocarbon-rich region. However, while these tensions are fueled by massive upstream potential and could lead to occasional spats and sporadic clashes, they are not likely to result in a war.

"Eastern Ukraine will remain heavily disputed, with a subsequent impact on the political risk environment in Russia"

Conventional warfare will be much more of an issue in another part of the world: Eastern Ukraine will remain heavily disputed, with a subsequent impact on the political risk environment in Russia. International sanctions on Moscow will hinder efforts to develop the country's emerging upstream Arctic operations. Without foreign finance and technical expertise, the sector will be slow to develop.

Further south, sanctions will continue to block investment in Iran. At this stage, international negotiations are unlikely to open the country up to offshore investment in 2015, but when they do there could be a flood of investment in the offshore upstream sector, in both the Persian Gulf and the Caspian Sea.

Elsewhere in the Caspian region, the lack of rule of law and corruption will hinder investment in places such as Turkmenistan. Upstream investment will also likely remain limited in Kazakhstan until the ill-fated Kashagan project comes back online, but that is not likely until 2016.

The opportunities in the Latin American region are likely to outweigh the risks. Peace talks between the Colombian government and FARC rebels remain at risk of failure. However, even if rebel violence increases and threatens the energy sector onshore it will likely pose little risk to offshore interests. The rebels simply do not have the capacity to target maritime interests, or even the airports and transport routes that energy workers use to travel to and from their work in the country.

The greatest developments in the offshore upstream sector in Latin America are likely to take place in Mexico, where recent energy reforms are expected to provide numerous opportunities. Rather than political risks, which are deemed to be relatively few, the greatest concern in the minds of most risk managers will likely be a potential repeat of the *Deepwater Horizon* disaster. OE

John Drake *runs the intelligence department of international risk mitigation company AKE. Formerly based in AKE's Baghdad office he has also worked in Aberdeen, Hereford and Sri Lanka. His team, based in the Lloyd's of London building, advise companies and organisations on a variety of security, political and travel risk issues around the world.*

Global E&P Briefs

A Jack/St. Malo flows

Chevron's Jack/St. Malo project in the US Gulf of Mexico began production in early December. Production is expected to ramp up over the next several years to 94,000 b/d of crude oil and 21 MMcf/d of natural gas.

The Jack/St. Malo fields are located within 40km of each other in about 7000ft of water in the Walker Ridge area, 450km south of New Orleans.

B Freeport-McMoRan hits Holstein Deep, Dorado pay

Using the *Noble Sam Croft* drillship, 234ft net of Miocene oil pay was encountered at the Freeport-McMoRan's Holstein Deep well, which will increase the net unrisked resource potential from 140 MMboe to 250 MMboe. Using Transocean's *Deepwater Champion* drillship, the Dorado development well encountered 245ft net of Miocene pay.

Freeport-McMoRan plans to tie the Holstein Deep well back to the existing Holstein production facility. The Dorado development well will be the first of three planned subsea tieback wells to the existing Marlin facility.

Holstein Deep is in Green Canyon Block 643, west of the Holstein platform in 3890ft of water. The Dorado development is in Viosca Knoll Block 915 at 3860ft of water.

C Pemex installs compression platform at Tsimin-Xux

Pemex installed the CA-Litoral-A production processing and compression platform in the Tsimin-Xux development project in the Bay of Campeche, in the Gulf of Mexico. The CA-Litoral-A has the capacity to process 200,000 b/d and 600 MMcf/d of natural gas, and came online with a production rate of 100,000b/d, five months before planned.

D Petrobras in Colombian discovery

Petrobras found hydrocarbons in the Orca-1 exploration well in the Tayrona block offshore Colombia. Located 40km north of the coast of Guajira province, Orca-1 marks the first deepwater discovery in the Colombian Caribbean.

The well, which sits in 674m water, reached the expected depth of 4243m and showed the accumulation of natural gas at a depth of 3657m.

The 16,000sq km Tayrona block is operated by Petrobras with 40% interest. Partners include Ecopetrol and Repsol, each with 30% interest.

E CGX to drill Guyana well in 2015

CGX Energy plans to use the Hakuryu-12 jackup rig to spud the Kabukalli-1 exploration well in the Corentyne Block, offshore Guyana.

The rig is currently under construction in Singapore at PPL Shipyard and is due to be completed by the end of January 2015 with delivery expected between April and May 2015. CGX Energy CEO Dewi Jones said the Kabukalli-1 well will test the Upper Cretaceous geologic objectives to an anticipated total depth of 4502m.

F BG, BHP win deepwater blocks off Trinidad

The Ministry of Energy and Energy Affairs (MEEA) for the Republic of Trinidad and Tobago signed two production sharing contracts (PSCs) with a consortium of BHP Billiton and BG International. MEEA estimates resources in the two blocks at 2-7 Tcf of natural gas and 500 MMbo to 2 billion bo.

The contracts include nine-year exploration phases for blocks TTDAA 3 and TTDAA 7, 109,722 and 99,783 hectares, respectively, off the northeast coast of Trinidad, at 1800m water depth. Phase 1 of the exploration period, requires BHP to acquire 2400sq km of 3D seismic data, including 1300sq km in TTDAA 3 and 1100sq km in TTDAA 7.

G Searcher in Irish 2D seismic

Searcher Seismic, in conjunction with project partner MAGE, is conducting a 2D seismic survey off western Ireland. The Echidna Regional Broadband 2D seismic survey comprises about 9000km of high quality, long offset broadband 2D seismic data. It will be the first comprehensive well-tie survey covering the Atlantic Margin off western Ireland. The project will cover the Goban Spur, Porcupine and Slyne basins, and includes well-tie to over 30 exploration wells.

Acquisition is due to start in March 2015, with data expected in time for next the Irish bid round.

H Petronas subsidiary enters Ireland farm-in

PSE Kinsale Energy reached an agreement with Lansdowne Oil & Gas to acquire 80% interest and become operator of SEL 4/07 offshore Ireland. The company will also fund 100% of well drilling costs on the Midleton prospect, and fund Lansdowne's share of the costs of any testing program up to US$2.5 million (net).

I Centrica hits Pegasus West pay

Centrica Energy hit gas at Pegasus West, 150km east of Teesside, in the southern North Sea. The Paragon 391 jackup rig drilled the discovery well in 95ft water, 7km west-southwest of the 43/13b-6Z Pegasus North well.

A drill stem test resulted in a combined flow rate of more than 90 MMcf/d from three Carboniferous intervals. The Pegasus West well has been suspended to assess data and to make a decision on development.

Centrica Energy operates Pegasus with a 55% interest with partners Third Energy (35%) and Atlantic Petroleum (10%).

J Saturn comes up dry

Statoil's final well in its 2013-2014 drilling campaign, wildcat well 7227/10-1, has come up dry. The well was located in the Saturn prospect, about 210km northeast of Hammerfest, in production license 230 in the Barents Sea, off Norway. It will be permanently plugged and abandoned. Drilling reached 3095m below the sea surface, at 232m water depth, using the *Transocean Spitsbergen* semi-submersible drilling rig.

K TGS, EMGS expand Barents coverage

TGS and Electromagnetic Geoservices (EMGS) agreed to further expand the companies' previous cooperation agreement in the Barents Sea. TGS will partner with EMGS to acquire electromagnetic (EM) data over approximately 10 new blocks in the Nordkapp and Tiddly areas.

The M/V *Atlantic Guardian* will acquire the new 3D EM data, which will be available to clients through both EMGS and TGS.

L Second Senegal target dry

Cairn Energy confirmed an oil find on the SNE-1 well offshore Senegal, but says a deeper target was dry. Oil was discovered in the upper clastic target, but no hydrocarbons were encountered in the deeper target Lower Cretaceous shelf carbonates.

The SNE-1 well was drilled using Transocean's semisubmersible drilling rig *Cajun Express* in 1100m water about 100km offshore in the Sangomar block. The well was drilled to 3000m TD.

M Statoil drops out of Kwanza

Statoil is paying US$350 million to take a "time-out" in its Kwanza exploration drilling program off Angola affer disappointing drilling results. The Norwegian giant canceled the *Stena Carron* rig contract after it fulfilled the work commitments in Blocks 38 and 39 back in November. Although Statoil says it still sees remaining prospectivity in the basin and the acreage, more time is needed to evaluate the well results and mature new prospects before deciding on future activities.

N Woodside ups Morocco stake

Woodside entered into a 12-month contract for an exclusive Reconnaissance License (RL) with the Office National des Hydrocarbures et des Mines, the national oil company of Morocco, to explore the Rabat Ultra Deep Offshore area. The block is just west of the Rabat Deep Offshore I-VI permits, and covers 36,737sq km in 1700m-4400m water depths.

Commitments under the RL work program include a 2D seismic survey and studies.

O Benthic in Mozambique survey

Anadarko Petroleum awarded Benthic a contract for a deepwater geotechnical investigation in the Golfinho field off Mozambique. Mobilization onto the *Jaya Vigilant* will begin in January 2015. Benthic's PROD (portable remotely operated drill) will perform rotary rock coring and piston coring in water depths up to 2500m.

P Masirah orders 3D seismic

Masirah Oil picked Dolphin Geophysical to conduct a new 3D seismic survey of Block 50, on the southeast coast of Oman, using the *Artemis Arctic* vessel.

Block 50 covers 16,903sq km, where non-commercial hydrocarbons were discovered at the MNN#1 well in 4Q 2013, followed by a second exploration well which discovered several formations with hydrocarbons in the beginning of 2014.

Q Eni targets offshore Turkmenistan

Italy's Eni and the Turkmen State Agency for Management and Use of Hydrocarbon Resources signed a memorandum for the possibility of extending Eni's current activities in Turkmenistan to the offshore sector in the Caspian Sea. Eni currently holds a 100% stake in the onshore Nebit Dag block, where the Burun oil field is currently in production.

R Rosneft confirms Kara Sea find

Russian authorities confirmed the reserves in the Pobeda oil and gas field, on the Kara Sea shelf. FSI RPE Rosgeolfond has been advised to register the field as having recoverable reserves of 130 million tons of oil and 499 Bcm of gas.

The gas reserves were discovered in the chalk deposits of Cenomanian Age and Apt-Alb Age., while oil reserves were discovered in Jurassic sediments.

The field was discovered through the Universitetskaya-1 well.

S Ophir signs Myanmar PSC

Ophir Energy signed a production sharing contract (PSC) with the Myanmar Ministry of Energy to finalize the award of Block AD-03, offshore Myanmar.

Located in the Rakhine basin, the 10,000sq km block is on trend with the multi-TCF, producing Shwe gas field. Ophir will reprocess existing 2D seismic data and will acquire 3D seismic data as part of the initial exploration period.

Ophir serve as operator with a 95% interest.

T CNOOC starts Panyu 34-1/35-1/35-2

CNOOC Ltd. began production at its Panyu 34-1/35-1/35-2 project in the South China Sea.

Panyu 34-1/35-1/35-2 is located in the Pearl River Mouth basin in a water depth range of 195-338m.

CNOOC's project consists of three gas fields: Panyu 34-1, Panyu 35-1 and Panyu 35-2. The main production facilities include one comprehensive platform, two sets of underwater production systems and 13 producing wells.

Currently, there are two wells producing approximately 21 MMcf/d of natural gas, with the project expecting to complete its overall development plan designed peak production of approximately 150 MMcf/d in 2015.

CNOOC holds 100% interest in the independent project, Panyu 34-1/35-1/35-2.

U Lundin bites dust on Kitabu-1

Lundin Petroleum's Kitabu-1 exploration well, in Blocks SB307/SB30, offshore Sabah, Malaysia, has come up dry.

The company spudded the well, located in 50m of water, on 27 October using Seadrill's West Prospero jackup rig, and reached 2270m. The well, one of 22, targeted the Miocene-aged turbidite sands, and will now be plugged and abandoned.

Lundin said the primary reservoir interval contained poor quality siltstone, and that no hydrocarbon shows were seen in the well.

V First oil from Maari field

Oil production has begun at OMV's US$255 million Maari redevelopment, located around 80km off the Taranaki coast of New Zealand.

The MR-8A well was sidetracked out of an abandoned injection well and drilled horizontally into the Moki formation to a total length of 3824m, resulting in production capacity at an estimated 4500 bo/d (gross).

The field, which is located in around 100m of water, was shut-in from July to December 2013 for remedial work and upgrades.

The completion of the redevelopment is expected to increase production to around 290,000 bo/d (gross). ■

Contract Briefs

Solstad gets Thai work

Solstad Offshore's derrick lay barge *Norce Endeavour* will be in use for Chevron's 2015 offshore campaign off Thailand.

Upon the terms of the contract, the *Norce Endeavour* will be utilized for 110-120 days to install 14 wellhead platforms, with preparation for mobilization starting mid-April 2015.

Solstad will provide project management, engineering, procurement and logistics to support the barge installation and construction scope of work through its derrick lay barge marine projects group in Singapore. Chevron has the option to hire the *Norce Endeavour* for its 2016 campaign.

Kara Sea JV cancels Siem Offshore contract

The ExxonMobil-Rosneft joint venture Karmorneftegaz SARL notified Norway's Siem Offshore that it has terminated Siem's contract for the 2015 season. The original contract stipulated that an early termination fee is payable. The charter contracts were originally announced in November 2013, and covered a "firm" five-month period during the summer season in 2014 and 2015, valued at approximately US$60 million, net of local taxes.

McDermott installs single point mooring tower off Indonesia

McDermott International has concluded the transportation and installation of a Yoke-type single point mooring tower and hook-up to a floating storage offloading vessel for PT Rekayasa Industri offshore Indonesia in the Banyu Urip field. McDermott used Derrick Barge 30 for the mooring tower installatioin and hookup to the FSO unit.

PT Rekayasa Industri was appointed by Mobil Cepu Ltd., an ExxonMobil subsidiary, as one of the EPCI contractors for the field. The Yoke-type single point mooring tower is a critical component that enables mooring of the FSO unit at the site.

Petrobras picks Modec-Schanin for FPSO

Petrobras awarded Modec and its Brazilian partner Schahin Group a contract to supply, charter, and operate a floating, production, storage, and offloading (FPSO) vessel for the Tartaruga Verde and Tartaruga Mestica fields offshore Brazil.

Scheduled for delivery in 3Q 2017, the FPSO will be capable of processing 150,000b/d of crude oil, 176 MMscf/d of gas, 200,000b/d of water injection and has the storage capacity of about 1.6 MMbbl of crude oil.

Upon the terms of the agreement, the Modec-Schahin consortium is responsible for the engineering, procurement, construction, mobilization, installation and operation of the FPSO, including topsides processing equipment as well as hull and marine systems. Modec's subsidiary, Sofec will design and supply the spread mooring system.

Proserv wins Hess subsea supply

Hess awarded Proserv a contract worth US$20 million for the provision of a 12-well subsea control system along with associated topside and subsea interface equipment for the deepwater Stampede development, in the Gulf of Mexico. The systems will be delivered to Hess in a phased approach throughout 2015 and 2016 in line with key project milestones. ■

New in 2015!

Libra's exploration challenges

The giant Libra field has many challenges, sitting in Brazil's deepwater pre-salt. Claudio Paschoa take a look at the development plans.

Field of View is a new monthly section that highlights an offshore oil and gas field, tracking its development, and the challenges and solutions involved.

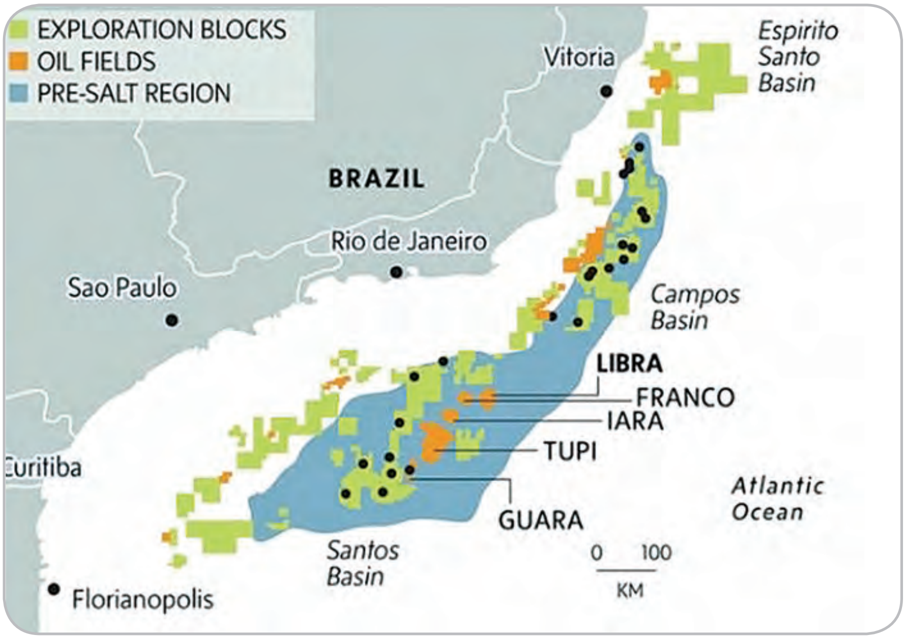
Petrobras, Brazil's national operator, is beginning its exploration of the massive Libra field in the ultra-deep Santos Basin with plans that include seismic reprocessing, two exploration wells and an extended well test.

The Libra pre-salt field, 183km (113mi) off Rio de Janeiro, has 8-12 billion bbl estimated reserves, but offers a number of technological and logistical challenges. Ultra-deepwater pre-salt developments are considered to be among the most challenging projects for the industry.

Drilling through up to 7km of rock and thick salt layers requires advanced technology, such as managed pressure drilling (MPD), to avoid wellbore creeping and deformation. There is therefore a demand for drillships with MPD capability, as well as a need for better seismic imaging under the salt, improved recovery methods, such as the water-alternating-gas (WAG) injection system, and for custom-built high-capacity FPSOs.

Libra encompasses 1548sq km (598sq mi). It was discovered through well 2-ANP-0002ARJS in 2010. A consortium, comprising Petrobras (40% interest) and partners Shell (20%), Total (20%), China National Offshore Oil Corp. (10%) and China National Petroleum Corp. (10%) won the license to develop the field in the October 2013 bidding round and agreed to pay a signing bonus of about US$7 billion.

Petrobras is the sole operator and the Brazilian government's share of the profit oil (oil produced after initial development costs are paid) is 41.65%. The Pré-Sal Petróleo S.A. (PPSA) was created as a government mechanism solely dedicated to manage and audit pre-salt field developments, beginning with the Libra field.



The Libra prospect and the pre-salt region. Image from Mercopress.

According to plans laid out during the Rio Oil & Gas 2014 conference by PPSA CEO Oswaldo A. Pedrosa Jr., the Libra development will use advanced seismic acquisition technology for a new seismic survey covering the entire area of the prospect. Existing 3D seismic data will be reprocessed to improve imaging in critical areas. The original seismic survey was done by CGG and they will be in charge of reprocessing and the new survey, which is already under way.

Two exploration wells were drilled in 2H 2014 and will be completed by 2015. These two wells are planned for the first phase of the Minimum Exploration Program (known by Portuguese acronym PEM) agreed with Brazil's National Oil, Natural Gas and Biofuels Agency (ANP). Petrobras is targeting three or more fully MPD capable ultra-deepwater rigs for Libra in an ongoing tender.

MPD was used successfully on wells at the Franco South, Lara and Lula North fields. The technology proved to be very efficient in the complicated deviated entrances to pre-salt reservoirs, making these difficult wells viable and reaching targeted depth, where other drilling technologies may have failed. MPD has also proven to be capable of increasing productivity, improving drilling safety and possibly even giving the operator new options for circulating gas kicks. Until recently, Weatherford was the sole manufacturer of the MPD system, although Aker Solutions is now also in the market after its 2013 acquisition of Managed Pressure Operations.

In October, Petrobras announced that the Libra Consortium had signed a letter of intent with Odebrecht/Teekay (OOG-Teekay), winner of a tender, for the charter of an FPSO designed for the extended well test campaign at the Libra field. The delivery of the FPSO and the start-up of the first extended well test are scheduled for 4Q 2016. The plan is to conduct tests in several distinct areas of the block, in order to evaluate the production performance and acquire additional data on the reservoirs.

Future production systems will be designed based on these data. For each test, two wells will be connected to the FPSO: one oil producer and one gas injector. The extended well tests will be the first in the world to carry out a gas re-injection system. The FPSO will have a 50,000 bo/d processing capacity and 141.25 MMcf/d (4 MMcu m/d) gas injection capacity. Most of the produced gas will be re-injected into the reservoir for pressure maintenance and a small part will be consumed during operations.

According to the original Libra production-sharing contract, the exploratory phase would run through December 2017. The extended well test, a key part of the approximately $450 million exploration development plan, is to begin in 2016, at the latest, as the partners in the Petrobras-led consortium are hoping to anticipate production start-up in 2017.


PPSA CEO Oswaldo Pedrosa Jr. Photo by Valter Campanato- Agência Brasil

"The idea is to do this as a fast-track phased development based on robust and flexible solutions," Pedrosa says. "We'll learn from the first phase. Libra is too big. It's impossible to do this kind of thing with just one unique project development. You have to do it in parts. We are going to learn a lot from each phase and find the best solutions for the next phase. We need to have solutions based on robustness and flexibility," Pedrosa says. Petrobras' ability to meet its fast-track development goals for the field will depend on several factors. "It depends on the availability of resources, particularly human resources. There are so many projects, and things are going so fast that there is a shortage of technical people to do the work, but this is something that can be solved," Pedrosa says.

Petrobras, along with the Brazilian government have been sponsoring a series of technical training programs in different areas and catering to different levels of expertise in order to solve this problem. However, further complicating matters is the tight oil and gas supply chain and service market in Brazil. Pedrosa says that the supply chain demand is predicted to reach an estimated $400 billion in the next decade. "It is very important to say that there is a challenge because we need to do fast-track development, and we need to comply with local content requirements," Pedrosa says.

"It is tight in Brazil and worldwide," he says, adding that this is something the consortium needs to think about and work on with others. To help overcome constraints in the supply and services market he suggested Brazilian and international suppliers form partnerships.

PPSA was created in 2013 with the main duties of managing the production-sharing agreement, representing the federal government's interest, managing unitization agreements and trading the share of profit oil on behalf of the federal government, Pedrosa says. The PPSA also ensures that the local content commitment is met. As chair on the operating committee, PPSA also has veto power.

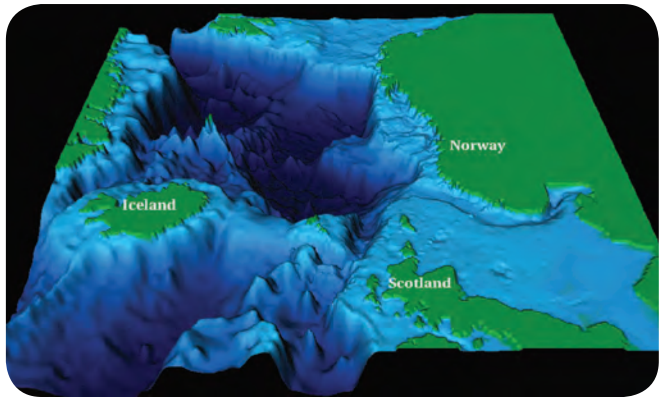
According to Pedrosa, "PPSA's job is to manage and audit the project execution for exploration, appraisal, development and production; monitor and audit the operating costs and capex; manage the recognition of qualified expenditures; [and] perform technical and economical analysis of plans and programs to be executed in each production-sharing agreement."

Focusing on the Libra contract and managing production unitization agreements, Pedrosa said that, "Everything is going alright at this stage and we are excited to start drilling the new exploration wells." OE

Current complexities

The weather conditions west of Shetland are some of the harshest in the world, even without the help of hurricanes, typhoons and squalls. Elaine Maslin reports on how some companies are attempting to better understand the region.

The predominant current patterns, showing the Faroe-Shetland Channel.
Image from Woods Hole Oceanographic Institution.



A 3D visualization of the channel and surrounding area, by the Department of Mathematics, University of Oslo.
Image from Island Offshore.

In a presentation about conditions west of Shetland last year, the presenter said the following: "Considerations on Wheatstone (Australia) were cyclones. The Gulf of Mexico is concerned with hurricanes. Indonesia is concerned with typhoons. Scotland doesn't have typhoons, hurricanes or cyclones. We just have weather."

The comment is something of wry understatement, particularly as the talk was about the conditions west of Shetland, which, on a good day, are daunting for most. The area is remote and battered by wind and significant wave height.

But, what happens beneath the waves west of Shetland is just as big a challenge, if not greater, and less understood. Ocean currents west of Shetland are driven by the exchange of water between the North Atlantic and the Nordic Seas. According to Fugro GEOS, Fugro's metocean subsidiary, currents in the area carry about half the total warm water flowing northward in to the Arctic Ocean and about one third of all the cold water flowing out of it.

The current regimes are also extremely complex, and, creating one of the biggest issues facing those wanting to understand what is happening west of Shetland, is that there is a paucity of data, which makes modeling difficult.

Experiencing the conditions for the first time can be a steep learning curve. Speaking at a well intervention seminar in Aberdeen in 2014, Tor Erik Grønlie Olsen, operations manager, at Norway-based Island Offshore, described the firm's second experience in the area, using the *Island Constructor* on BP's Loyal field in 2010, as "horrible" and "difficult," despite extensive experience working north of the Arctic circle. For Olsen, the sea state is not so much of a problem. "West of Shetland, weather-wise, could be a 365-day area. It is the sea currents under the water that is the show stopper," he says.

The Foinaven FPSO.
Photo from Teekay Corporation.

The main issues were multiple, multi-directional ocean currents, creating a horizontal force of up to 4-tonne, on umbilicals, for at least 25min/d—on a good day—acting as saw on parts of the vessel. "There are several current scenarios which can, at the worst times, meet up all at once. There are several layers of currents and they are flowing in different directions. It is a really challenging area," Olsen says.

John Mitchell, metocean advisor at the UK's Met Office specialist marine center for offshore energy, based in Aberdeen says: "The sea state is pretty well understood and predicted. There is also a broad understanding about ocean currents that impact the west of Shetlands. The challenge is to utilize this knowledge of these broader scale features to drive more detailed predictions of currents of suitable quality to help the offshore industry as it works close to the edge of the Continental Shelf."

The main oceanographic feature west of Shetland is the Faroe–Shetland Channel, a gorge-like feature, heading south-west to north-east, between the Faroe Isles and Shetland. It is about 1000m deep at its shallowest, reaching more than 1500m deep, and about 200mi wide, with its slopes being less steep on the west side, where it forms the Faroese Shelf, says John Siddorn, head of the Ocean Forecasting Research and Development group and co-chair of the National Centre for Ocean Forecasting (NCOF). Although it is one of a number of deepenings on the Scotland-Greenland Ridge, it is a key feature for understanding ocean current in the area, Siddorn says.

"It acts as a channel for the cold water flows coming out of the Nordic Seas going south, and (warmer) Gulf Stream/North Atlantic flows going over the top of those to the north, along the Shetland shelf edge (a thermohaline driven overturning of water between the North Atlantic and Nordic seas)," he says. "The top 300m

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	2011	2012	2013	2014
Shallow (<500m)	105	75	72	55
Deep (500-1500m)	25	23	19	231
Ultradeep (>1500m)	18	37	34	12
Total	148	135	125	90
Start of 2014 date comparison	151 - 3	135 -	98 27	- 90

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 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	13	604.25	4,803.28
Deep	17	1,801.00	2,935.00
Ultradeep	53	16,389.75	20,593.00
United States			
Shallow	15	101.5	224.00
Deep	18	1,219.27	1,580.48
Ultradeep	27	3,970.50	3,280.00
West Africa			
Shallow	185	5,135.22	24,654.05
Deep	48	6,236.50	8,330.00
Ultradeep	24	3,239.00	3,790.00
Total (last month)	368 (368)	34,483.13 (34,483.13)	58,526.62 (58,526.62)

Greenfield reserves
2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow (last month)	1262 (1172)	46,441.71 45,163.57)	611,768.39 (738,895.77)
Deep (last month)	175 (152)	11,999.24 (12,228.98)	120,883.91 (71,319.00)
Ultradeep (last month)	122 (101)	24,016.65 (19,465.15)	73,260.00 (55,470.00)
Total	1,559	82,457.60	805,912.30

Pipelines
(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,594	(41,131)
Planned/ possible	24,193	(24,683)
	65,787	(65,814)
8-16in.		
Operational/ installed	81,651	(79,879)
Planned/ possible	49,002	(50,448)
	130,653	(130,327)
>16in.		
Operational/ installed	92,607	(91,827)
Planned/ possible	38,461	(48,024)
	131,068	(139,851)

Production systems worldwide
(operational and 2014 onwards)

Floaters		(last month)
Operational	285	(282)
Under development	41	(44)
Planned/possible	347	(351)
	673	(677)
Fixed platforms		
Operational	9302	(9,258)
Under development	117	(134)
Planned/possible	1407	(1,431)
	10,826	(10,823)
Subsea wells		
Operational	4783	(4,626)
Under development	271	(357)
Planned/possible	6631	(6,698)
	11,685	(11,681)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow (last month)	23,592.47 (23,581.06)	30,131.54 (31,310.29)	35,266.01 (42,264.94)	30,371.83 (28,922.33)	25,682.50 (45,956.92)	27,710.65 (27,179.23)	35,336.22 -
Deep (last month)	484.30 (484.30)	4,152.32 (3,952.06)	5,046.76 (5,247.02)	3,792.06 (3,882.06)	4,745.97 (4,944.12)	6,875.41 (6,768.69)	12,891.37 -
Ultradeep (last month)	2928.44 (2,932.94)	2,749.62 (2,749.62)	1,869.95 (1,869.95)	4,470.91 (4,470.91)	9,484.60 (13,584.66)	10,507.34 (6,569.81)	10,600.13 -
Total	27,005.21	37,033.48	42,182.72	38,634.80	39,913.07	45,093.40	58,827.72

11 December 2014

Three guidewires in 1.24 knot currents during a deployment phase. Photo from Island Offshore.

Damage from one of the guidewires to the lower cursor frame (LCF). The LCF sits in the moonpool area and acts as a guide/protection while deploying equipment through the moonpool and splash zone. Photo from Island Offshore.

goes along the east side of the slope going north. There is also water coming from Greenland and Iceland coming down towards the channel."

At 450m-500m below the surface, there is a strong permanent thermocline, marking the boundary between the warm (4°C-15°C) near surface current systems and the cold (-1°-2°C) waters of the south-westward flowing Norwegian Bottom Current, according to Fugro GEOS. This can create an interface on which internal tides have been observed, generating currents up to 0.5m/s, and something breaking down into smaller, non-linear internal waves where it meets the slope.

The large-scale current systems lead to a frontal system, separating the warm and cooler waters, and creating instabilities leading to eddies, deflections, meanders and filament-like jets and squirts, creating strong currents up to 0.7m/s, particularly in the upper part of the water column.

There are also intermediate waters adding to the mix and the area is also very close to the UK Continental Shelf, which is very tidal, creating further interactions. "It is a complex mix of different currents. Where they come together, there is a lot of interaction, including with the sea bed, and all sorts of processes, which make it quite difficult to understand and model," Siddorn says. "A lot of work needs to be done for us get enough information to fully understand this area."

For operators, the area is poorly observed and the data that exists isn't available in an easily digestible format for planning subsea operations. The complexities make the area inconsistent.

Exploration in the area started in the 1970s, but it wasn't until 1992 that the first commercial discovery was made, with Foinaven, 190km west of Shetland, in 350-520m water depth, followed by Schiehallion (now part of the Quad 204 project, a redevelopment of the Schiehallion and Loyal fields), 130km west of Shetland, in 350-500m water depth, both of which have been developed using FPSOs.

All are on the eastern upper slope of the channel. Here, according to a July 2010 presentation by the LWI Alliance, including Island Offshore, "the slope current dominates, so that net flow is usually towards northeast, following depth contours."

The current speed is around 0.3m/s, with tides usually recognizable as modulations about the mean, and seldom reversing the flow. However, eddies can increase the current to up to 1-1.5m/s, usually in the same northeastward direction, but, it says, all directions are possible.


Island Offshore's *Island Constructor.* Photo by Ronnie Robertson.

Deeper than 350m, there is a risk of sudden severe currents close to the seabed, associated with internal waves. In deeper waters (500-1000m+), the lower slope's influence on the current is less strong, which means flow direction can be more variable and eddies can strengthen currents in any direction.

Darren Chalmers, senior operations engineer at Island Offshore, said most of the challenges while working west of Shetland had been in the Schiehallion and Loyal fields, relating to current strength, With the current tending to maintain a consistent direction throughout the water column, however, changes to direction could occur at random depths and for random durations.

Fugro GEOS says the slope current and tidal current on the eastern slope of the channel reinforce each other for one half of the 12-hour tidal cycle and oppose each other for the other half, with the upper water column maintaining a north-easterly direction. In the lower part of the water column, tidal currents can also be overcome so that the current maintains its south-westerly direction throughout the tidal cycle. A strong current could move the end of an umbilical 2-300m from where it needs to be, as well as causing damage to vessels, Chalmers says.

There is a NERC project, called FASTNEt (Fluxes across sloping topography of the northeast Atlantic), which is looking to better understand the interaction between the ocean and the wider UK shelf seas, using gliders, or AUVs, to help gather data.

This would also help companies manage another potential problem, in addition to installation, maintenance, intervention, and decommissioning activities – oil spills. In normal environments, spills would be expected to disperse vertically and horizontally with the current. But, because of the strong density gradients acting as barriers to movements in the water column west of Shetland, this does not necessarily apply. "It would be quite complex to think where any spills might end up," Siddorn says.

Island Offshore has had campaigns every year west of Shetland since 2009. It has dealt with the situation by quickly learning about the conditions, Olsen says. For the first few years, it used two acoustic doppler current profiler systems, one on the ROV cage and a second hanging off the vessel, to carry out mapping and gain knowledge in the area. The firm also modified its vessels to cope with the demanding environment, including a permanent mud cap system (for well intervention operations), modifications to the hull, tower, handling equipment and additional protection to running equipment, as well as improving operational procedures and training and preparing animations showing equipment and pumping hose behavior in exposed ocean currents to prepare staff. These modifications have also helped extend the operational season, Olsen says.

"All the time we are increasing our knowledge, to see how we can operate for longer. Finding useful information about the current situation outside the current situation we are working in is very difficult because no one is operating there," Olsen says. "That's a fact, and we are determined to find more information." OE

Analysis

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	111	98	13	88%
Jackup	426	370	56	86%
Semisub	183	161	22	87%
Tenders	34	22	12	64%
Total	754	651	103	86%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	33	31	2	93%
Jackup	90	73	17	81%
Semisub	28	25	3	89%
Tenders	N/A	N/A	N/A	N/A
Total	151	129	22	85%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	15	11	4	73%
Jackup	117	103	14	88%
Semisub	38	27	11	71%
Tenders	25	14	11	56%
Total	195	155	40	79%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	27	27	0	100%
Jackup	9	6	3	66%
Semisub	36	35	1	97%
Tenders	2	2	0	100%
Total	74	70	4	94%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	51	49	2	96%
Semisub	46	44	2	95%
Tenders	N/A	N/A	N/A	N/A
Total	98	94	4	95%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	108	95	13	87%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	112	99	13	88%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	27	25	2	92%
Jackup	26	23	3	88%
Semisub	17	16	1	94%
Tenders	7	6	1	85%
Total	77	70	7	90%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	7	3	4	42%
Jackup	25	21	4	84%
Semisub	17	12	5	70%
Tenders	N/A	N/A	N/A	N/A
Total	49	36	13	73%

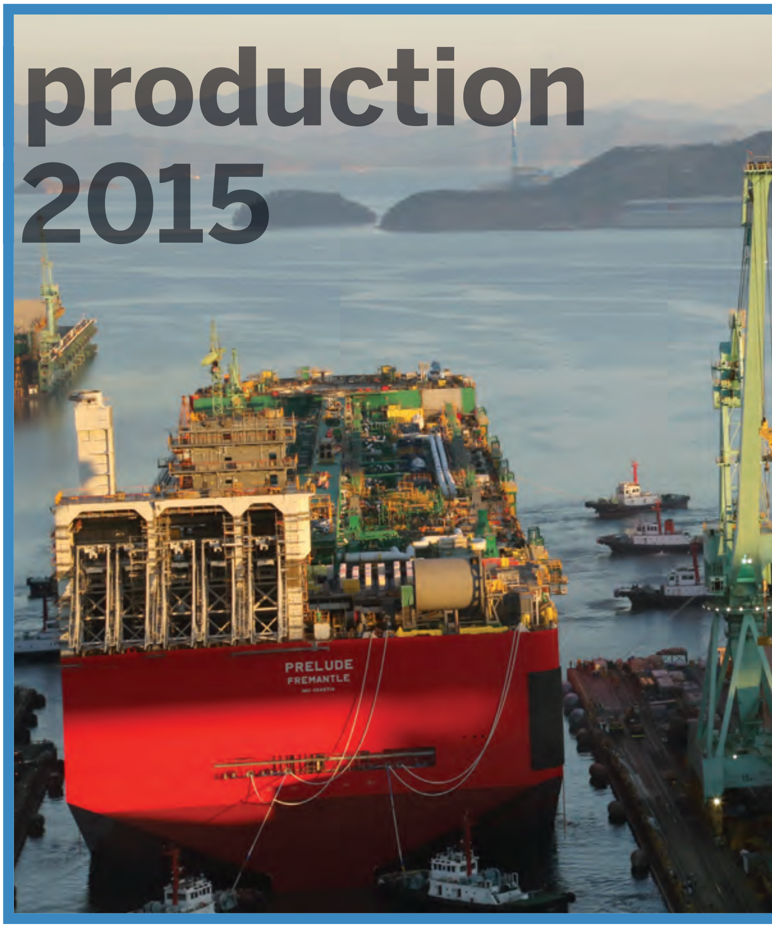
Source: InfieldRigs

16 December 2014

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

The floating production outlook for 2015

Infield Systems' Catarina Podevyn provides analysis on floating production projects around the globe and the impact they will have on individual regions this year.



Shell floats the hull of the *Prelude* FLNG vessel into place in Geoje, South Korea in November 2013. Teams shifted over 100,000t of steel during the operation. Photo from Shell.

The floating platform sector has undergone steady growth over the last five years. However, while a number of key projects are anticipated to generate substantial Capex demand over 2015, with low oil prices and uncertainty across some regions, Infield Systems remains cautious regarding the progress of some of the more capital intensive deepwater developments over the forthcoming year. Infield Systems' Floating Production Systems Market Report provides detailed analysis of this important sector over the period 2009-2018.

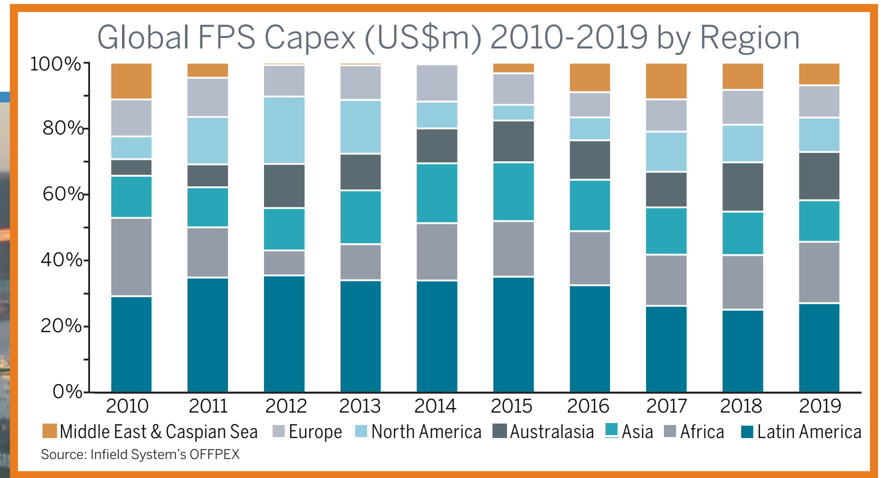
Latin America – Offshore Latin America, Brazil accounts 90% of regional demand; while the region as a whole is anticipated to drive global floating production system (FPS) demand with a 35% market share during 2015. Infield Systems forecasts Latin America's leading share to decrease to 25% decrease over the period, with a low of 25% in 2018. This is the result of a number of capital intensive developments seeing completion during 2014, including Sapinhoa North and Iracema Sul.

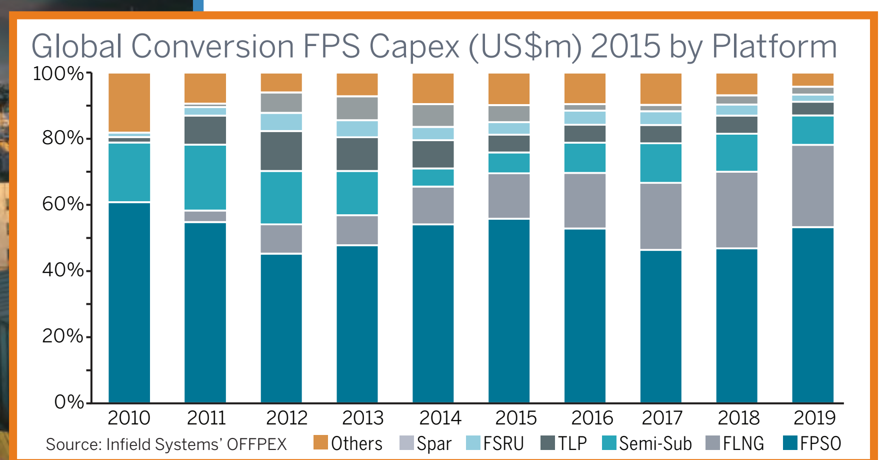
During 2015, Infield Systems expects capital expenditure to be predominantly directed towards FPSO developments offshore Brazil, which are likely to comprise 84% of regional demand during the year. Key projects attracting investment during the year offshore Brazil include: Buzios, Lula Central and Lula West. Infield Systems also expects expenditure on the *Ayatsil-Tekel* FPSO to take place offshore Mexico. Over the longer term, with the Mexican energy reforms finally coming to fruition, the prospectivity of Mexico's deepwater fields is also expected to increase. 2015 is also likely to see continued investment on Colombia's FLNG project, Caribbean FLNG, developed by Exmar and the new Cartagena FSRU.

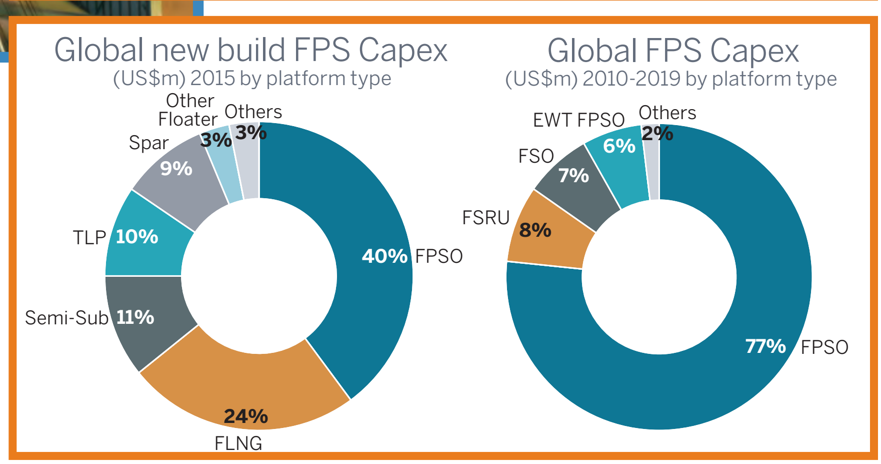
Australasia – Asia is forecast to hold the second largest share (18%) of global FPS expenditure during 2015. This is expected to be largely driven by FLNG developments, with projects including the Petronas *PFLNG 1* and *PFLNG 2* FPSO facilities and the *Abadi FLNG* FPSO all anticipated to require substantial investment during the year. Indeed, across the region Infield Systems expects FLNG projects to comprise 31% of total 2015 FPS expenditure. Driven by its capital intensive FLNG projects, Malaysia is expected to drive expenditure with a 37% share of regional FPS demand, followed by Indonesia with a 31% share during the year.

Australasia is expected to contribute a 13% share of global FPS Capex demand during 2015, with a total of six developments anticipated to require investment during the year. Once again FLNG FPSO projects are expected to comprise a substantial share of demand, with the Shell operated Prelude FLNG forecast to require the highest Capex during the year. Inpex's *Ichthys* semisubmersible development, anticipated to be installed during the course of 2016, is expected to be the second most capital intensive development taking place in the region during 2015, after Prelude, at a water depth of 230m, the development also includes an FPSO installation and is expected to bring a total of 8.4 MTPA of gas to the market. Infield Systems also expects possible Capex spend to take place on the Cash/Maple FLNG FPSO and the Brecknock FLNG FPSO during 2015

Africa – Angola is expected to continue to lead FPS development throughout 2015, with a 43% share of regional Capex demand. Key projects expected to demand significant expenditure during the year include the *Kaombo North* FPSO and the *Cameia* FPSO, which are operated by Total and Cobalt, respectively. However, with the recent drop in oil prices, deepwater developments such as these are now coming under review, with Maersk rethinking its stake in Chissonga in particular. Elsewhere within the region, Infield Systems also expects significant expenditure to take place on the Total-operated *Egina* FPSO and the Moho Nord tension leg wellhead platform projects, offshore Nigeria and Congo (Brazzaville),







respectively. Indeed, Infield Systems expects the French IOC to increase its dominant share of regional floating platform Capex demand from 47% over 2014 to 53% over 2015.

Europe – Europe is expected to account for 9% of global FPS Capex demand during 2015, with Norway likely to account for a 68% regional market share. Statoil's Aasta Hansteen Spar is anticipated to drive investment demand during the year, with a 47% share of regional FPS spend. Infield Systems also forecasts Capex demand on a further 16 projects across the region including seven FPSO developments; the highest Capex demand of which is expected to relate to the BP Glen Lyon Quad 204 FPSO and the Enquest-operated Kraken and Eni's Goliat *Sevan 1000* FPSO, the latter of which is anticipated to see completion during the year.

North America – North America is forecast to contribute a 5% share of global floating platform Capex during 2015. Semi-submersible projects are anticipated to require the highest demand. However, with the decrease in oil price, capital intensive projects, such as the Buckskin/Moccasin semi-submersible development, operated by Chevron, are likely to see delays. Infield Systems also expects substantial FPSO investment on developments including Shell's *Stones* FPSO in Walker Ridge and the Kitimat FLNG offshore British Colombia. However, once again the project faces challenges; although progressing well, with the news that partner Apache is looking to sell its 50% stake in the project, finding a partner for the development may prove difficult in the current climate.

Middle East – And lastly, the Middle East and Caspian region is expected to form 3% of global FPS expenditure demand during 2015. While remaining a marginal region in terms of FPS development, with activities in the Levant Basin increasing, Infield Systems expects expenditure to rise over the medium term. During 2015, Noble's Tamar FLNG FPSO (King Project) offshore Israel is anticipated to demand the highest Capex, followed by the operator's Leviathan FPSO development, which could see completion before the close of 2018. Elsewhere in the region during 2015, Infield Systems expects FPS Capex to be required offshore Kazakhstan for barge units, Iran and Jordan for possible FPSO and FSRU units. OE

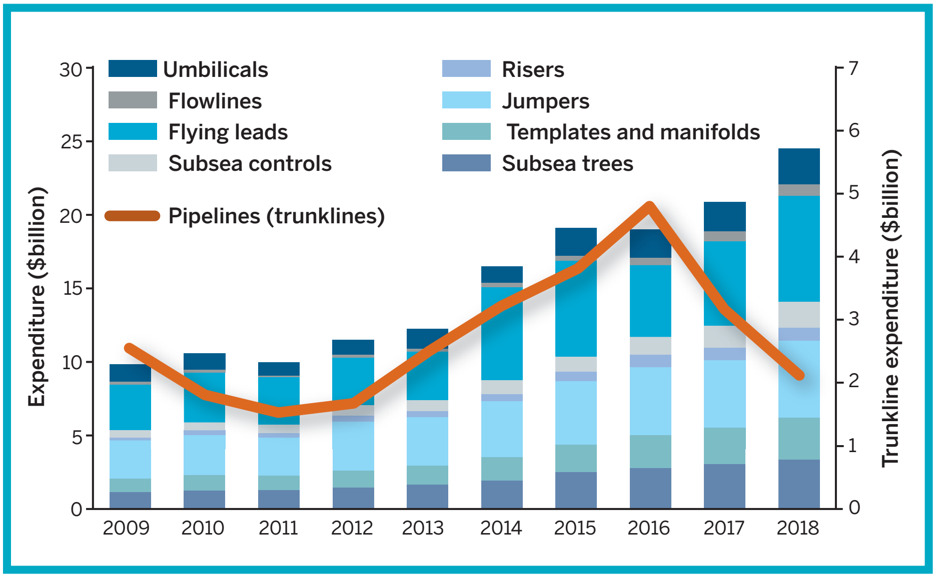
Subsea infrastructure - growing and moving deeper

Subsea hardware spending in 2014-18 is forecast to nearly double the size of installed subsea infrastructure, according to Douglas Westwood's latest estimates. Matt Loffman sets out the detail.

Douglas-Westwood forecasts subsea hardware capex will total US$117 billion between 2014 and 2018, representing growth of more than 80% compared with the preceding five-year period.

Subsea production hardware is expected to attract $57 billion of expenditure, as high-value projects come onstream. The subsea umbilical, riser and flowline market approaches $43 billion while pipeline spend is forecast at $17 billion.

Global subsea hardware Capex by equipment type



Source: Douglas-Westwood: World ROV Operations Market Forecast 2013-2017.

This vast expenditure will nearly double the size of the existing infrastructure network, below the water surface. With non-productive time and delays prohibitively costly for operators, the outlook for high quality subsea inspection, repair and maintenance (IRM) is positive.

Growth in subsea infrastructure spend continues trending towards deeper waters. Around 44% of total Capex in the next five years will be targeting projects in >1000m water depth. A large portion of prominent offshore projects and the vast majority of the so-called mega-projects, with greater than $10 billion Capex, are in deepwater areas.

In addition to the established deepwater regions in Brazil, West Africa and the US Gulf of Mexico, the newly discovered offshore gas provinces in East Africa and the Eastern Mediterranean are also in >1000m water depth and are expected to provide additional markets, which will positively impact IRM expenditure in the future.

Utilization of ROVs and AUVs to trend upwards in IRM

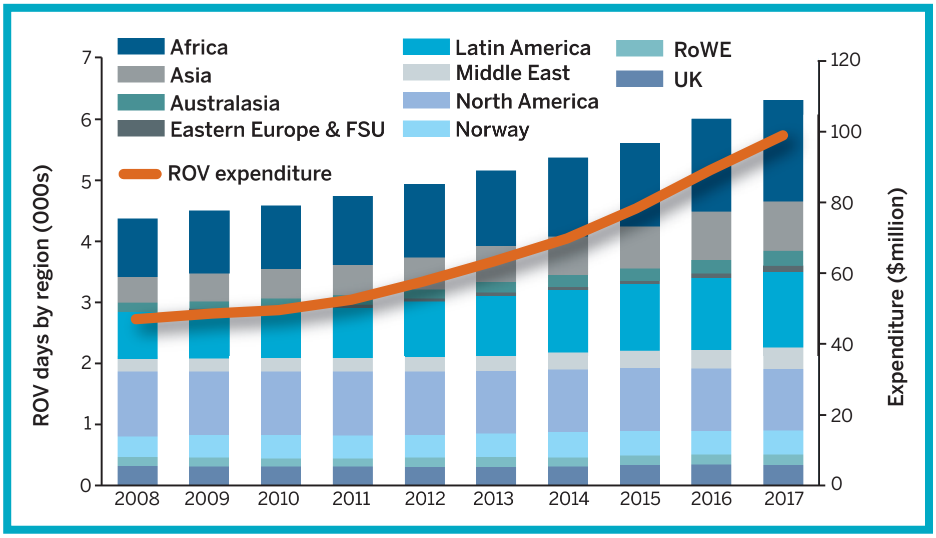
A large proportion of subsea IRM work is executed by remotely operated vehicles (ROVs). IRM support typically entails work-class ROV inspection, replacement tasks, cutting operations, hatch operations on subsea structures and valves, as well as cleaning tasks.

Although IRM is the smallest market for work-class ROVs, its Opex driven nature ensures that it is one of the most secure in terms of vulnerability to oil price volatility. Driven by the ever-increasing volume of installed subsea hardware described above, demand for IRM is forecast to rise from 5180 days in 2013 to 6338 days in 2017, at 5.2% compound annual growth rate. Associated expenditure is forecast to increase from $63 million to $99 million and the number of dedicated work-class ROVs required from 20 to 25.

Another sector where subsea IRM growth shows promise, relates to autonomous underwater vehicle (AUV) operation. Increasingly used for deepwater surveys, at present a range of technological advancements in the space are being developed. AUVs are commercially proven in pipeline inspection markets, while developments in other areas are taking place at present.

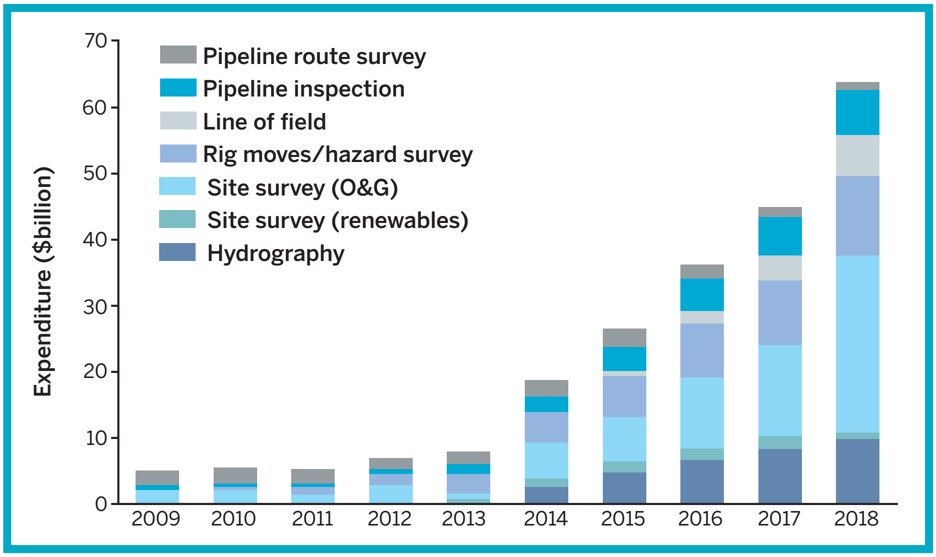
Life-of-field inspection work and sealine inspection surveys are similarly in the early stages of commercial development. Tests employing AUVs for sealine inspections have been carried out recently and are continuing to be applied to the units in some regions, while life-of-field inspection activity has generally been delayed until 2015. With the growing infrastructure and subsea pipeline network, we expect to see AUVs gain market share over the coming five-year period.

Figure 2: Global ROV demand by region



Source: Douglas-Westwood: World ROV Operations Market Forecast 2013-2017.

Figure 3: AUV unit demand by commercial function.



Source: Douglas-Westwood: World Subsea Hardware Market Forecast 2014-2018

Capex cut-backs threaten near-term growth rate of subsea infrastructure

Reductions announced by many of the major international operators in 2014 are expected to threaten projects with higher capital outlay, including those in deepwater and conditions otherwise suitable for subsea field development. Some uncertainty in crude oil prices may also expose projects with higher break even prices, although this is generally expected to be limited to the short-term.

Reductions are expected to slow growth in upstream Capex in the short-term, extending to 2015. However, subsea IRM retains a positive outlook, servicing an expanding network of subsea infrastructure – albeit expanding at a lower pace in the near-term than would have been the case otherwise.

However, as the present situation in the Middle East proves, there is always potential for oil prices to again rise and further drive the move into deepwaters and with further growth in the associated capital expenditure.

Subsea IRM has a positive outlook

Subsea developments will continue to account for an ever-increasing share of global offshore activity. The technologies deployed are unlocking reserves that would previously have been difficult or impossible to access and the sector has become a sizable opportunity for the oilfield service and equipment industry. The outlook for the subsea IRM market shows growth potential well beyond a five-year forecast, particularly in the longer-term as Arctic resources are targeted off Canada, Norway and Russia. This is positive news for IRM providers who continue to gain importance in the global industry. **OE**

Matt Loffman*, since joining Douglas-Westwood, has worked on a range of research and advisory projects focusing on international drilling and oilfield service provision and downstream markets. He specializes in analysis of frontier markets and the Middle East. Loffman is a graduate of the London School of Economics and the University of Damascus and lived for a number of years in the Levant.*

GlobalData's Adrian Lara sheds light on the kinds of deepwater projects expected to advance while the price of oil continues to fall.

Different risk profiles among deepwater projects

Engineers from Jumbo Maritime deliver 25 MOF caissons for the Chevron-operated Gorgon development offshore Western Australia, in 2012. Photo from Jumbo Maritime.

With oil prices falling below US$70/bbl, sanctioning certain planned offshore developments for development becomes challenged. Capital investment for offshore assets will, however, continue and it is mainly a matter of delays to startup for most projects. Large recoverable reserves coupled with high-productivity wells allows for a large return on investment. While deep and ultra-deep water projects usually have higher development costs, drops in the oil price are also accompanied by reductions in the cost of services, supporting ongoing development.

The commercial risk associated with offshore projects varies depending on the stage of development; a key consideration is whether the project is planned, already under development or producing. GlobalData identifies at least three types of projects when assessing the impact of a permanent low price level:

1. projects that have recently started production
2. planned projects scheduled to start producing during 2015-2016
3. planned projects scheduled to start producing during 2016-2018

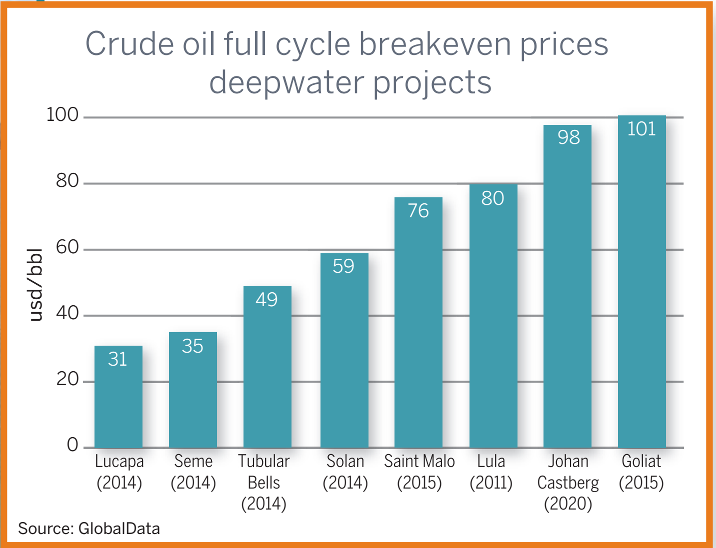
The first group of projects has already started production and has the lowest risk because costs are generally limited to ongoing operational expenditures, which are significantly lower. The second and third types of projects have already invested in exploration, appraisal and development, but have not started production. Normally, the ones scheduled to produce in the latest period, 2016-2018, would face the highest risk. Projects that have seen most of the capital expenditure already deployed, generally those in between 2015-2016, will be more costly to halt than to move forward.

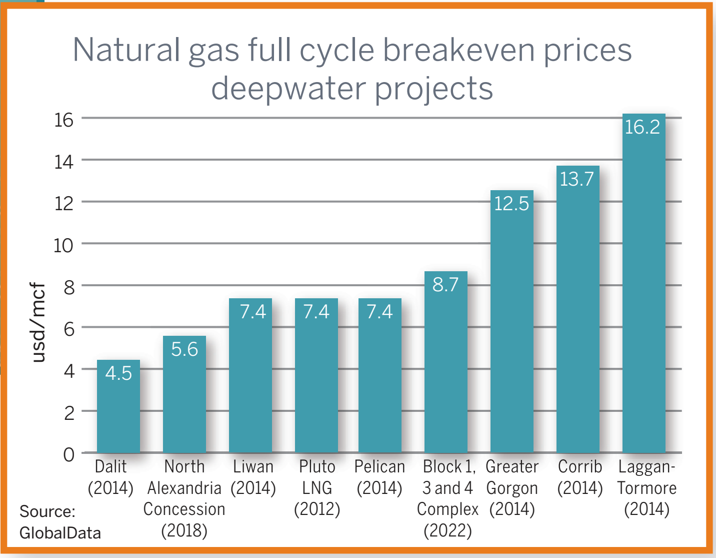
Project economics and total capital expenditure is impacted by many factors, including the type of production unit used, drilling and completion times, the development stage and the size of the resource. In the current environment of falling oil prices, service costs will also fall, reducing required capital, but in many cases, not enough to support the commercial viability of projects.

A change in the investment plans of oil and gas companies, due to a lower 2015 average oil price, will see spending limited to projects already under development and planned projects with relatively low break-even prices. Projects that have already contracted construction of producing facilities will most likely continue development, although with some degree of deceleration possible.

In the Gulf of Mexico, there was a revival in pushing forward projects since the *Deepwater Horizon* oil spill. Recently, a key partnership formed by Chevron, Statoil, Nexen and Hess announced the approval of US$6 billion in support of the Stampede development. Major offshore basins, the Gulf of Mexico, Brazil, and West Africa will all follow a similar logic in continuing their necessary capital expenditure in the operation of producing or already under-development projects.

Natural gas deep and ultra-deepwater projects are traditionally more challenging than crude oil projects, due to the





restrictions in transportation that reduces the options for export markets and makes them dependent on gas domestic prices. LNG projects, such as Greater Gorgon in Australia, have a clear advantage in reaching high gas price markets in Asia, countering the negative impact from the fall in the oil price, but increased competition and potential for a lower gas price looms.

Historically, deep and ultra-deepwater projects have experienced cycles in the rise and fall of oil prices. Their development requires a long-term view and, as argued before, pricing fluctuation is generally dealt with through delays, with operators turning to managing producing and already under-development projects. Deepwater operators tend to be well-established and financially sound companies with well-diversified portfolios of upstream assets mitigating risk. Whenever possible, they actively try to redirect their investment strategy towards assets that can provide the highest amount of cash flow. In this context, production assets are given priority over exploration assets that have a less certain flow of associated revenues. It is possible that some new deepwater exploration areas, such as the ones on the Mexican side of the Gulf of Mexico, will face a slowdown in the pace of their exploration and development, or worse, they might not gain the interest of major oil and gas companies if the bidding terms are not attractive enough. **OE**

Adrian Lara *directs GlobalData's upstream team in charge of conducting quantitative and qualitative research relating to oil and gas activities in Latin American countries. Lara has several years of experience as an oil and gas industry analyst, having held different positions within the trading arm of Mexican state-owned company Pemex, where he focused on analysis of oil and gas fundamentals in the context of upstream exporting strategies and international trading. Lara was also a visiting research fellow at the Oxford Institute for Energy Studies where his research focused on oil supply scenarios in the Western Hemisphere. Lara has a MS in mineral and energy economics from the Colorado School of Mines, with a specialization in oil and gas from the Institut Français du Pétrole. He has a BA in economics and political science from the Instituto Tecnológico Autónomo de México (ITAM).*

Supporting seismic in the Gulf of Mexico

With well data often scarce, many deep water Gulf of Mexico operators rely on the structural images and elastic properties derived from seismic when evaluating the probability of success and estimating reserves in prospective fields. Vincent Vieugue suggests this is not enough.

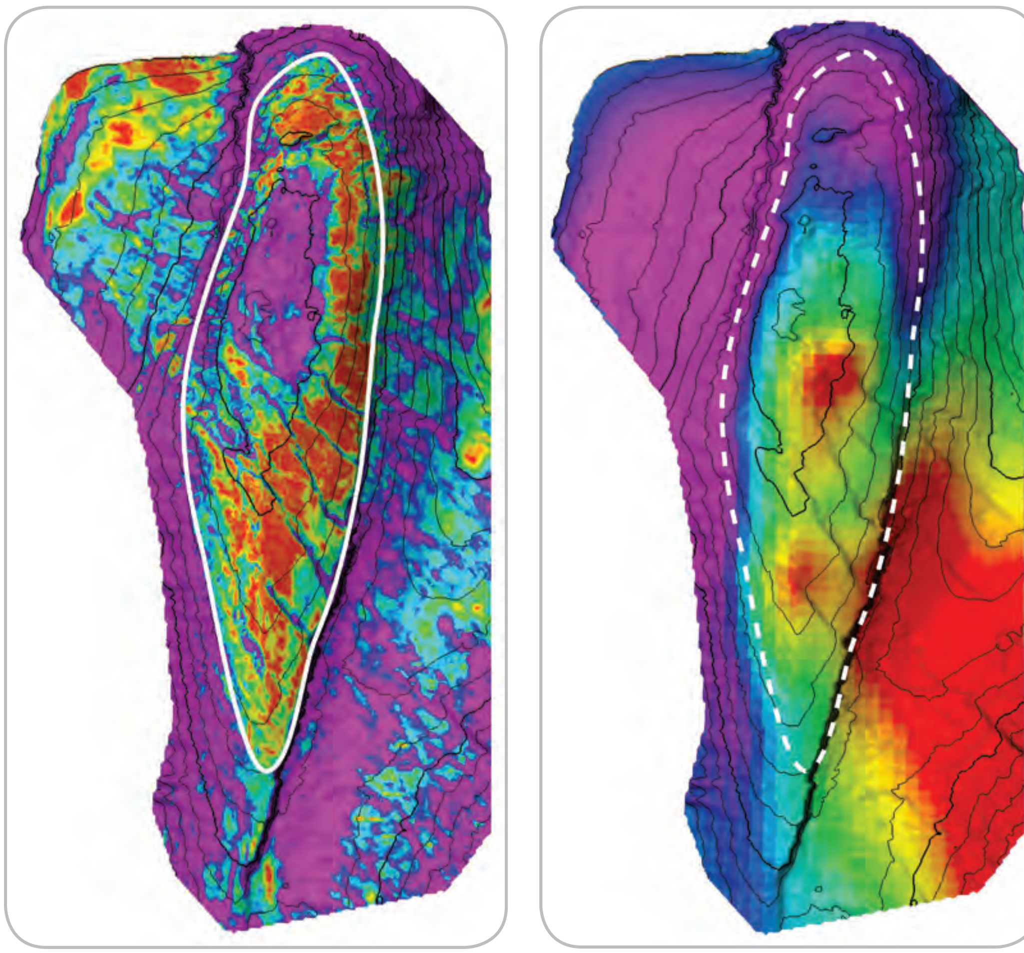


Fig. 1: Regional reservoir interval and the initial interpretation that relied purely on seismic data and geological knowledge, compared with an updated transverse resistance (TR) map that incorporates the CSEM data. Images from EMGS.

Seismic remains highly effective in generating structural and stratigraphic information as well as volume estimation parameters, such as gross rock volumes. While there have also been significant advances in areas such as amplitude versus offset (AVO) and seismic inversion, information gaps still remain when it comes to fluid content and the estimation of hydrocarbon volumes.

Questions still remain as to whether AVO responses are caused by fluid or lithological variations with a potentially negative impact on well placement and there are also issues around seismic's ability to interpret salt body geometries and create clear sub-salt images.

While seismic and reverse time migration (RTM) tend to provide a good definition of top-salt interfaces, where there is a high seismic impedance contrast, a partial definition is often the best operators can hope for when it comes to salt flanks and the base of salt and sub-salt. Distorted seismic wave fields, scattering, irregular illumination, complex velocity distribution and incomplete velocity models are often the norm.

Seismic needs support if it is to provide a complete picture of the subsurface and to avoid scenarios where prospects are identified as having strong seismic, AVO and geological potential, but are later found to be lacking in fluid content. One source of such support is 3D controlled source electromagnetic (CSEM).

3D CSEM, when integrated with seismic data, can lower exploration costs and increase discovery rates in the US and Mexican Gulf of Mexico (GOM).

3D CSEM surveys

3D CSEM data maps resistive anomalies in the subsurface, where the larger the resistive body, the greater the response. This is due to the electrical resistivity of the subsurface being a physical property that strongly correlates with the fluid content and saturation of hydrocarbon reservoirs.

Such EM methods are also well-suited

for imaging sub-salt sediment structures, where an intelligent well-constrained attribute correlation between inverted resistivity and compressional velocity in sediments can be used to refine the seismic velocity model and produce better seismic imaging for basement structures.

In addition, EM measures different rock properties to seismic and is subsequently unperturbed by the scatter and refraction that causes seismic such difficulties, accurately picking out the base of the salt in depth by the change of resistance and then applying this to the velocity model.

Whether in sub-salt fields or fields with other geological characteristics, integrating EM data into the exploration workflow to support seismic allows for a better classification of prospects through the downgrading or upgrading of the probability of finding hydrocarbons and an improvement in the evaluation of the size of the accumulation.

3D CSEM in the Gulf of Mexico

EMGS has a long history of conducting CSEM surveys in the GOM.

Since 2010, EMGS has acquired over 16,000sq km of 3D CSEM in the Mexican GOM for Mexican operator Pemex over >40 identified prospects.

In one example for Pemex, the prospect was located approximately 1800m below mudline and consisted of an anticlinal structure situated within a compressional belt, where a variety of compressional structures occurred at various scales. Overlying the main structure, a seismic sequence was present that was almost devoid of faults, providing just enough sealing capacity for the entire structural closure.

Figure 1 illustrates the regional reservoir interval and the initial interpretation that relied purely on seismic data and geological knowledge. It shows a reasonable conformance with the structural closure and an association with anomalous seismic amplitudes. A white line polygon also shows the extent of the seismic anomaly. The main risk here is the hydrocarbon saturation/seal, as the column height is quite large.

In the 3D CSEM inversion data, an Rv anomaly is present that has a good fit with the seismic amplitudes within the structural closure and reduces the risk of low saturation being the origin of the derived seismic amplitudes. It also confirms the large areal extent of the accumulation.

Figure 1 shows the updated transverse resistance (TR) map that incorporates the CSEM data and the extent of the resistivity anomaly associated with the target. It's important to note the close spatial correlation between both the seismic and the CSEM and the highly resistive feature to the south east of the main structure that was interpreted as being non-hydrocarbon related, based on the seismic indicators of resistive lithologies shown elsewhere in the survey.

As a result of this interpretation, both the probability of success and reserves of this prospect were updated. The target was then drilled and encountered two hydrocarbon-filled reservoir intervals, thereby confirming the interpretation derived from the 3D CSEM data working alongside the 3D seismic and the regional geology.

3D CSEM in salt

The applicability of CSEM when it comes to salt can also be seen in another target in the deepwater GOM. In this case, conducting a resistivity survey through EM and then incorporating the reinterpreted geobodies back into the seismic via migration led to significant benefits.

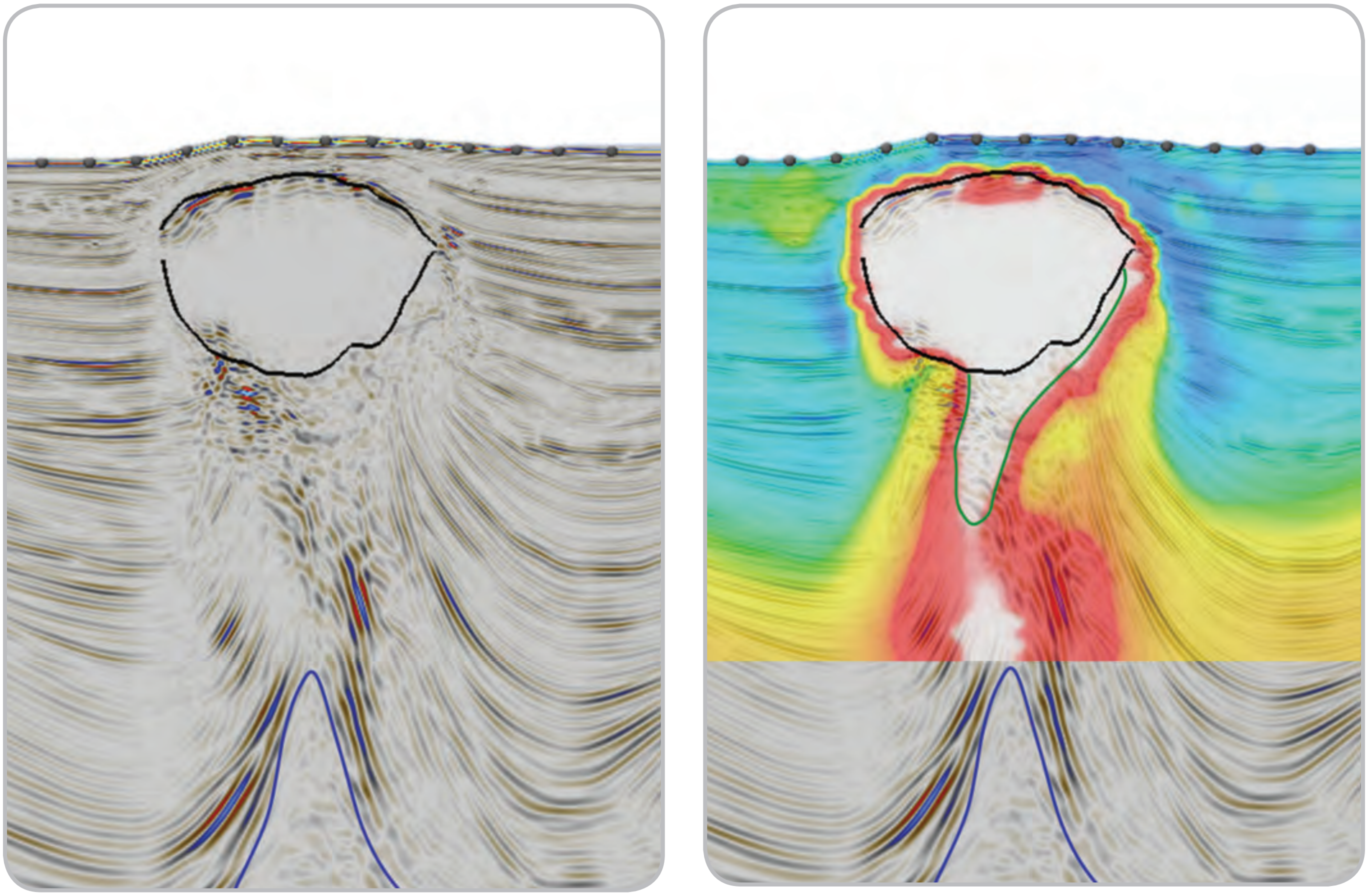


Fig. 2: L – Seismic interpretation. R – Seismic and EM.

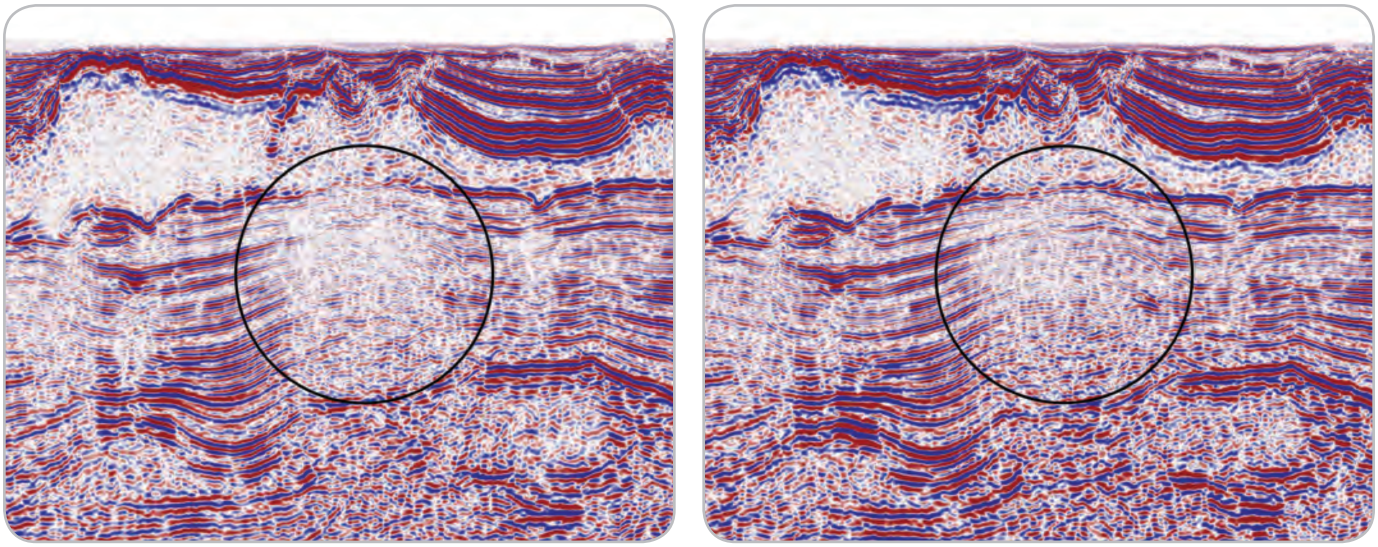


Fig. 3: Subsalt stratigraphy is improved after a joint inversion of seismic and 3D EM data. Seismic data and processing courtesy Schlumberger. **L – WAZ seismic only. R – WAZ seismic and CSEM/MT.**

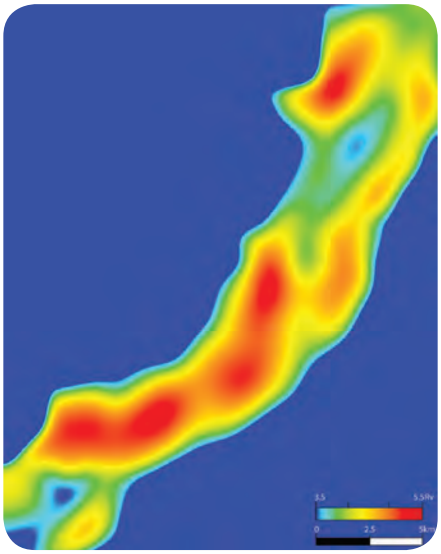


Fig. 4: Wilcox resistivity map from the Daybreak survey in Alaminos Canyon.

The survey targeted a salt diapir with potential hydrocarbon reservoirs at the flanks where 3D seismic was available and where the approximate location of the salt diapirs were known. There was a need to identify AVO responses and improve the interpretation of the salt flank and the base of salt.

Through the acquired CSEM data along with additional data, such as well logs and previously acquired CSEM, a robust initial resistivity model for 3D CSEM anisotropic inversion was established. A vertical and horizontal resistivity grid (TIV anisotropy) defined the model with salt bodies based on seismic data interpretation included in the initial model to enhance convergence in inversion.

Figure 2 shows the results of the 3D CSEM inversion overlain with 3D seismic with the vertical resistivity component illustrated and the black lines representing the salt top and base interpreted from seismic. The 3D CSEM inversion result showed a salt root that was not previously mapped based on seismic data alone.

Figure 3 shows how subsalt stratigraphy is improved after a joint inversion of seismic and 3D EM data with the seismic data and processing, courtesy of Schlumberger.

The imaging results demonstrate that CSEM data has the potential to enhance interpretation in complex salt-affected areas with resistivity data within the seismic velocity model enhancing the resolution of seismic sub-salt imaging. In such cases, a 5-10% improvement in the imaging of the structure post-migration can have a huge impact on future drilling and appraisal decisions.

Looking north

Looking North from Mexican waters and building on the years of experience with Pemex, EMGS has recently completed an 1850sq km CSEM survey in the Alaminos Canyon area of the US GOM.

In one part of the survey in the Great White field, around the Perdido installation, the survey dropped 130 receivers and towed 702km of source lines in 1700-3000m water depth. Receiver nodes were "free falled" into position (with all dropped within specification and 88% within 100m of their planned location) and the source towed 30m above the seafloor to transmit an EM signal into the subsurface.

In this case, the integrated interpretation of CSEM (as seen in the Wilcox resistivity map in figure 4) and seismic has been a valuable tool for companies participating in lease sale 238, with 14 operators submitting 93 bids in August 2014. The CSEM and seismic data will also continue to play a key role in future leasing decisions and well placements in the area.

Accessing different data sources

From basin evaluation and frontier exploration right through to field development, CSEM enables Pemex and other operators in the Gulf of Mexico and around the world to reduce the uncertainties associated with an incomplete geological model and generate a more accurate assessment of the probability of success and reserves estimation.

While seismic continues to be the "go to" technology for offshore exploration, it's only by accessing a variety of different data sources and technologies that a complete picture of the subsurface and its economic potential can be developed. 3D CSEM is a crucial element of this. **OE**

***Vincent Vieugue** is executive vice president of sales & marketing at EMGS. He has an MSc in oceanography and in geophysics from Toulon University and Strasbourg University in France, respectively. Vieugue has worked for over 20 years in the oil and gas industry, starting in 1994 with Schlumberger, mainly within WesternGeco. Vieugue has also worked with Roxar, and he joined EMGS in 2014.*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Barents Sea FTG

Full Tensor Gravity Gradiometry (FTG) is aiding prospect evaluation in a formerly disputed zone of the Barents Sea, adjacent to the Norwegian-Russian border. Dr. Stephen Rippington, Dr. Neil Dyer, and Chris Anderson explain.

Fig. 1: Survey area.

The Norwegian Petroleum Directorate (NPD) is currently offering acreage for license in the formerly disputed zone of the Barents Sea, adjacent to the Norwegian-Russian border (Figure 1).

The NPD has provided comprehensive 2D seismic coverage of the area to assist in the evaluation of the geology and the nomination of the most interesting blocks. In addition, four 3D seismic surveys have recently been completed within the area.

ARKeX has also recently completed a multi-client Full Tensor Gravity Gradiometry (FTG) survey covering the same area.

Industry interest in the area has been very high, with over 30 companies reported to have subscribed to the 2D seismic database. The exploration potential of the Barents Sea in general has been recognized for decades and a variable record of drilling success and failure is testament to the complexity and consequent exploration risk. However, the former disputed zone has, until recently, not seen the same level of academic and industry interest given to the region as a whole, and is therefore still considered to be a new frontier.

FTG presents a relatively new way of measuring the Earth's gravitational field and mapping subsurface structures based on varying density. Directly measuring the gravity gradient in addition to the usual measurement of acceleration due to gravity results in vastly improved data resolution.

Gravity gradients have long been used as a derivative of a conventional measurement as a means of locating subsurface structure with greater precision. Measuring these quantities directly adds confidence, enabling familiar interpretational activities to be performed better while adding a range of novel techniques to be developed, which are compromised with conventional gravimetry measurement. Integration of gravimetry and gradiometry measurements develops the capability to deliver "broadband gravity measurement." This is a valuable dataset, capturing the long wavelength components of the field that are driven by deep structure and the shorter wavelengths that result from mid-crustal and near surface structure.

Fundamental to the value of the broadband gravity measurement is the close relationship between density and seismic velocity. The two properties can be modeled in most circumstances with a common structure, allowing the two datasets to be interpreted cooperatively. This gives the gravity measurement direct relevance to the work of the seismic interpreter.

ARKeX deploys the Lockheed Martin Full Tensor Gravity Gradiometer, which not only delivers the vertical gravity gradient, but the horizontal components (Gxx and Gyy), as well as providing the full-tensor 3D measurement of the gravity field. The full tensor measurement adds resilience to the dataset, enabling the accurate construction not only of the gradient tensor but of a large range of special functions, which may be used to automate interpretive operations such as edge detection.

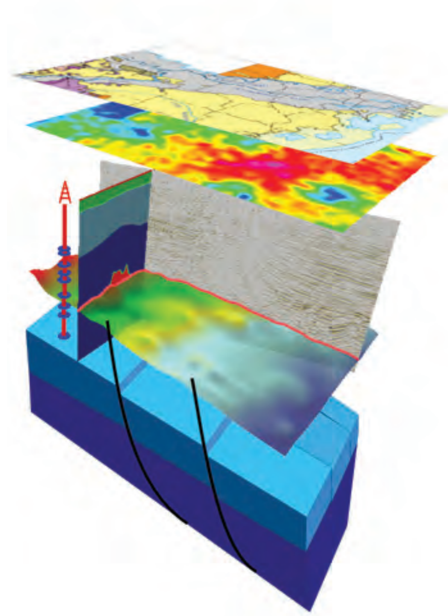


Fig. 2: The cooperative Earth model. Broadband gravity, surface geology, seismic data and velocities and borehole data integrated into the construction of a common model that satisfies all the measurements. Images from ARKeX.

Interpreting FTG data from the SE Barents Sea

The Barents Shelf is a complex tectonic mosaic of cratons, platforms and basins, which amalgamated and deformed through a combination of compressional and extensional tectonic phases. The SE Barents survey area lies in a position where several important structural trends coalesce. Understanding the complex structural geology, at depth and in the shallow section, is crucial for understanding the regional tectonic framework, basin development and prospect-scale risks.

FTG data can be incorporated as part of a multi-physics approach to measure, map, integrate and interpret in context with seismic and other data. The combination of independent data provides additional constraints, which inform and improve the resulting Earth model. The ARKeX SE Barents FTG Survey was acquired in 2013 and 2014. The processed data became available in October 2014, after which a preliminary interpretation was produced to place the FTG data in a regional geological context and to demonstrate how the data can be integrated with other exploration datasets.

The area of interest contains elements of the Finnmark Platform, Tiddlybanken Basin, Fedynsky High, Nordkapp Basin and Bjarmeland Platform. The ARKeX FTG data enable a higher resolution of interpretation than has previously been possible. In particular, the morphology of salt, both in diapirs and grounded within the Permo-Carboniferous section, is defined in unprecedented detail.

Specific issues touched upon in the interpretation report are:

1. The relative influence of Timanian, Caledonian and Uralian structural trends in different areas.

2. Understanding the location and development of late Paleozoic basins.

3. Investigating the location, extent, shape and volume of Permo-Carboniferous salt.

4. The relationship between shallow deformation zones and the uplift, inversion and erosion of large thicknesses of Cretaceous-Paleogene overburden.

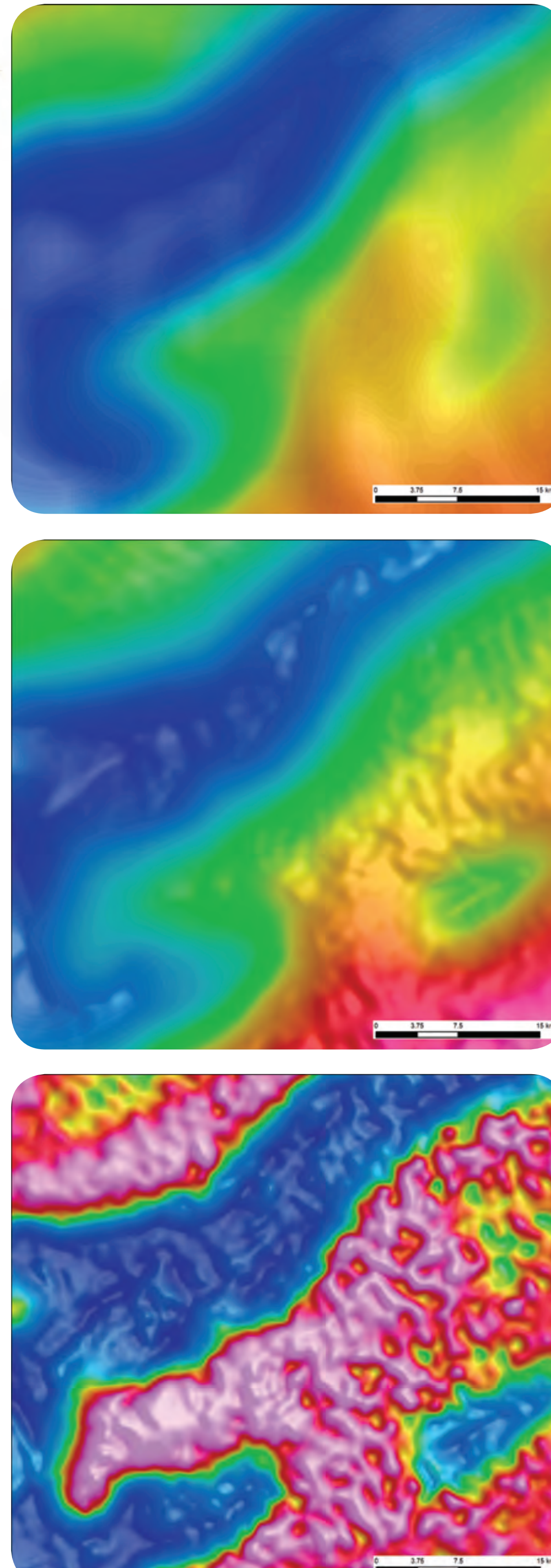


Fig. 3: (comprises 3 images, a, b, and c).

Interpretation methods

The data available for this project were interpreted in two ways:

1. A map-based interpretation of faults, basins, structural highs and salt was constructed in ArcGIS, a geographic information system for working with maps and geographic information.

2. Two 2D/2.5D density models were produced in the XField plugin for dGB's OpendTect seismic interpretation platform (also available as a plugin for Petrel)

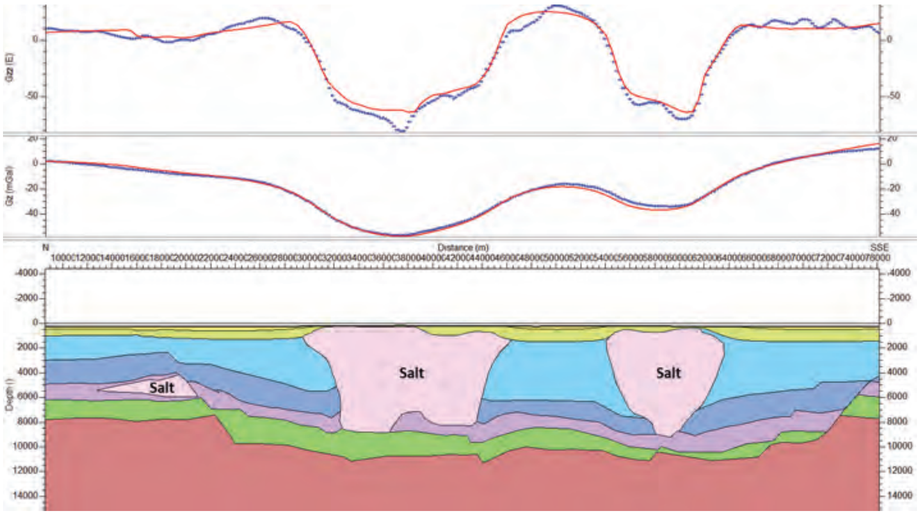


Fig. 4: 2D/2.5D density model across the Nordkapp Basin, satisfying seismic, gravity and gradiometry data.

using images of NPD seismic lines as a guide. XFIELD is a powerful geophysical modelling tool from ARKeX that enables explorationists to integrate and analyze potential field data alongside available seismic data.

The two interpretation methods were implemented in an iterative cycle, whereby one phase of map-based interpretation helps to inform the 2D/2.5 models, which then help to refine the next phase of map-based interpretation. Additional datasets (e.g. published maps and cross-sections) were loaded into ArcGIS to provide constraints on our interpretation.

Results

The following excerpts present some of the findings associated with the Nordkapp basin. The gravity data (Gz) show a single, major high-amplitude negative anomaly in the Nordkapp Basin, on which shorter wavelength anomalies are superimposed. However, the gradiometry data (Gzz) shows a cluster of high-amplitude negative anomalies. These high-amplitude lows correspond to individual salt diapirs, the tops of which have been imaged by the NPD seismic lines.

Figure 3 shows the gravity response over a small part of the Nordkapp basin and compares; a) satellite bouger gravity (Sandwell and Smith 2009), b) Survey Gravity (Gz), and c) Survey Gravity Gradient (Gzz). The gradiometry data contain significantly higher frequencies and provide a tool for delineating salt, but more importantly, windows through the salt into the Triassic and Jurassic succession. These windows may become targets for drilling 'Pandora-type' prospects, in which hydrocarbons are trapped in Triassic reservoirs against the salt flanks.

Figure 4 shows a modeled section based on an original seismic interpretation that was subsequently re-interpreted interactively so as to fit Gz and Gzz profiles plotted above. The profiles show the modeled response in red and the observed response in blue in each case. Note that the higher frequency signal of Gzz is not satisfied with this preliminary model.

The map-view gradiometry data can be used to identify smaller geological features and better define the edges of salt. Furthermore, by interactively fitting a seismic interpretation to an observed Gzz profile, the volume and shape of salt bodies can be better defined. Other features associated with more subtle density contrasts produce smaller amplitude, high frequency anomalies, as seen on the right side of the Gzz profile on Figure 3. These anomalies could be caused by seabed density variations related to the glacial history of the region, and/or shallow deformation zones resulting from the uplift, inversion and erosion of the Cretaceous-Paleogene overburden. Such deformation zones may generate small density variations in the Triassic-Jurassic succession.

This integrated seismic/gravity approach means that seismic interpreters can benefit from relevant high resolution information from gravity measurements in an interactive way. Interrogating the gravity dataset using the appropriate interactive tools (for example the XField plugin for Opendtect or Petrel) from the seismic interpreters' working environment allows a rapid test of interpretational hypotheses, speeding the development of a comprehensive Earth model and increasing confidence This allows further investigation of features associated with sharp density contrast, which often limit seismic imaging.

The implicit coupling of geological insight, often significantly enhanced by the ability to visualize in map view the position and extent of structures interpreted on seismic sections, with geophysical rigor represents an improvement to the relevance of the interpreted Earth model as an active element of an exploration program. **OE**

***Dr. Neil Dyer** is chief technology officer at ARKeX. He has more than 15 years direct experience in the oil and gas sector in interpretation, QA, data processing and integrated "Multi Physics" Earth modeling. Before joining ARKeX in 2006, Dyer held positions with HGS Limited and TGS-Nopec. Dyer has a first-class degree in geophysics and a PhD in environmental science (Volcanology) from Lancaster University.*

***Dr. Stephen Rippington** is a senior geoscientist at ARKeX. Since joining ARKeX, Rippington has undertaken technical work on projects investigating the structural geology of the NE Greenland Margin, the SE Barents Sea and the Faroe-Shetland Basin. Before joining ARKeX, Rippington was as a field/structural geologist at CASP (formerly the Cambridge Arctic Shelf Programme). He has a PhD from the University of Leicester in the UK.*

***Chris Anderson** is executive vice president for business development at ARKeX. He was previously director of sales at WesternGeco, and more recently VP sales and marketing at PGS.*

Benchmarking reliability

The capability to benchmark the reliability of safety-critical well barrier components against a global component test database will enable oil and gas operators to optimize asset performance, Ged Lunt says.

Optimizing asset performance remains a continuous challenge for oil and gas operators. A key element in achieving this is selecting well equipment with reliable performance. However, making the correct selection is far from simple; different equipment models may be more suited to certain operating conditions. When conditions are very challenging, well designs may need to be adjusted to allow for lower achievable reliability of particular equipment to maintain an acceptably low overall level of well failure risk. A lot of considerations lie behind the selection of well designs and the selection of replacement components during well workovers.

The performance of installed well components must be totally predictable. Should a problem arise at any given point in time, operators must be confident that they know how their well barrier components will respond. For example, if they shut a subsurface safety valve (SSSV), then they know with certainty that it's going to close and contain the well fluids in the specified time.

Getting accurate reliability figures for well barrier components requires access to a statistically significant database. While the industry recognizes this need, a key challenge has been the reticence of operators to make data such as component reliability and failure rates available externally.

In addition to concerns over data confidentiality, efforts to build such a database have tended to be limited to single regions such as the North Sea, or focused strongly on specific components such as the SSSV. Previous systems have also been badly structured and suffered from poor quality of data or difficulty of use or access.

Better insight, better decisions

Wood Group Intetech launched a global database of well performance data called iQRA. This online quantitative reliability analysis tool provides operators with access to global well and oilfield component performance information, so operators can identify the highest performing well components, benchmark reliability figures, and extract statistical and mean-time-to

Integrity verification

It is possible to verify that the integrity of a well is robust by analyzing and comparing the reliability of its existing components with those in a reliability database. Engineers can compare new technology against that used in existing components. This provides them with verified data should they need to present evidence to a specific vendor where issues are being experienced with that vendor's product, or to support requests for changes in operational procedures.

When an operator feels that they are experiencing a variation in equipment reliability from field to field for example, the issue may be related to a specific service provider, or certain companies carrying out maintenance procedures with more diligence than another. To be able to demonstrate this quantitatively, the operator can turn to a detailed reliability analysis of their extensive equipment test database.

The following example shows the difference in mean time to failure (MTTF) of two different models of SSSV in gas producing wells to illustrate the variation possible. The outcome of the evaluation of the survivability of the equipment featured in Figure 1 is 75% over the coming five years (i.e. one in four of these installed valves will fail in five years), whereas the value derived from Figure 2 is over 90% (less than one in 10 will fail within five years).

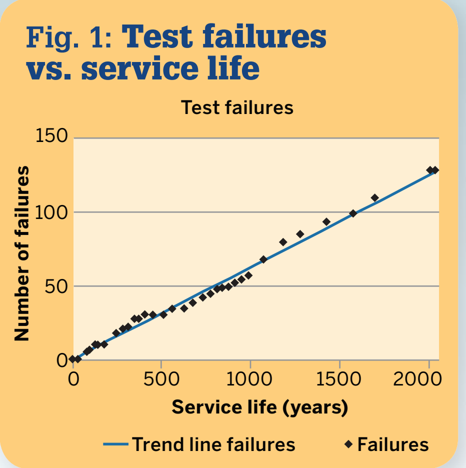


Fig. 1: Corresponds to model with purple triangle in Fig. 3.

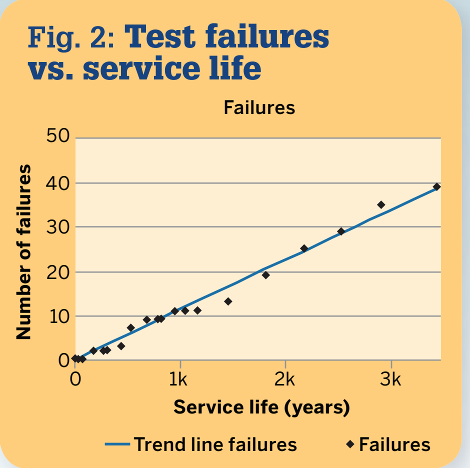


Fig. 2: Corresponds to model with orange triangle in Fig. 3.

failure (MTTF) data to support cost-saving decisions.

Most operators accept that certain well barrier component failures are inevitable and operational constraints may mean that they cannot be repaired immediately. It can be necessary for wells with individual components not in full working order to continue to operate, provided risk assessment indicates the risk level is acceptable. Of course, some types of failure call for the well to be shut-in and repaired immediately, but for the majority of non-critical failures, repairs are scheduled to take place within a designated timeframe, or when the opportunity arises.

Testing can actually reduce the lifetime of the equipment – especially an active component that is opened and shut, each cycle causing some amount of wear and fatigue.

Given that it is necessary to close valves in order to test the leak rate across them, using risk-based analysis to determine that testing can be safely performed less frequently, should extend the lifetime of valves, as well as reducing operating costs.

Access to this kind of reliability information makes it possible for operators to identify where they have low reliability equipment or potentially a faulty component, and pre-empt potential failures on other wells by taking the opportunity to replace equipment if another well intervention is taking place.

A key challenge has been the reticence of operators to make data such as component reliability and failure rates available externally.

Meeting user needs

The ability to benchmark company performance against the global database is attractive for operators, as is the functionality to carry out reliability and MTTF evaluations and the provision of robust and risk-based evidence to present to production managers when requesting that a well be shut-in.

Following the ISO-14224 standard, iQRA also includes failure data analysis, such as critical failures versus degraded failures. These features have been designed to accelerate the industry shift to risk-based assessment and performance-led decision-making for maintenance scheduling.

These capabilities are already enshrined in UK health, safety and environmental practices, and in Norway, where the Petroleum Safety Authority stipulates that each well workover case be assessed per well and based on reliability data. As regulations evolve, iQRA's ultimate aim is to equip operators with the insight to optimize well operations by identifying potential weaknesses in their equipment and pre-empting future issues. OE

__Ged Lunt__ is technology manager at Wood Group Intetech. Lunt has been responsible for delivering the Intetech Well Integrity Toolkit (iWIT) software for well integrity management to clients including the BG Group worldwide operations, Statoil (2000 wells in Norway), Stogit (ENI gas storage company) and Hess Equitorial Guinea. He has extensive experience in analysis of customer well integrity management requirements, in interfacing database systems into the iWIT software and customising iWIT to match company requirements.

Engineers also need to be able to specify components that fail less frequently in operational conditions that are the same or close to those of their assets. They can use a reliability database subset of information that reflects their environmental conditions to select the components by vendor and model. This is particularly useful during an early phase of field development when there is little own-service experience.

It is also possible to compare failure information during the early years to identify whether the failure rate is indicative of a higher rate of burn-in failures. These may indicate manufacturing or material defects in certain equipment sources. This is illustrated in Figure 4, which shows a higher failure rate (steeper gradient of the failures curve) in the early life period. ■

Fig. 3: **Reliability survival function**

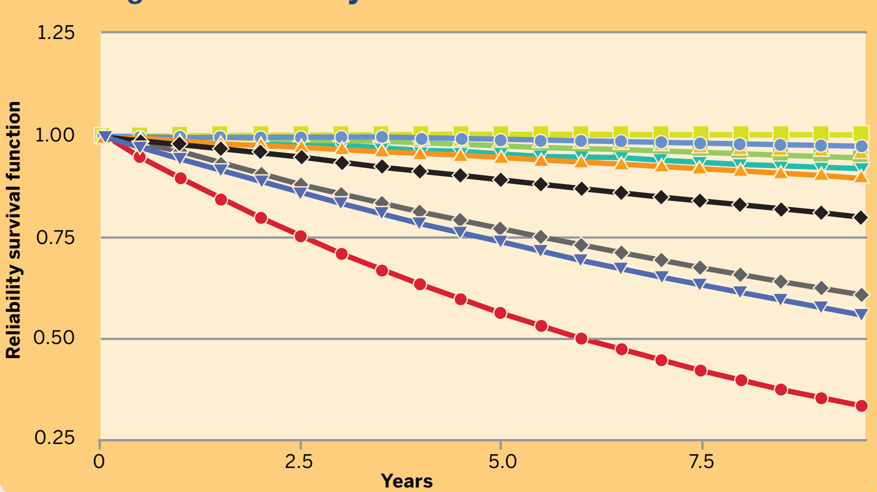
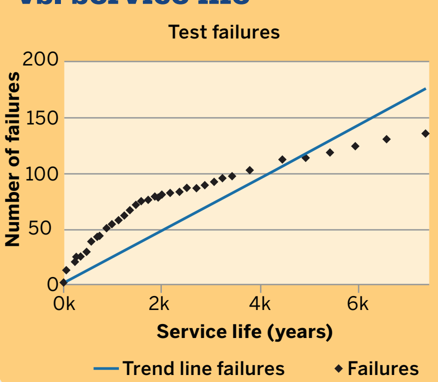


Fig. 4: **Test failures vs. service life**



Taking well control training to new levels

By Steve Redgrave, Director of Aberdeen Drilling School

In October 2012 the International Association of Oil & Gas Producers (OGP) published Report 476 entitled "Recommendations for enhancements to well control training, examination and certification."

This report was produced as a result of the Macondo and Montara well control incidents, and in recognition of the need to develop well control competency. The recommendations of the report are now being implemented worldwide through the International Well Control Forum (IWCF) and the International Association of Drilling Contractors (IADC). The report identified a number of limitations within the existing training structures, and included within the findings were recommendations that:

- Additional technical content needs to be added to the well control training syllabus;
- Clearer guidelines need to be established as to what level of training is needed for each function/role in the operations team; and
- Additional well control training is required for specialist operations.

The need for additional content has been met, as both the IWCF and IADC have either implemented or are in the process of implementing a revised syllabus for each of the certified well control courses.

Human factors are key to the future success of well control and operational training.

Five training levels

Currently being implemented, in line with the above recommendations, is the introduction of five levels of well control training, for drilling and well intervention, from Level 1 through to Level 5. The intention is to make each level more role-specific and encourage a broader range of job roles to undertake well control training.

- Level 1 (Awareness) is a short (3-4 hour) course designed for personnel who are "non-critical to well control operations but may have secondary involvement in well operations and reasonable capability to aid the avoidance or mitigation of a well control event."
- Level 2 (Introductory) has been designed as a 3-4 day course for "all members of the wellsite operations team working in roles which may directly contribute to the creation, detection or control of a well influx."
- Level 3 (Driller/Operator) has been redesigned to focus more on the specific requirements of those personnel responsible for shutting a well in.
- The Level 4 (Supervisor) course is intended for "wellsite supervisory and office-based personnel primarily involved with the well design and operational decision making process."

Further to the changes in syllabus and the emphasis on role-specific responsibilities, these courses are now progressive. IWCF candidates, if they do not already hold the necessary certificate, will have to begin at Level 2 and then progress to Level 3 if they are at driller level before moving onto Level 4 if they work at supervisor level.

- Level 5 (Engineer) has been recommended as an additional course for engineers and front line wells management personnel with a key role in well design. The course is intended to cover those aspects of well control that "need to be embedded into well design, well control equipment selection and rig selection."

The future of well control training

At the time of writing this article, details of the syllabus for the Level 5 course have not been released to the industry (expected to be introduced some time in 2015). IWCF, IADC and well control training companies have been working to implement the recommendations from OGP 476 since its publication. Aberdeen Drilling School, for example, now offers Level 1-4 training courses across both rotary drilling and well intervention disciplines.

Human factors are key to the future success of well control and operational training. Although currently in the early stages of development, training that recognizes and addresses the role of human factors has the potential to create a fundamental change in the industry's attitude towards all well operations.

The human factors aspect of well control has been highlighted in OGP 476 and a further OGP report (OGP 460: Cognitive issues associated with process safety and environmental incidents) that highlights the importance of the appropriate individual and group behaviors and actions in preventing all incidents including, but not limited to, well control incidents. Among these are: situational awareness (being aware of emerging events through the observation of weak signals and being able to predict the consequences); and cognitive bias (the consequence of intuitive short cuts in thinking and decision making).

The changes recommended by OGP 476 are being implemented on a global scale. The well control training industry is in the midst of a positive transition period that I'm sure will benefit the industry and its most important resource: the people working in it. OE

__Steve Redgrave__ is director of Aberdeen Drilling School and IWCF board member. Redgrave has over 40 years' international experience in the oil and gas drilling industry, working for major, and independent oil companies. Redgrave has also published and presented SPE papers on improving drilling performance and been involved in publishing The Technical and Legal Guide to UK Oil and Gas Industry. He is now a leading advocate of the new OGP-recommended improvements to Well Control training, and currently plays a key role on the IWCF Rotary Drilling Taskforce.

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Restarting Rhum

Starting up a high-pressure, high-temperature field prone to hydrate formation can be a daunting task, not least when it has been shut-in and isolated, with the amount of safety critical maintenance limited by international sanctions for nearly four years. That was the task facing BP engineers in 2014 on the North Sea Rhum field. Elaine Maslin reports.

When Rhum first came online, in December 2005, it was described as a world first, due to the high-temperatures and pressures in the reservoir, as well as its 44km-long tieback distance. The largest undeveloped gas discovery in the North Sea at the time, it was expected to access some 800 Bcf of natural gas.

Rhum had been discovered in 1977, some 240mi northeast of Aberdeen in 109m water depth, by BP and its partner Iranian Oil Company (IOC). The field experienced temperatures around 150°C and pressures around 12,700psi. Production started nearly three decades later from two wells.

In 2010, just under four years after first production, the field was shut-in and the system depressurized. Rhum operations were subject to EU and US sanctions, due to IOC's 50% stake, which also meant BP was unable to perform any work on the field, including on any related Rhum topside facilities, on the host Bruce CR platform.

By 2013, there were concerns that if Rhum was left shut-in it could become stranded, should Bruce reach a point in its life where its production dropped to a certain level. Also, there was a concern about the risk to the environment in the event of a leak from the HPHT field, if left unmaintained.

Last year [2014], amid moves to ease sanctions on Iran, the UK government took steps to enable BP to restart production, including temporarily taking over management of IOC's share in Rhum, with IOC's shares of Rhum gas sales revenues being placed in a frozen account. The field came back on stream mid-late October 2014.

How do you restart an HPHT field that has been shut-in for nearly four years with no maintenance, apart from minimal EX inspections on the topsides equipment?

While maintenance was limited, BP did have an idea of what was happening in the reservoir, says Manish Labroo, senior well integrity engineer at BP. A third Rhum production well, which had failed before starting production, had a downhole pressure gauge. "Throughout the four years we knew what the pressures were down there, so we always had eyes on it," Labroo says.

In some shut-in fields, pressure build up can be expected, if there is pressure support from water, for example. Rhum, however, stayed relatively stable, at just under 8000 psi, close to the level it had been when it was shut-in, Labroo says.

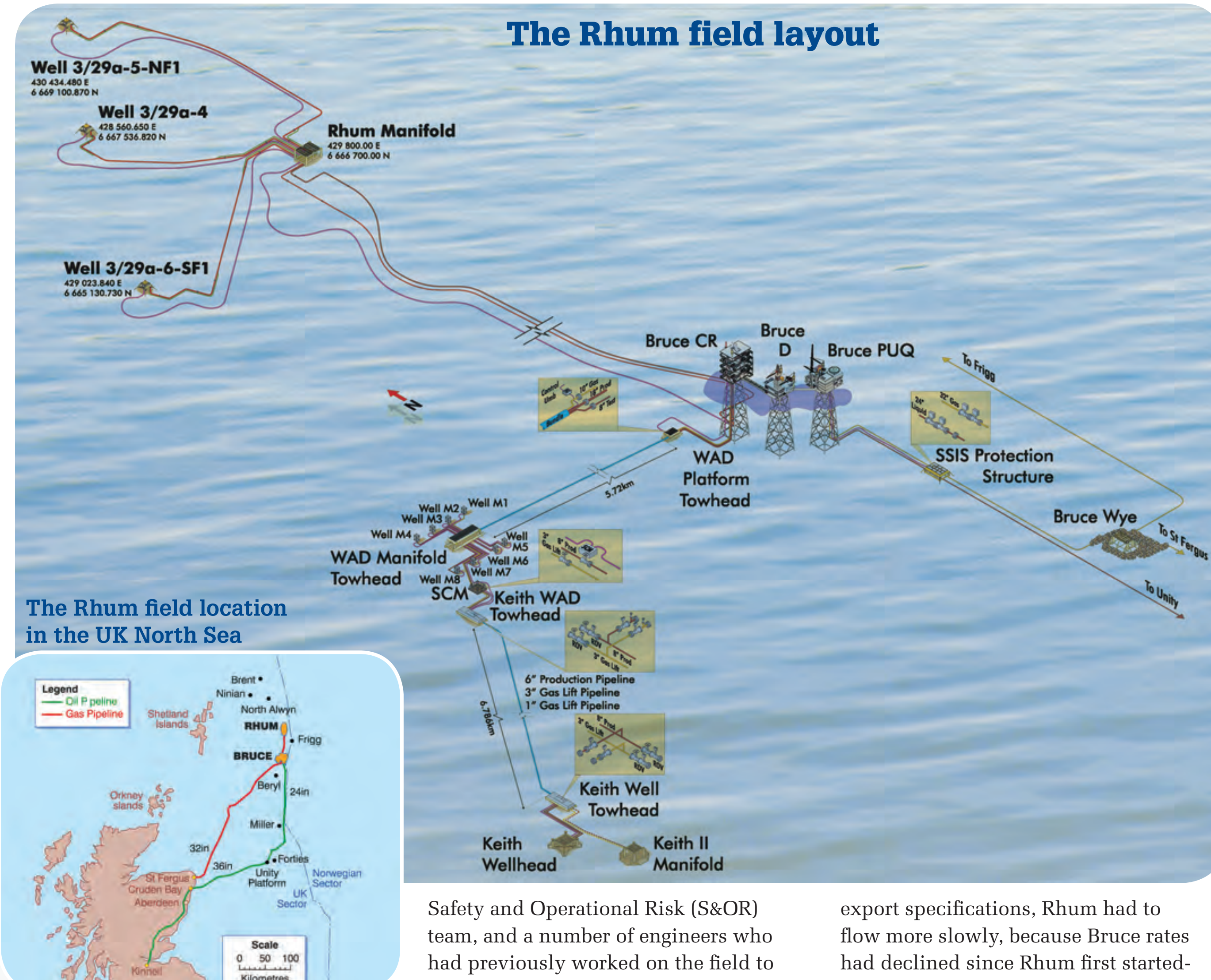
"The fascinating thing was challenges around the hardware, proving it all worked," says Scott Forrester, project manager, Rhum restart, BP. "Up until that point, we had been restricted on what level of maintenance we could do on the system, meaning that no preservation on the equipment could be carried out. We used our maintenance management system and took time to understand all of the work we should have been doing (but couldn't) over the past four years. We also took time to understand where equipment reliability challenges had

The field's infrastructure comprises two producing wells, connected via a manifold, containing a HIPPS, set to trip at 190 bar g, as well as a control umbilical, an industrial methanol spirits (IMS) line and a 44km-long pipe-in-pipe pipeline system back to the Rhum production riser. The 44km pipeline includes a fortified section 300m from the Bruce facilities, designed to protect the platform from any possible rupture.

Topside, there is an inlet separator, with offgas co-mingled with Bruce and Keith gas, to levels which meet Frigg CO_2 specification, due to CO_2 content in Rhum gas. For the different phases of field life, topside routing was via dehydrator inlet coolers, a medium pressure suction cooler, and for late life, a low pressure booster suction cooler. ■

BP's Bruce platform.
Images from BP.

The Rhum field layout



The Rhum field location in the UK North Sea

existed prior to shut in, but where, for the same reasons, we had been unable to take advantage of the four-year shut-in period to work on removing these issues."

Safety critical, environmental critical and production critical work scopes were prioritized with the aim to bring back the facilities to the "status quo." In addition, the entire system topsides and subsea system was assessed by a multi-discipline team of engineers, including the manifold and high-integrity pressure protection systems, to return the whole system from its unpreserved state, in a manner that was safe and compliant with BP engineering standards, involving the function testing and proving of all equipment.

"We took a view that we had just installed it and we needed to prove all the equipment was fit for purpose again," Forrester says. Functional experts from across the business supported the restart with assurance measures, as well as BP's Safety and Operational Risk (S&OR) team, and a number of engineers who had previously worked on the field to provide a peer review of the activities the team were undertaking. "Because it had been shut in for four years, and things would have understandably changed in that time, I made sure we had a lot of people looking at this," Forrester says. The Department of Energy and Climate Change, acting as the manager of IOC's share of the field, were also involved.

Because Rhum's topsides facilities are on Bruce, function testing and proving all the equipment had to take place at the same time as having to accommodate for the fact that there were other priority operational activities on the Bruce platform, not necessarily aligned to Rhum's restart. "It was a careful balance, as the Bruce platform, as host to Rhum facilities, had to be reliable so that we could be confident to flow Rhum fluids during the critical cold start period. Any upset on the Bruce facilities would have been a problem," Forrester added.

There was another consideration for the restart. Because of the need to blend Rhum gas with Bruce gas, to meet CO_2 export specifications, Rhum had to flow more slowly, because Bruce rates had declined since Rhum first started-up. Reduced flow rates meant cooler operating conditions in the pipeline, which meant assumptions in the original Rhum HAZOP and LOPA also had to be checked, and updated, to reflect the changed regime.

One of the key considerations was hydrate formation, says Stephen Blaney, flow assurance engineer, BP. "Rhum is predominantly gas, with a bit of water. Together with the length of the tie-back, this makes hydrate formation a risk," he says. "To manage it, a mix of design features were agreed for the [original] facilities."

To mitigate hydrate formation during normal operation, the pipelines from the controls to the manifold and the 44km pipeline from the Rhum manifold to Bruce, which is also buried, is an insulated pipe-in-pipe system. On a normal shut down, any water that drops out is gravity-drained into even more highly insulated sections of the pipe, to slow down any cooling, so start-up can resume while the liquids are still relatively

BP's Bruce platform.

warm, Blaney says.

When the pipeline was shut-in in 2010, it was depressurized to 9-10 bar g. This meant it was outside hydrate formation conditions (hydrate formation is driven by either temperature or pressure – i.e. high pressure or cold temperatures). But, IMS would still need to be used, both to manage the cold start, from a materials integrity perspective, and prevent hydrate formation as initially cold gas starts to work its way through the pipe.

All of which made the availably of two IMS pumps critical for start-up. But, while they had been function tested and proven, both had seen a level of unreliability before the shut-in. In theory, if they failed during start-up, Rhum would have to be shut-in again, and it would be three-weeks before operations could restart, because, on restart, two pipeline inspection gauges (PIGs) are sent down the export line to ensure the injected IMS fluids during restart arrive at the host onshore terminal in a batch, in order to be processed. Any aborted start-up would mean a third PIG would have to be sent down the export line, which the pipeline would not have been able to accommodate due to the capacity of pig reception facilities.

But, there was an alternative. "When production first started it flowed to a high pressure system," Forrester says. "As the pressure dropped off, it meant Rhum could be routed through the Bruce platform's medium pressure facilities, the current and intended mode of operation for Rhum restart. In future, for late life production, will see Rhum routed to the low pressure facilities."

Routing to the low pressure facilities was the back up if there was an issue with the IMS system.

Production was restarted mid-late October, with the aim to get from cold, or about 7°C – the seafloor temperature – to 20°C operating temperature in about five days.

Late in the cold start sequence, operational issues were experienced on the IMS system and the team reconfigured the system so that the production would flow to the lower pressure facilities, avoiding the need to abort a cold start, because the reconfigured lower operating pressure mode of operation, although not optimized, meant hydrates would not form.

Forrester says it was key to ensure that the changed operating conditions and therefore the change in parameters around hydrate formation were understood amongst the onshore teams, and, crucially, the offshore teams who would operate the plant on a daily basis. It was important that this was communicated effectively, and supported with the necessary training.

"Rhum flow conditions and, in some cases operation in 2014, was different to those in 2010. It was crucial that this was understood, before approval for startup, we needed to ensure that the field could be started and operated safely by competent personnel," Forrester added.

As production returned, the choke was slowly opened and the team watched carefully as Rhum started to flow once more.

"It produces a lot of cold gas, initially," Blaney says, "which slowly makes its way to the platform." This takes about 36 hours, by which time the temperature at first drops, before quickly warming up.

It is a crucial period. Little can be done in physical terms to assess what is inside the pipeline before production reaches the platform, or how the flow regime is operating. However, OLGA simulations can be run to at least assess what most likely will happen. And it all went to plan, Blaney says.

Rhum is now operating normally, once again producing about 5% of the UK's domestic gas needs. OE

Unlocking marginal fields

The pressure is on to find economically viable ways to develop marginal fields, in the UK North Sea and further afield. Ben Smith and Ed Randall look at the challenges and options.

More and more emphasis is being placed by operators and governments on exploiting reserves that have previously been deemed uneconomic – in other words, marginal oil fields.

Often conventional solutions prove too costly or unsuitable for marginal fields, so more novel and innovative designs require due consideration. Atkins has developed extensive experience in developing such designs.

What are marginal fields?

Marginal fields typically share one or more of the following characteristics that can result in high risk to returns on capital investment, heightened sensitivity to oil price, or escalation in Capex and Opex during field development:

- Low exploitable reserves and/or initial production rates (typically 25-50 MMbbl and between 10,000-30,000 bo/d respectively)
- Uncertainty in extent of the proven reserves, field life, production profile or reservoir geology
- Difficult access to export routes – i.e. stranded assets
- Other factors including low gas oil ratio (GOR) impact on power generation, the need for enhanced oil recovery, or difficult reservoir fluid characteristics (high wax and wax appearance temperature, H_2S or CO_2, heavy oil etc.)

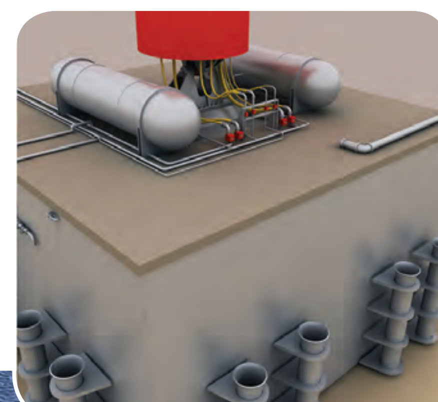
Where these factors apply, it is often more practical to ask the question "given an assumed production profile, oil price, Opex and Net Present Value for the estimated reserves, what is the maximum Capex that still ensures an attractive return on investment?"

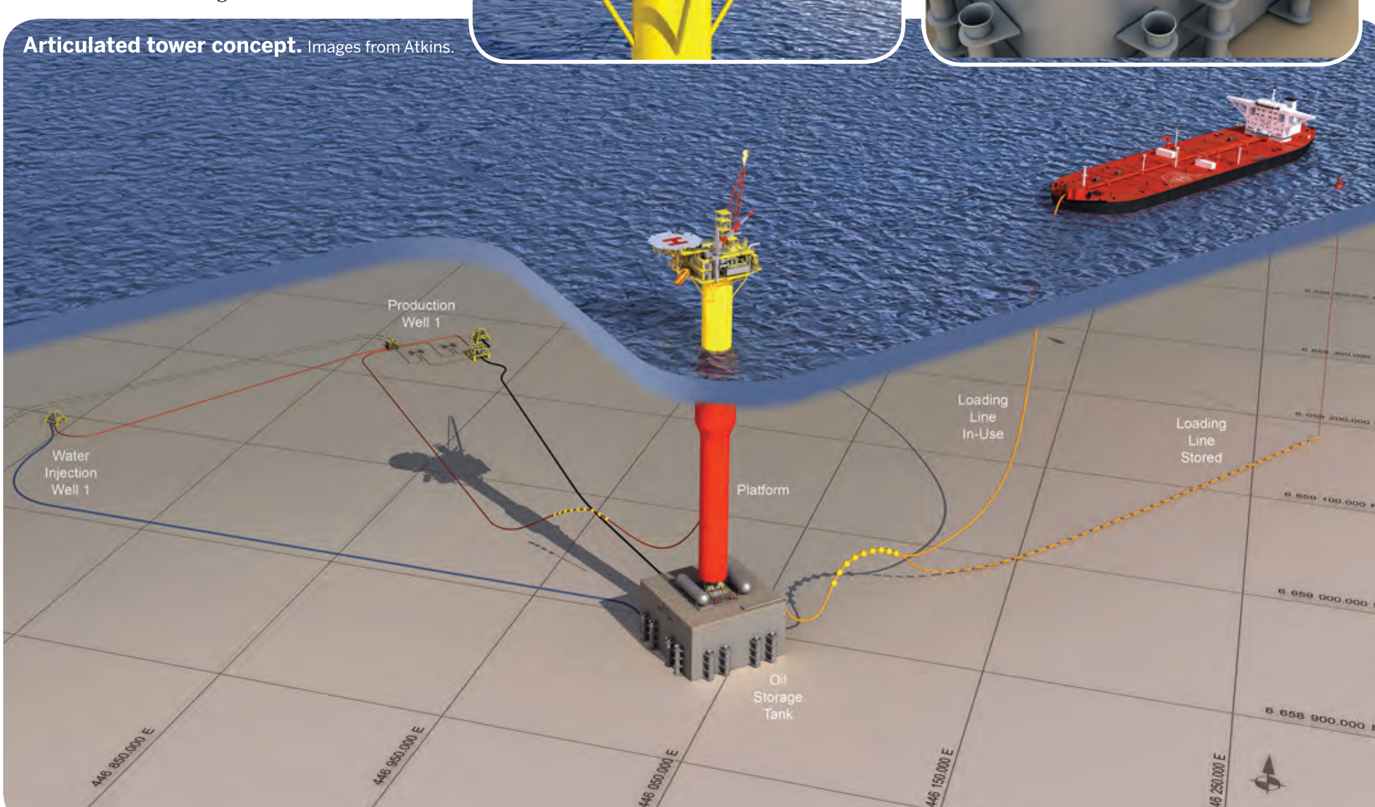
Characteristic solutions

In performing concept engineering and selection, there are a number of guiding questions that we have found useful:

1. Is it marginal in production volumes, a stranded field, or both?

2. What is the most practical/desirable subsea design? From the number of well completions, field layout, need





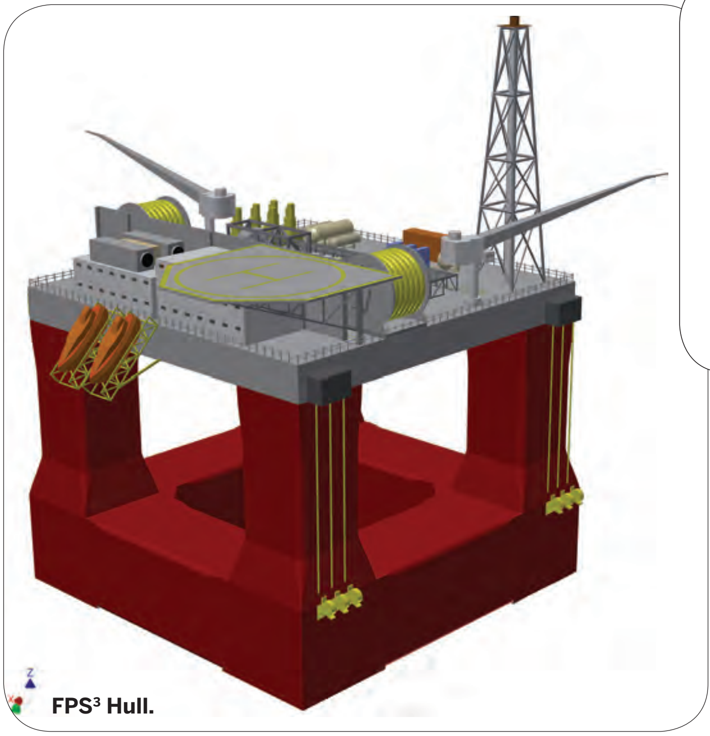
Articulated tower concept. Images from Atkins.

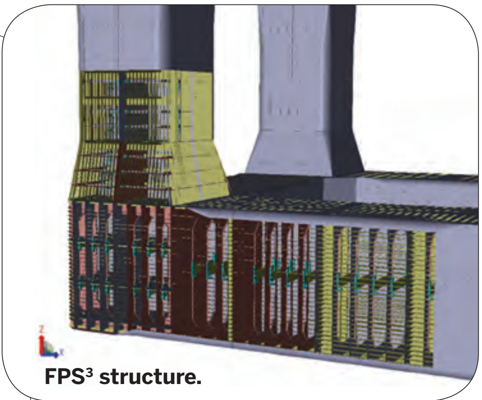
for through life drilling or well intervention, dry or wet trees?

3. Is the field short-lived? Do we need a re-usable solution?

4. What are the limiting factors in water depth, met-ocean and other environmental parameters?

5. Can we also drive toward an inherent level of safety – de-manning and automated operation, maintenance and intervention to reduce Opex?


FPS³ Hull.


FPS³ structure.

On the UK Continental Shelf (UKCS) alone there are a number of innovative options specifically designed for small fields that attempt to answer these questions. These include operating assets, such as the Sevan 300s, operating on the Chestnut and Huntingdon fields, and those in planning including Arup's ACE Platform, destined for the Bentley oil field, and a range of production buoys (*OE*: May 2014).

The following examples demonstrate how some of the above questions have been answered across a number of projects carried out in Atkins. A key theme running through these examples is that of combining a relatively old idea – oil-over-water storage – with modern approaches to managing safety and potential environmental impact.

Stranded fields and subsea tanks

For remote fields where the reserves cannot justify the cost of installing a pipeline, subsea tanks are often a viable alternative to a floating storage and offloading unit. The technology is mature with multiple examples where it has been successfully employed. In a previous study for a UKCS marginal field, by careful iteration between process and structural design, Atkins devised a low-weight facility that minimized overall Capex by combining a subsea tank and an articulated tower to support a normally unmanned installation.

The compliant tower is tuned to avoid environmental loading, as opposed to the use of rigid restraint provided by conventional fixed structures. The steady wind and current loads are resisted by the floating stability of the column – which has its center of buoyancy below its center of gravity, achieved by using solid ballast.

The concept was deemed sufficiently robust by investors to allow further drilling in the area resulting in an increase in proven reserves allowing a more complex facility with higher topsides weight to be justified utilising a conventional jacket. The tank was retained and progressed through to detail design by Atkins.

One particularly innovative feature of this subsea tank is that it is not open to the sea (free venting) but has a "closed loop" connecting both the sea-water and oil portion of the tank with the topsides production facility. This removes the need for subsea pumps, reducing complexity and environmental risk.

Reusable, floating production systems

Various forms of floating production systems satisfy the fundamental requirement for re-usability, and lower initial Capex (through lease/charter arrangements), becoming a "go-to" solution for marginal fields. However, not all traditional FPSOs are necessarily suitable for marginal fields for various reasons including:

1. Tanker conversions (e.g. Aframax size vessels) are just too large and expensive, or lease rates are too high, for very small fields

2. FPSO turrets are high Capex items, which have many complex bespoke aspects in their design and installation

3. Traditional ship shaped hulls, particularly smaller hull forms, are not ideally suited to harsh environments

The need for more small, low Capex solutions, particularly for harsh environments, suggest a further "sharpening of pencils" is needed – the following two examples illustrate how this could be achieved. Both use of oil-over-water storage, to reduce hull steel-weight and cost, capturing the benefits of the subsea-tank, but providing mobility and re-usability.

A semisubmersible solution – FPS³

In extreme environmental conditions a semisubmersible hull form offers clear benefits. To suit a UKCS field, Atkins developed a production and storage semisubmersible termed the FPS³. The design drivers included the need for a large and flexible deck space and payload, low Capex (of order US$250-400 million), safe access for inspection and provision against environmental impact.

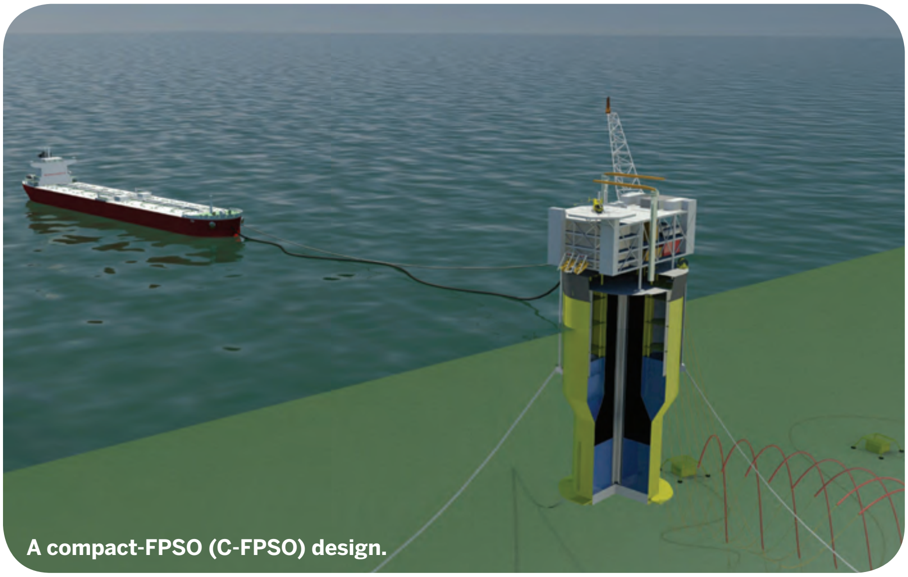
The deep draught hull tunes its motions away from the local peak wave period giving it excellent motion characteristics for a northern North Sea or West of Shetland environment.

The choice of oil-over-water storage reduces segregated ballast water requirements significantly. The cargo tanks remain pressed full of liquid (oil/seawater) at all times, such that there is no free-surface effect to reduce reserve of stability; no vapor spaces that might lead to enhanced explosion risk, and minimal movement of the cargo KG throughout the operational cycle. This arrangement reduces steel-weight and substructure fabrication costs significantly.

The FPS³ was configured for up to 300,000 bbl storage, which allowed it to be used either:

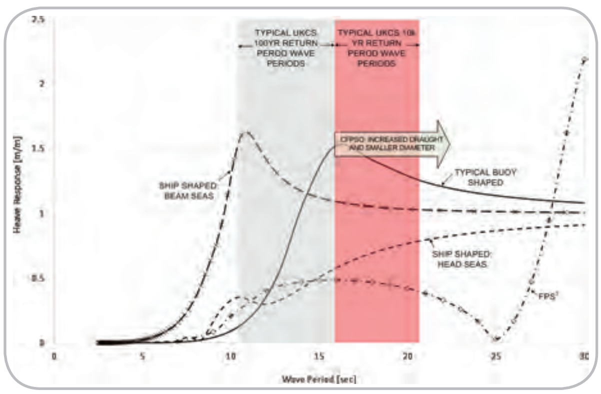
a) As a pure marginal field solution in harsh environments (production rates of up to 25,000 bo/d)

b) To develop larger fields with higher initial production (e.g. 50,000 bo/d)



A compact-FPSO (C-FPSO) design.

producing into an attending shuttle tanker, with the storage capacity as "buffer" whilst the attending tanker is off station to unload. As oil production rates drop later in life the smaller Opex facility is better matched to the size of the field.



Heave response and wave period charted.

A compact-FPSO (C-FPSO) design

The FPS³ demonstrated that there is room for further innovation in FPSO design for marginal fields. Can we develop an even lower cost solution for yet more marginal fields that might be constructed and installed for no more than $250 million?

In two studies for North Sea fields with an estimated life of 7-10 years, Atkins developed a small deep-draft buoy with a single central oil-over-water cargo storage tank combined with a conventional integrated topsides. This innovative concept serves as a low Capex – low Opex solution and provides processing and offloading facilities on the smallest platform "footprint" affordable. The key features of this patented concept (GB2507370) are outlined below.

▪ **Hull form**

The C-FPSO's deep draught near symmetric hull form gives beneficial motions characteristics similar to those of a SPAR. Heave plates also give the concept inherently high natural periods. The motion is relatively insensitive to wave direction which allows the unit to be spread moored thus removing the need for the turret and swivel found on conventional weathervaning FPSOs.

For a conventional offshore structure such as a semisubmersible, or ship-shaped unit, wave loads typically govern the structural design and often limit the operational fatigue life due to global loading. For the C-FPSO, the global wave loads are at a minimum and the internal arrangement is set out to focus on load carrying horizontal hydrostatic pressure. For this reason the structural design of the hull is surprisingly simple. By making use of a conventional stiffened plate structure and simple symmetric repetitive design; the overall construction risk and engineering timescales from concept design to unit delivery are minimized.

▪ **Topsides and operation**

The C-FPSO has been designed to accommodate a conventional integrated topsides payload in the range of 4500 to 6500-tonne – depending on storage capacity. The integrated topsides allows this design to maintain a distinct separation between the production fluids process systems, power generation and accommodation, and the hull systems, including cargo storage and offloading. This simplifies construction and installation and gives flexibility in re-use of the facility.

During production, the cargo is fed into the top of the single oil-over-water cargo tank, and displaces water removed from the bottom via a central caisson, treated and discharged overboard. Only small compensating ballast tanks are required to maintain draft and meet damage stability requirements. At offload, cargo pumps on the topsides deck transfer the crude via an offload reel on the weather deck to a shuttle tanker while sea water is pumped into the cargo tank from below.

Risers are routed via a hang off frame located on a cellar deck of the topsides. All hazardous process equipment is kept in open and freely ventilated space, and provides good, multiple access to emergency escape routes, even on this very small facility. Minimal marine facilities reduce persons on board requirements significantly.

Conclusion

It is becoming increasingly important to look for means to exploit economically marginal fields that may be remote, have short production life, extreme environmental conditions or flow assurance difficulties. The "closed-loop" oil-over-water approach has helped develop some particularly cost-effective approaches to exploiting stranded and marginal fields, safely and environmentally. It is clear that in order to continue to drive down Capex, particularly in an era of uncertain oil price, much smarter engineering combined with better ways to manage technical and economic risk is required. OE

Ben Smith *is a naval architect within the Oil and Gas business at Atkins based in London. He joined Atkins in 2010 principally focused on the design of assets for marginal fields. He graduated with an MEng from the University of Southampton.*

Ed Randall *is a chartered naval architect with a focus on early stage design where maximum value can be added. He has project managed multi-disciplinary concept, FEED and detail design projects and leads the floating systems team in London. Randall holds an MSc in Naval Architecture from the University of Southampton.*

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- ☐ 04 Geology, Geophysics, Exploration
- ☐ 05 Operations *(All other operations personnel, Dept. Heads, Supv., Coord. and Mgrs.)*
- ☐ 99 Other *(please specify)*

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

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

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

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

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- ☐ 102 Drilling
- ☐ 103 Subsea Production, Construction *(Including Pipelines)*
- ☐ 104 Topsides, Jacket Design, Fabrication, Hook-up And Commissioning
- ☐ 105 Inspection, Repair, Maintenance
- ☐ 106 Production, Process Control, Instrumentation, Power Generation, etc.
- ☐ 107 Support Services, Supply Boats, Transport, Support Ships, etc.
- ☐ 108 Equipment Supply
- ☐ 109 Safety Prevention & Protection
- ☐ 110 Production
- ☐ 111 Reservoir
- ☐ 99 Other *(please specify)*

Dockwise Shipping loads out the SHWE platform.
Photo from Dockwise.

Great expectations

As the offshore industry grows in complexity – in terms of projects and geographies – software is playing an increasing role in engineering, both to aid engineering and collaboration, as projects increase in complexity and diversity. Meg Chesshyre learned more at the Bentley Systems' Year in Infrastructure 2014 conference in London.

Software is playing an increasingly large role in the offshore oil and gas industry, both as an engineering tool but also providing the glue between the ever more global and widely distributed workforce, not least when it comes to platform installation projects.

For Bentley Systems, the growth has been notable. Clark McDonald, Bentley's vice president, global offshore engineering, says the increasing use of floating production systems means there is a growing market for Bentley's offshore software products.

He says that in a period of just three years there has been a 100% increase in terms of the revenue associated with the sale and delivery of offshore software, which represents about 10% of Bentley's annual turnover of a little over US$600 million. Offshore wind turbine arrays is also a very strong business area for Bentley. It is relatively large in Europe and growing in Southeast Asia, offshore China, Korea and Japan - post Fukushima.

Bentley Systems also bought MOSES analysis software just over a year ago, a suite of analysis software for the installation of offshore structures and the design of all types of floating offshore systems. It provides hydrostatic and hydrodynamic analysis, used by the likes of Dockwise for floatover projects.

MOSES brings additional capability to Bentley's existing range of products, which includes flagship product, SACS, an integrated suite of software for structural analysis and design of offshore structures, including oil, gas, and wind farm platforms and topsides.

Centrica's F3-FA self installing platform being transported offshore. Image from Orca Offshore.

For Bentley, some of the key trends in the industry are about those using the systems, how they want to use systems and where they're using them from.

Phil Christensen

Phil Christensen, vice president Offshore & Marine, says, in terms of software system user age, there is an age gap between the developed markets, where the average user age was probably in the 40s, and the developing markets, like Southeast Asia, where the average age was more in the 20s. These two groups have pretty different expectations of how software should work, he says. Bentley's approach, he says, is an aim to achieve a "best of both worlds" approach, keeping the old, world-proven solver, but adding modern graphical capabilities to improve the ease of use.

Christensen also says there's an increased geographical distribution of project teams, and the increased collaboration between different departments, particularly marine and structural. "As projects get bigger there has got to be a lot more technical collaboration between the teams as well as human collaboration."

SHWE

As an example of where collaboration between different departments across geographies was the SHWE jacket transportation and installation, offshore Myanmar, carried out by Dockwise.

The project won Bentley Systems' 2014 Be Inspired – Innovation in Offshore Engineering award. Dockwise was tasked with the transportation and installation of the SHWE (meaning gold) jacket and topsides with deck support frame at the Bay of Bengal by EPCI contractor Hyundai Heavy Industries. Dockwise performed the operation and engineering for the jacket transportation, jacket launch, topsides transportation, and topsides floatover. The jacket weighed 22,000-tonne and the topsides 30,000-tonne.

Bentley Systems' MicroStation and ProjectWise were used by team members in project offices located in The Netherlands, United States, and China. An innovative bottle-shaped barge design to transport these massive structures was produced using MOSES and SACS, and data access, accuracy, traceability, and workflow were addressed by managing files in ProjectWise. Efficiencies achieved during detail design saved 5000 man-hours of the 30,000 engineering hours.

Simulations conducted using MOSES and SACS cut the estimated topsides floatover time from four days to two days. Safety considerations during simulations allowed the installation to be performed without incident. Being able to transfer data between SACS and MOSES increased project efficiency.

With a vertical center of gravity 48.3m above the keel, the topsides' stability requirements pushed the limits of the installation barge, *HYSY 229*. The bottle-shaped barge made the floatover operation feasible because it satisfied both the stability and jacket footprint requirements. However, it created challenges for the mooring arrangement and transportation global strength needs. The short, fat, and heavy jacket also brought challenges to the launch operation.

The runners up for the award were Orca Offshore's transportation and installation analysis of the F3-FA self-installing platform and SNC-Lavalin's Mariner field development detailed design project.

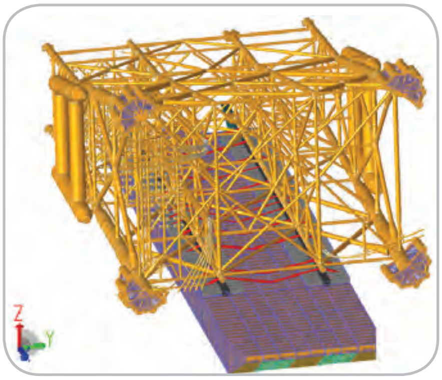
A Dutch Orca

Orca Offshore performed transport and installation analyses for Centrica's £200 million self-installing gas platform in the Dutch sector of the North Sea. The F3-FA platform has a suction pile foundation resting on a temporary barge for transportation. It can be relocated, providing significant cost savings across three to four fields.

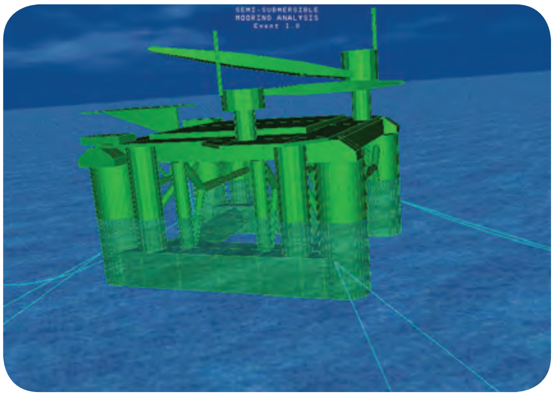
Orca's scope of work included motion and stability analysis, multi-body dynamic analysis, structural spectral analysis, and scale model tests. It was crucial to know hydrodynamic loads early in the project due to the pile size – 15m-high and 15m-diameter – and proximity to the wave zone. The loads determined how to size the steel work. MOSES determined those loads and confirmed the structural strength of the platform. The use of MOSES reduced the amount of steel required in the platform and for sea fastening and proved

Engineering Mariner

Statoil awarded SNC-Lavalin the front-end engineering design contract for its massive 22,000t jacket at the US$7 billion Mariner oil field development in the UK North Sea. With an 88m X 62m footprint on the seabed, the 120m-high jacket supports a topside facility weighing around 54,000t. The jacket's weight and subsequent installation by barge were significant challenges. Using SACS and STAAD.Pro, SNC-



Statoil's Mariner jacket.
Image from SNC-Lavalin.



MOSES semi-submersible mooring analysis. Image from Bentley Systems.

Lavalin completed the jacket design in a tight timeframe. Nineteen interrelated analyses were performed effectively using SACS' various modules, including wave-loading under storm conditions, seismic response, fatigue, sea-transportation, and accidental impact. STAAD.Pro was used for the detailed design of secondary steel. Working with the same software as the topsides designer enabled efficient information sharing and modeling of the interfaces between jacket and topsides.

Bentley also highlighted the OSX-3 topside design, which was a finalist for the Be Inspired award in 2013, Bentley software helped reduce the OSX-3 FPSO topside steel weight by 10%. L&T-Valdel Engineering, headquartered in Bangalore, was commissioned by MODEC International to provide modularization design for the FPSO topside. The challenge was to complete the design of 15 modules and 10 pipe racks within 10 months. The company used SACS for modeling, analysis, and optimization of the FPSO topside structure and STAAD.Pro to design its tertiary steel. SACS achieved a 10% overall reduction in steel weight per module/pipe rack compared with conventional design. SACS provided clear visualization of lifting arrangements and detected structural clashes. STAAD.Pro's helped the team complete the project on time.

Vessel design

In addition to MOSES and SACS, Bentley also has a vessel design system called MAXSURF for the initial hull design of new vessels and review of stability for modifications to existing vessels.

Having SACS and MOSES in the same company has lead to enhanced interoperability, says Bentley. There is also full integration between SACS and ProjectWise, and mechanical/structural integration between AutoPipe and SACS. There are plans for the future to create i-models automatically, and for increasing use of cloud computing. I-models are a medium for information exchange within projects associated with the lifecycle of infrastructure assets. They facilitate the sharing and distribution of information regardless of the source and format of the information.

Bentley says it continues to invest in product development, with major releases every nine months or so. MOSES V7.1 was released in September 2014. Christensen says: "This first major release of MOSES since Bentley acquired it in October 2013 increases the software's interoperability and extends the resulting information mobility. For starters, it offers an enhanced ability to import SACS structural models into MOSES, along with the automated generation of SACS loading files from MOSES – enabling collaborative workflows among offshore structural engineering and naval architecture teams.

"In addition, through MOSES V7.1's support of integrated structural modeling, users are able to work within integrated and flexible structural modeling, analysis, design, documentation, and detailing workflows. This gives them the advantages of intelligent structural design practices, which can help them deliver offshore platforms faster while reducing project risks. **OE**

40 years rigless: where are we now

Contemporary MSV used for rigless projects.
Photos from Reaching Ultra.

The previous article Rigless Origins (*OE*: March 2014) detailed the Zakum project, which was carried out in 1969 offshore of Abu Dhabi, where all methods of running wireline from a vessel—in open water—were executed and assessed[1] [2]. More importantly, the article captured the evolution of rigless methods and techniques in regards to the subsea lubricator, soft riser, and submersible winch method, while employing a now versus then approach to show where the aforementioned technologies presently stand. A similar approach will equally be used in this follow up article to demonstrate—in greater detail—how today's multi-service vessels (MSV), and subsea and rigless

A topside acoustic system used to engage subsea accumulators.

Coiled tubing running through a vessel's moonpool.

intervention equipment/methods have evolved to meet the demands of contemporary rigless light well interventions (RLWI).

Size disconnecting: vessel comforts

One of the key findings made at Zakum was the need for "larger and better equipped [vessels to conduct] operations in deeper water and more exposed areas"[2].

Comparatively speaking, today's MSVs are better suited for such deepwater environments as exemplified by their use at depths in excess of 3900ft when operating in a rigless fashion[3].

Conversely, the forward bridge dive vessels—*Sharifah* and *Ajax*—used at Zakum operated at very shallow water depths [1] [2]. In spite of these advances, today's MSVs must contend with having to keep station during deepwater operations (Station keeping was also a concern at Zakum). Furthermore, a glitch on an MSV's station keeping system can cause it to lose station, leading to a drive off, resulting in brash and uncontrolled tugging of topside to subsea conduits that tether a vessel to a fixed subsea point.

Protective measures to prevent tugging is key, which is due to the fact that these conduits make it possible to intervene and communicate with a well, without a marine riser. For this reason, it is of the utmost importance that conduits have the ability to disengage—in an emergency, independent of a remotely operated vehicle (ROV), or an intervention workover control system (IWOCS)—while facilitating the following: Parting and sealing on wireline (slickline and E-line) via a blow out preventers' (BOP) rams when employing downhole tools; ejection of an umbilical via a hydro-mechanical "kick off" junction plate to separate the couplings which provide hydraulics and chemicals to an intervention kit; and the disengagement of rigless through bore connectors that make it possible to communicate with a well via a quasi-flexible medium such as coiled tubing.

Contingent disconnections

It is important to note that failing to disengage any topside to subsea conduits during anomalous conditions is highly detrimental, which can cause them to part, while adversely affecting both topside and subsea equipment. Because of this, accumulators and mechanical weak links are paramount for disengaging said conduits in a safe and controlled fashion (All conduits must be able to isolate/seal off at their disengament point).

Functionality-wise, weak links work by being tugged or pulled via an external wire or apparatus that attaches to a topside to subsea conduit—such as a wire strapped to coiled tubing—to release a through bore connector, for example; conversely, subsea accumulators operate by storing and quarantining the needed pressure and flow, to close the rams on a BOP via a set pre-charge, which ensures that the rams' close at a fixed and set time. This is driven by the American Petroleum Institute.

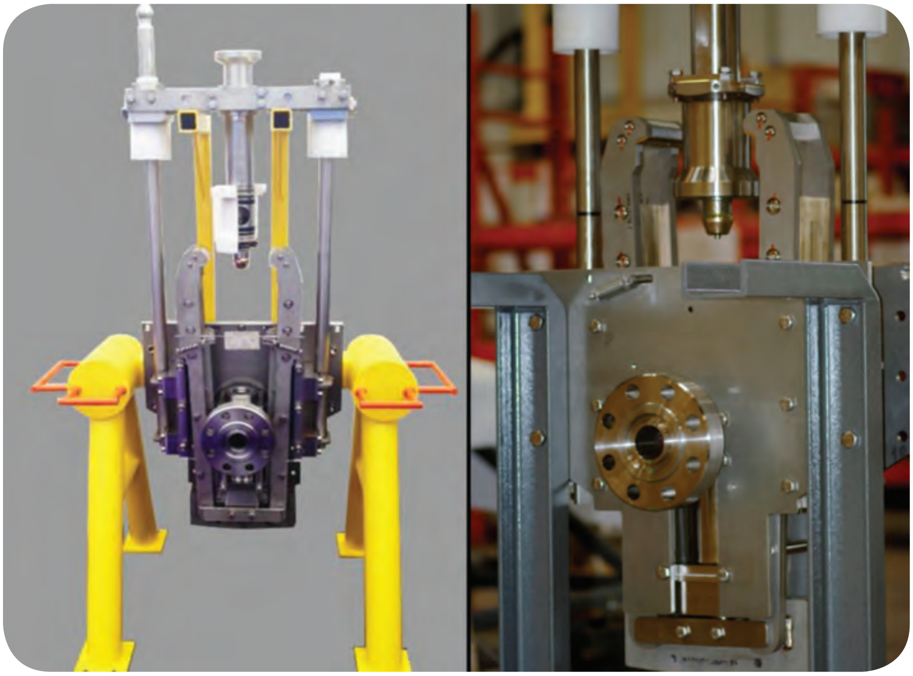
The use of weak links and accumulators is key in not only mitigating anomalous vessel conditions, but to equally allay adverse weather, and downhole conditions. Furthermore, the release of an accumulator's stored energy requires setting off an external trigger, such as a topside acoustic system. It must be noted that due to Zakum's depth, the use of accumulators and mechanical weak links for contingent disconnections were not addressed.

Post disconnecting

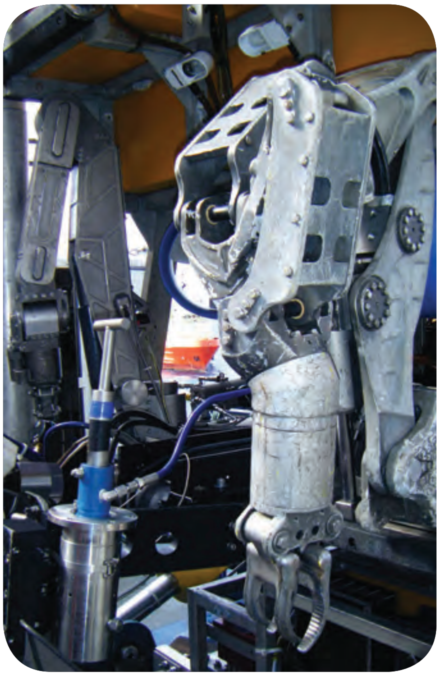
The authors also recognized the need for vessels to be of "sufficient size and comfort to remain on location during severe weather" after the closing of operations[2]. In spite of the advances made over a 40-year span, it can be difficult for MSV's to remain on location during

Subsea accumulators, which are mounted on rigless kits.

A four-point anchor vessel on standby during a RLWI project due to weather conditions.



(Left) A cut through view of a through bore connector. (Right) A connector prior to being fully mated Photo from SECC.



17H hot stab mounted on an ROVs porch. Photo from Reaching Ultra.

volatile weather, resulting in vessels having to return to dock while conditions subside.

It is imperative to highlight that once a vessel has disconnected during harsh weather—and operations are closed—that all topside to subsea conduits be recovered in a controlled and methodical manner. In addition, all conduits and associated equipment must be able—by design—to withstand volatile recovery conditions until they can be safely brought above the water line, or to a predetermined safe zone. Failing to execute the aforementioned can cause the disconnected conduits to crash or become entangled. A more severe scenario is one where conduits become intertwined with subsea assets. For this reason, having a safety procedure/protocol in place for the immediate spooling up/recovery of conduits, during anomalous weather, is of high benefit.

Resume work

The need to immediately resume work after severe weather passes was an additional recommendation for the future[2]. At present, this is achieved by remating the previously mentioned kick off junction plates and through bore connectors. This section, will focus on the latter, as they enable the execution of more than just wireline work, and facilitate communicating with a well in the absence of well control equipment, such as a BOP, when acidizing wells: the authors correctly inferred that this type of work would be conducted in the future from a vessel.

From a mating standpoint, through bore connectors work similar to 17H hot stabs, in that they require mating a male (This end attaches to a coiled tubing line) to a female mating end that is located on a pump in port on a rigless kit. In addition, through bore connectors and 17H hot stabs greatly differ, since fluid pumped through the former is measured in barrels per minute, while the latter's flow rate is measured in gallons per minute. Additionally, said connectors are specifically engineered to mechanically lock the male (stab) within the female (bore), and require an external trigger (weak link) to unlock the male end.

Application-wise, through bore connectors are conducive for acidizing wells where large volumes of chemicals/cocktails need to be introduced in to a well, to reverse their decline in production. However, through bore connectors can also facilitate dewatering, flushing, abandoning pipelines, placing cement plugs, and pumping of kill fluids to plug and abandon (P&A) a well – without the use of a rig.

Conclusion

The future of rigless intervention technology, post-Zakum, will continue to have inherited challenges and obstacles. Notwithstanding, the rigless community and ancillary participants, have not only technically addressed such challenges and obstacles, but have equally, as demonstrated above, developed innovative techniques and unconventional technologies to safely and properly execute in an open water setting. The result: tripling the depth of projects in a span of five years, while furthering the proof of concept of rigless technology [3]. **OE**

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***Fernando Hernandez** is the subsea technical advisor at Reaching Ultra. Hernandez speakings three languages and has extensive field experience in the ROV tooling, automated controls, subsea and well intervention sectors.*

Call for more developed ROV classification system

As ROVs are given tasks in more and more challenging environments, there has been a call for the industry to develop a classification system. Meg Chesshyre reports.

A call for the International Marine Contractors Association (IMCA) to help set up a round table to develop a classification system for work-class remotely operated vehicles (ROVs) was made in a paper at the association's recent annual seminar in London.

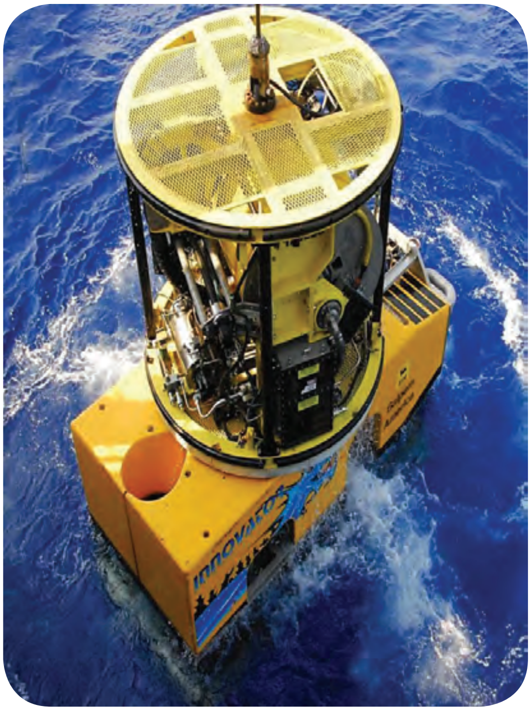
The paper, presented by Saipem subsea remote technology engineer Lorenzo Granelli, was co-authored by subsea remote technology project manager Giovanni Massari. Both authors are involved in the project engineering and production of new ROVs for Sonsub/Saipem.

Granelli says a classification system is needed for ROVs, just as there is for vessels. "If you ask for a crane vessel you have a clear idea of what you are asking for. If you ask for a work-class ROV, no one states what it is," he says.

Granelli sees IMCA as potentially the missing link between two engineering worlds, the engineering and manufacture of ROVs, and subsea project engineering, undertaken by the main contractors and the major oil companies.

He says ROV manufacturers need input to steer their research and development programs in the right direction, and a clear vision of the technical specification of ROVs. The project engineers also need to know what an ROV can or cannot do so they can plan their operations in the most effective way. It was also suggested that input from Xmas tree manufacturers might be included in the round table.

Granelli says there is also a need to define a way marine contractors can efficiently drive new developments on the basis of real needs, with the identification of standard requirements for current and foreseeable jobs in terms of ROVs, interfaces and tools. It is important to define a way in which new technology can be validated so that only well proven solutions are adopted, and to identify procedures and best practice to test ROVs or technical solutions against requirements, he says. There is also a need to redefine classification for new ROVs with a clear idea of performance.



Saipem's Innovator ROV. Image from Saipem.

ROV technology has reached an early maturity phase. While ROV functionalities are well defined, there is still considerable room for improvement, Granelli says. Main ROV manufacturers assert ROV technology is comparable with the automotive market at the beginning of the 1970s, he says. There is also a need to improve ROV operability, to guarantee highly reliable systems with a reduced maintenance cost and optimized availability. For optimal ROV operation, ROV crew capability is also a key factor for the success of an intervention.

As subsea construction programs go deeper and get more complex, in harsher environments, the demands on ROVs will continue to increase. Workclass ROV technology development will be driven by those factors that will directly impact on the capability to win contracts for state of the art subsea projects, Granelli says, in new operating environments such as the Arctic, or in areas of poor visibility and ecologically sensitive environments.

New operative tasks will include permanent inspection, maintenance and repair of subsea fields, or remote intervention by means of subsea resident vehicles, emergency intervention, touchdown point monitoring for deep water S-lay projects. The development of so-called subsea factories will lead to new construction, maintenance and inspection needs, Granelli continues. More automated or independent/semi-independent tasks are also emerging.

There are a number of different classifications and standards in existence covering ROVs, for example, DNV-GL i-5-3, ISO 13628-8, Norsok U-102-2, API 17H, IMCA r004, ABS osv-5, but on the whole they are very general. There are no specific requirements for maximum dimensions for specific operating scenarios and tasks, or for continuous dive time capability for specific operating scenarios and tasks, of particular relevance for operations in the Arctic, where access may be limited, guidelines are needed for validation of new features, tools and technical solutions, Granelli and Massari say. Environmental operability limits are needed in terms of temperature and significant wave height. OE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Reel-lay gets real attention

The race has been on to create a mechanically-lined pipe that can be installed using reel-lay. Now it's been done, and the method is taking off. Elaine Maslin provides an overview.

An increasing amount of corrosive substances are flowing through today's subsea oil and gas pipelines, generating greater demand for corrosion-resistant materials.

To overcome the corrosion caused by such substances, corrosion resistant alloy (CRA) pipes (e.g. 316L, 904L, 825, or 625), metallurgically bonded clad pipes and mechanically lined pipes have been developed.

Subsea pipeline installation firms have been paying particular attention to how to manufacture, handle and install mechanically lined pipe by reel-lay – a method which would speed up installation times, as well as reduce materials costs. Installation by reel lay also enables contractors to lay longer sections of pipe, without having to weld large numbers of stands while offshore.

Mechanically lined pipe uses a combination of carbon steel outer pipe with a corrosion resistant alloy liner. The CRA liner is hydraulically assembled inside the carbon steel pipe, creating an interference stress between the carbon steel host pipe and the CRA pipe.

According to German pipe manufacturer BUTTING, which produces BuBi-Pipe, its own-brand mechanically lined pipe, the benefits of mechanically lined pipe over clad pipe is a 40-60% reduction in cost, depending on diameter and grade.

BUTTING's BuBi-Pipe is a bimetallic pipe, which is telescopically aligned inside a pipe in carbon-manganese material and the tight mechanical bond between the pipes is achieved in a hydroforming facility.

BUTTING has been producing its own-brand BuBi-Pipe since June 1994, including for offshore use, as pipelines, riser pipes and SCR-pipes. But, until its use on the Guará-Lula NE project, by Subsea 7, offshore Brazil, in 2013, no one had deployed mechanically lined pipe – either from BUTTING or anywhere else – by reel lay, largely due to some of the issues around internal buckling of the liner during the laying process.

"Most projects have been installed by S-Lay, followed by Bundle," says Brigitte Blechinger, Senior Sales Manager Oil & Gas at BUTTING. "Reeling seems to be coming up as a new method, as it is a cost effective solution compared to the others. Further, a shorter installation period is required and the majority of welding and inspection can be done onshore. Vessels are flexible and they can quickly be mobilized to global locations. In the end reeling has a positive cost and time impact on offshore development projects."

Reels can be loaded at a spoolbase, where the pipe is spooled onto reels on the vessel, or, as with EMAS AMC's *Lewek Constellation*, they can be taken on the reel to the pipelay vessel on a barge and be lifted in to place, replacing empty spools, without the vessel having to return to a spoolbase.

According to Brigitte Blechinger, manufacturing output of BUTTING's BuBi-Pipe is also 3-4 times higher than output for clad pipes, further speeding up the process – BUTTING can produce a lot more BuBi-Pipes within a certain time frame

BUTTING's own-brand BuBi-Pipe in manufacturing. Photos from Butting.

than e. g. metallurgically clad pipes.

"The manufacturing process used is economically superior and strictest tolerances can be gained, using specialized production for both carbon steel and CRA material," Blechinger says. "In addition, variable combinations of materials can be used, freeing the manufacturer from as many raw material supply constraints."

The move to develop mechanically lined pipe for reel-lay began in the late 2000s, led by Subsea 7 and Technip.

BUTTING has been working with Subsea 7 to qualify its BuBi-Pipe for flowlines and low-fatigue riser applications by reel lay and since 2008 exclusively on BuBi-Pipe with 3mm liner. BuBi-Pipe ranges from 4in to 28in. outside diameter and up to 24m-long, produced in accordance with API, ASTM, DNV or ISO and suitable for S-Lay, J-Lay, bundle or reel-lay.

Subsea 7 was the first to install mechanically lined pipe by reel-lay on Petrobras' pre-salt Guará-Lula NE project in Brazil's Santos Basin, using the *Seven Oceans* pipelay vessel. Some 70km of BuBi-Pipe SCRs were installed by reel-lay in 2100m water depth. Subsea 7 is already also lining up its next job, on Statoil's Aasta Hansteen development offshore Norway for which BUTTING has already delivered the BuBi-Pipe. For the development in the Norwegian Sea about 19km of 12in BuBi-Pipe will be installed by reel-lay.

Subsea 7 says the main challenge associated with BuBi-Pipe by reeling was to demonstrate that the inner pipe, or liner, did not suffer from local buckling during the spooling process. "Equally important was to demonstrate the integrity of the weld joining the liner pipe to the outer pipe at the ends of each joint or seal weld," said Subsea 7 last year [2014].

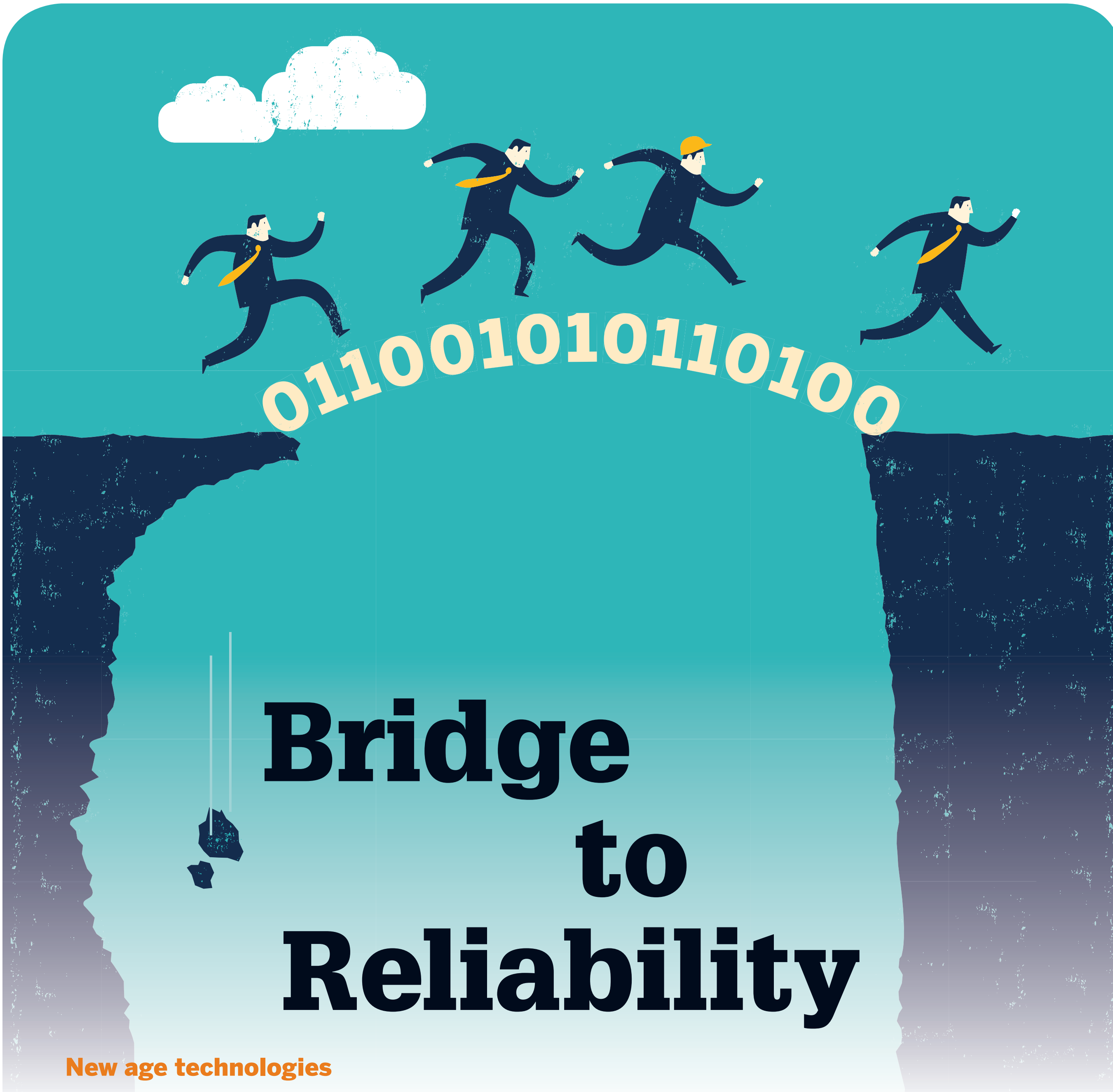
Technip's first reel lay with mechanically lined pipe is due to be on Deep Gulf Energy's Kodiak project in the Gulf of Mexico. The job is also BUTTING's next BuBi-Pipe project for reel lay, under a contract with Tenaris. Technip is the installation contractor with installation expected in 2015.

Kodiak is in Mississippi Canyon Blocks 727 and 771, in the Gulf of Mexico, in 1472-1710m water depth. The project is a subsea tieback to the Devils Tower Truss Spar in Mississippi Canyon Block 773. To withstand Kodiak field's high-temperature and pressure, as well as extremely corrosive production fluids, mechanically lined pipe was chosen. It will be installed using the *Deep Blue* deepwater pipelay and subsea construction vessel.

"Generally, BuBi-Pipes are qualified for reeling by DNV GL and other accreditation societies and in case of e. g. Guará-Lula by our customers Subsea 7 and Petrobras," Blechinger said. Subsea 7 is also further developing the uses for BuBi pipe, specifically around its potential to be used for fatigue-sensitive applications, such as steel catenary risers.

With an order backlog for BuBi-Pipe for reel lay in place, BUTTING says demand for the pipe is growing. "Currently a lot of projects are tendering mechanically lined pipes where installation shall be made by reeling," Blechinger says.

Technip, which installed the first reeled steel catenary riser in 2001, has said its design, endorsed by DNV in 2011, allows reel-lay at atmospheric pressure. Technip also had a fitness for service certificate from DNV in August 2012 for a dynamic mechanically lined SCR for reel-lay. OE



Bridge to Reliability

New age technologies block failures, and boost bottom line. Gregory Hale reports.

Every minute counts these days. The right decisions hinge on responding to issues before they become big, costly problems. The idea of equipment reliability is becoming an even more vital factor offshore.

This is why Shell created a team of engineers at its Upstream Americas deepwater headquarters in New Orleans overseeing 300 wells and about 12-13 main platforms in the Gulf of Mexico. They act as a bridge between platform operators running equipment and problem-solving engineers working on specific fixes and projects. The goal is to catch and fix small issues and alert those on the platform when they first crop up as a seemingly innocent bit of data before they become an issue.

"They are monitoring the rotating equipment and also some of their process equipment and looking for various leading indicators of degradation of equipment health," said Bart Winters, product director for asset management solutions at Honeywell Process Solutions (HPS).

"They are seeing significant savings by being able to set up monitoring systems, like in the case of turbine exhaust gas temperature, that look for a sudden rate of change in the exhaust gas temperature. They will look at the last month average and compare that to the last 15min average and if they see a spike or a sudden change, that will trigger a surveillance task and a group of engineers comes in and investigates what might be causing that sudden change. Preventing a catastrophic compressor failure is worth about $4 million to them. In another case if they trip a compressor and have an event flaring for a four-hour period in downtime, it can save them multiple millions of dollars."

Tom Moroney, manager of deepwater technology and geosciences at Shell spoke at the Honeywell User Group in June 2013 about the hike in technical and business complexity along with the workforce demographics and techniques on utilizing the resources they had to the optimum potential. That is where Shell's Bridge team comes into play, so they can use automation technology to fix the small problems.

The use of the reliability technology helps alleviate the problems that operators have learned the hard way.

The new technology allows them to configure their systems to understand where past problems cropped up. "They are continually adding additional rules and algorithms to monitor and look for different kinds of or new conditions," Winters said.

Remote reliability

Monitoring systems is not just a one person proposition, and as Shell determined, it takes a large cast. That is why remote monitoring is playing a bigger part in the reliability picture moving forward.

"We are doing two deployments in the North Sea and both of those are moving to a remote operations scenario," Winters said. "Their goal is to reduce the amount of bodies on the platform, one of the implications is they will have fewer maintenance people on the platform. When they are sending someone to the platform they can know which potential instruments are having problems, and what pumps are having problems, they can be more proactive around that and do better maintenance scheduling. Technology is bringing in health information from the smart instruments, electrical systems, rotating equipment, and choke valves. That is one way to be more proactive around optimizing the wrench time when going out to the platform."

The whole idea behind remote monitoring of equipment on the platform is to head off any issues for the critical assets.

"What you are able to see is a rate of degradation on any of the equipment on what you characterized as the failure modes and how you have characterized the degradation mechanisms," said Stan Grabill, principal reliability consultant at HPS. "So, it is not just seeing it hours before it fails, but rather getting early indications or early event detection. In some cases we can have an intervention without severe degradation or can recover the degradation with some proactive maintenance. You can accumulate this information across an array of assets whether they are electrical rotating machinery, heat exchanger performance, where you get input on performance you can see anything that is starting to go south on you. The software is set up where you can see the degree of severity and the degree of degradation as well."

Reliability trend

Right now, equipment ends up instrumented for two things: safety, where it connects to shutdown systems, and for

"The whole idea behind remote monitoring is to head off any issues for the critical assets"

control. There is significant amount of instrumentation already on the equipment, but one trend is seeing additional instrumentation for maintenance and reliability.

"The challenge is how do you pull all that disparate data as it relates to the performance and health on a piece of equipment and translate it to what the real-time health indicator is for that piece of equipment," Winters asked.

"You need a central repository and a focal point for bringing that data in to assess the overall equipment health," he said. "In the past you would have a vibration monitoring system that was separate from performance monitoring, which was separate from the control system. If you had high vibration, the vibration tech would not know what the compressor or pump was doing at the time of high vibration. Having it all together in one place you can see that yes, I have high vibration but I was running the unit hard so I can understand, or we had low flow, which means I had a cavitation issue."

Program fundamentals

It is fundamental to have a methodology to determine criticality of equipment and your system in order to have a good reliability program.

"Regardless of the asset, whether it is instrumentation, process equipment and rotating machinery, there needs to be a way to determine criticality," Grabill said. "Criticality sets up the priority in which you going to put together your reliability strategies. Criticality can come in different ways, there is a structured way of doing that by virtue of understanding the influence of each asset on safety, environment, production, volume, cost to maintain, and yields. There are a number of factors that can place in the criticality equation with the number of influences it has on the business and safety. The second thing is to take the criticality and figure out what to do with it." That is where the user understands the failure mode.

The next move is to figure out what equipment to build the reliability strategy around. "I will build these strategies from maintenance analysis, root cause from past failures, and from just common sense," Grabill said. "Once you understand the failure modes, you ask if you can afford to put the mitigation strategies in place, like real time condition monitoring, preventive maintenance schedules, operator monitoring. There is a cost benefit to each one of those depending on the impact of the failure modes to the business and the longevity of the equipment. Once I have the failure modes identified and the strategy built I have to implement the strategy, which can be complex. What you are doing is transferring the failure modes into actions.

"Get the work process around to take the failure modes with the criticality and the degradation signals and put them in where we can build some intelligence and experience into the system, then we can send a signal to the operations, reliability and maintenance guys to say I have critical equipment up there, but what is the most critical impending degradation taking place that I need to pay attention to today, or the next week? That intelligence needs to be built into this whole work process."

Understanding the reliability equation that allows equipment to communicate the nuances of the dynamic offshore environment means engineers can make decisions before small problems escalate. **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.*

Middle Eastern promise

The shallow waters of the Arabian Gulf belie the plethora of offshore infrastructure – new and old – in the Middle East. Elaine Maslin probes beneath the waves.

Despite its immense resources, the Middle East has often been missed off the maps of offshore oil and gas firms. Yet, this region has one of the highest clusters of offshore platforms globally.

While they're mostly in less than 70m deep water, those operating them face many of the same challenges experienced in other parts of the world – their assets, both the platforms and pipelines, and reservoirs, are aging, which requires enhanced oil recovery expertise, as well as inspection repair and maintenance and asset integrity specialists.

The amount of infrastructure in the Arabian Gulf is also increasing. According to data from Infield Systems, some 126 new platforms were either installed or are due to be installed in 2010- 2015 offshore the United Arab Emirates (UAE), Iran, Qatar, and Saudi Arabia.

The plethora of facilities are there for a big reason. Just over half of the world's proven conventional oil reserves and 42% of the world's proven conventional gas reserves are in the Middle East and North Africa (MENA). The region has 13 of the world's 20 giant oilfields as well as the largest gas field in the world – South Pars, shared between Iran and Qatar.

Many were discovered in the 1960s, shortly after offshore exploration started, such as Upper Zakum (1964, United Arab Emirates) and Zuluf (1965, Saudi Arabia) and they continue to produce on a prolific scale, prompting continued expansion, such as at the Al Shaheen field, discovered offshore Qatar in 1974 and South Pars (known as the North Field offshore Qatar).

The fields are big, and so is the extent of the facilities that produce them. According to a Scottish Enterprise report, there were some 750 offshore fixed platforms in the Middle East at the end of 2012.

But, many of them are aging. Some 450 of the 750 are off the United Arab Emirates and more than 70% of these are 25+ years old, with some beyond 40 years, says Anupam Ghosal, DNV GL services line area manager for verification in the Middle East and India.

This alone means there is a significant amount of work to do. Abu Dhabi Marine Operating Co. (ADMA-OPCO) has launched various life extension projects and plans to upgrade and replace all its aging pipeline networks by 2030, for example, DNV GL says.

Aging assets attracted FoundOcean to the region. The company opened an office in Dubai in early 2014, offering strengthening, modification and repair work, using grouting and fabric formworks out of Sharjah, and will be looking to expand into Saudi Arabia and Qatar.


Martin Grant

Naval Sundhu, associate director, FoundOcean, says: "The Middle East has lots of structures getting close or well beyond their original design life, so there is a lot of demand for ensuring structural integrity and for the pipelines that start to suffer from free span movement."

Martin Grant, CEO of Energy at UK-based engineering and project management firm Atkins says: "We are finding there is a focus

In 2005, Maersk Oil Qatar approved a field development plan for a major expansion of the Al Shaheen field infrastructure, with 15 new process and wellhead platforms. Photo from Maersk Oil.

on asset management strengthening. ADNOC more and more are using us to do finite element analysis on aging assets. Assets are getting older, most were designed for a 20-25-year life and most are now required to operate beyond that. Oil is more valuable than it has been and although it is near to $80/bbl, this historically is still a high number. Underpinning all of that, without a doubt the industry worries more about facilities than ever before, particularly as they are pushing the envelope. The challenge in the Middle East is that there is a huge number of structures. Because the water depth is shallow very often fields are exploited using multiple small platforms, so there is a lot of steel in the water."

Another challenge for the region is the scale of the reservoirs and in managing hydrocarbon processing through the life of the fields, including dealing with larger amounts of produced water and sour production.

As well as maintaining assets, a large focus is on pushing up recovery rates at these existing giant fields. Total, which is the only international oil company to operate a field in Abu Dhabi, in partnership with Japan's Inpex, has been "pushing recovery to the limits" at the Abu Al Bukhoosh field using advanced seismic and enhanced oil recovery (EOR) technologies.

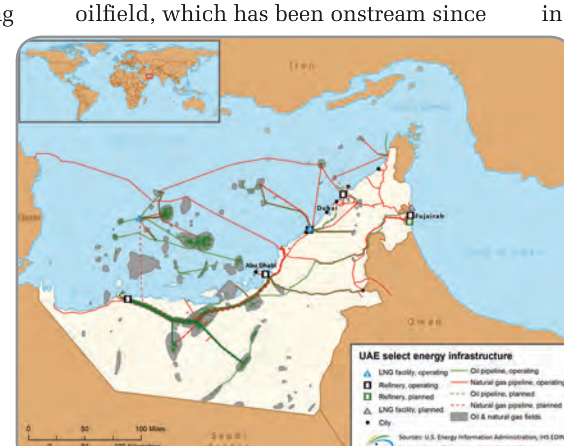
UAE production amounted to 10% of Total's total production in 2012. Abu Al Bukhoosh, which extends over 20sq km, was discovered in 1969 and production started in 1974. In total, the field now has 116 wells, 23 platforms, 29 subsea lines, and seven subsea wells and recovery rates have reached 55%, through advanced seismic and enhanced oil recovery techniques, including gas lift, from 1981, and gas injection, from 1991, to aid reservoir understanding.

Technologies such as electrical submersible pumps (ESP) are key for some offshore fields, such as Abu Dhabi Oil Co.'s Mubarraz concession. The first was installed on the concession in 1975. By September 2014, 45 producers on the concession contain ESPs.

Operators, including international firms such as BP and Statoil, have been discussing how CO_2 could be used for EOR in the Middle East, to reduce natural gas use for injection but also deal with CO_2. During the Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Masdar and ADNOC announced Al Reyadah, the Middle East's first company focused on exploring and developing commercial scale projects for carbon capture, use and sequestration. Japan's JOGMEC is also carrying out research and development with ADNOC on CO_2 for EOR.

Operators are also spending cash extending and redeveloping fields. In 2005, Maersk Oil agreed a plan to expand the Al Shaheen field, offshore Qatar, with a further 15 new platforms and 160 production and water injection wells. By 2012, Al Shaheen totaled 35 platforms and produced around 40% of Qatar's oil and gas output.

Last year, Qatar Petroleum announced it was going to invest some US$11 billion redeveloping the offshore Bul Hanine oilfield, which has been onstream since 1972, by drilling 150 wells by 2028 to double production.



The United Arab Emirates and key infrastructure.
Image from the US Energy Information Administration.

Zadco, a partnership between ADNOC, ExxonMobil, and JADCO, is currently expanding the Zakum field, with for four new artificial islands and additional satellite platforms. The offshore facilities are due to complete in 2015, with the islands completing next. Upper Zakum sits 84km northwest of Abu Dhabi. It already comprises some 90 platforms, including an accommodation platform able to house 550 people. Zadco says Zakum, is the second largest oil field in the Arabian Gulf, containing some 50 billion bo.

Scottish Enterprise's report says, overall in the Middle East, in 2012-17, some 92 new installations are expected to be installed offshore the UAE, 56 offshore Iran and 48 offshore Saudi Arabia, taking the total in the MENA region from 1807 at the end of 2012 to nearly 1994 by the end of 2017.

Fixed structures (including piled platforms, gravel islands, caisson platforms, jackups and gravity-based structures) will likely account for most of the new facilities, having represented some 96% of offshore platform spend over the 2008-2012 period.

But, the focus is not just on existing fields. ADNOC has said it is planning to increase production capacity to 3.5MM b/d by 2018. ADMA-OPCO, ADNOC's offshore arm, is expected to contribute about half of this, from existing fields, but also from new fields, including Umm Lulu and Nasr. ADMA-OPCO recently agreed three contract packages for Nasr, with NPCC, Hyundai Heavy Industries and Technip. The project will include seven new wellhead towers, and 110km infield pipelines.

Umm Lulu project, due to be complete in 2018, will comprise six well head towers and six other new platforms, as well as infield pipelines and cables. National Petroleum Construction Co. has the EPC contract for the project, part in partnership with Technip.

Qatar is working on the North Field Barzan Project, which includes on and offshore facilities. Qatar Petroleum is also assessing its 2013 Khuff discovery, the first new gas discovery offshore Qatar in more than 40 years in exploration Block 4 North. Further exploration is ongoing.

Meanwhile other countries are

The Abu Al Bukhoosh central facility, operated by Total, offshore Abu Dhabi. Photo from Total.

Zadco's Zakum supercomplex, offshore Abu Dhabi.
Photo from Tony Cavill.

looking to build offshore positions. Oman, which has little offshore production to date, has said it is looking to increase exploration off its waters. Kuwait, which has no offshore production, recently completed 2D and 3D seismic in its offshore area.

Deepwater activity is starting to take hold, with Saudi Aramco in the early stages of deepwater exploration in the Saudi Arabian Red Sea.

Steve Molloy, Aquaterra Energy's Middle East and North Africa region manager, sees a potential for the UK-based engineering company's minimum facilities and conductor supported platform designs in the region – including Iran, when sanctions ease to the degree that western firms are able to once again operate in the country.

"Even with the existing facilities, there are opportunities for minimum facilities platforms, providing a low cost solution," Molloy says, and a potential alternative to the artificial islands built in some areas. "There are a number of conductor supported platforms already installed, offshore Qatar and UAE. Saudi Arabia is the next step. It is also quite exciting to see the opportunities that might come out of Iran."

Driving some of the offshore development is the strong growth in natural gas demand. While the Arabian Gulf has an abundance of natural gas reserves – Iran has the second largest gas reserves in the world – only Qatar is a significant exporter.

Nick Dalgarno

Saudi Aramco's Karan offshore gas project – the company's first offshore gas find – reached planned capacity in 2012, after coming onstream earlier in the year, and production start-up was expected from the Arabiyah and Hasbah offshore gas fields, which are part of the Al Wasit Gas Program, and comprise 15 offshore platforms, in 2014. Together, the Al Wasit fields and Karan are expected to increase Saudi Aramco's output by 40% – most of the gas will be for local power and industrial feedstock.

The growth, in brownfield and greenfield, will make the Middle East one of the key markets for oilfield services companies for decades to come, says Nick Dalgarno, co-head of eastern hemisphere corporate finance at Simmons & Co. International.

Dalgarno says there is an increasing willingness amongst governments and the national oil companies to build relationships with foreign firms to bring know-how and technology into the region, due to an increasing need for enhanced oil recovery, as well as sour gas, heavy oil, tight gas, LNG, GTL, "clean fuels" refineries, carbon capture and storage, nuclear and solar technologies.

"No oilfield services company can afford to ignore the market in the Middle East due to its sheer scale and variety," he says. "The region is increasingly receptive to bringing in skills and technology from outside to support its exploration and production activity and EOR requirements and indigenous businesses are also seeking opportunities to grow internationally." OE

Leviathan looms

The Tamar field, which was turned around from discovery into production in only four years. Beagelman points to this as proof positive that Israel has the proper infrastructure in place to support its growing offshore sector.
Photo from Albatross Aerial Photography Ltd.

Sarah Parker Musarra examines Israel's Leviathan field's potential and separates fact from misconception.

When the first gas discoveries were made offshore Israel in 1999-2000, Israel was thrown into the international energy spotlight.

Initial offshore oil and gas discoveries were Noa in 1999 and Mari-B, in 2000. Operator Noble Energy announced first gas from Mari-B, the larger of the two fields, on Christmas Eve 2003. But, more was to come. The 1 Tcf (gross reserves) Mari-B field gave way to the 10 Tcf (gross reserves) Tamar field, which was touted as the largest deepwater natural gas discovery in the world, at the time in 2009. Just four years later, Tamar was onstream.

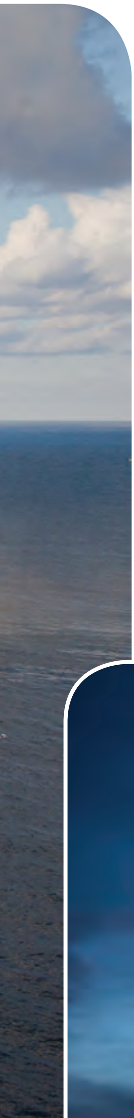
The pace – and scale – did not slow. In 2010, less than 30mi from Mari-B, Noble Energy found the Leviathan field, dwarfing Tamar with an estimated 22 Tcf gross mean natural gas resources – the largest discovery in Noble's history.

All four finds are in the Levant basin, which is estimated by the US Geological Survey's (USGS) 2010 report to have about 1.7 billion bo undiscovered recoverable and about 122 Tcf of undiscovered gas. Noble expects Leviathan's Phase 1 to be ready for production by 2018.

In December 2013, Noble Energy announced that it encountered approximately 355ft of net natural gas pay in the Tamar SW well, 8mi southwest of the Tamar field, in 5400ft water depth, marking its eighth consecutive discovery in the Levant Basin.

"Due to lack of information, there is not enough focus on the further opportunities offshore in Israel. The industry recognizes now the huge discoveries and production levels, however, there is not enough knowledge about the further exploration opportunities in Israel's offshore deepwater. The geology spells it out," says Joshua Beagelman, COO of Universal Oil and Gas (UOG), the organization which brought Israel its first international oil and gas conference in 2014. "There will be more natural gas discoveries in Israel and oil discoveries–it just depends who will take the leap."

Catarina Podevyn, content analyst for Infield Systems, said that Israel is driving offshore spend in the region, holding a 25% share of the central Mediterranean's forecast offshore capex



throughout 2015-2019. Noble Energy alone is predicted to pump an 84% share of forecast capex off Israel during the same period.

"There should be a queue of operators focused on Israel," Beagelman says. "Especially when you look to Cyprus, who [has] not produced anything as of yet, and you have three major operators exploring in their waters."

Like many developing regions, the Israeli offshore sector has had its share of naysayers and even doomsayers, particularly when it comes to bringing Leviathan online. The general political unrest in the region might contribute to some general unease among investors; that certainly seemed the case when the Financial Times and others reported on tumbling economic activity within the country, as the conflict with Hamas in the Gaza Strip continued.

Security concerns are high on the agenda, but can be a misconception, Beagelman says. Professor Brenda Shaffer, an expert in international energy, based at Georgetown University, says Israel handles security of energy infrastructure differently than other countries. "In contrast to places where the companies take on the security [of the assets], in Israel, the government, through the Navy, has taken on most of the security concerns," she says. "I don't really think that's really a factor."

"In terms of its assets, Israel has a long history of protecting its assets very successfully," Beagelman says. "If you compare Israel to its current competitors (other emerging oil markets), there is no comparison – Israel is already deploying 'iron dome' technology for its naval ships and is one of the safest places to be offshore."

Still, the Leviathan development is going ahead. Podevyn says that much of Noble Energy's Israeli capex is earmarked for Leviathan, which is itself expected to amount to 69% of Israel's offshore capital expenditure in 2015-19, with peak spending in 2019.

Leviathan, which received its name from a giant sea monster in the Bible's Old Testament, is in the Mediterranean Sea, about 130km from Israel's coastline, in about 1600m water depth. It is one of the largest offshore discoveries in the past decade.

The deck of the Tamar platform, shown in 2012, while under construction.
Photo from Noble Energy.

The field's consortium submitted what Reuters reported to be a US$6.5 billion initial development plan for Phase 1 of the field to the country's Ministry of National Infrastructures, Energy and Water Resources in 2014. Phase 1, expected by Noble and partners to start up in late 2017/early 2018, will include an FPSO with a capacity of 1.6Bcf/d, which BW Offshore announced that it was in FEED to provide.

Phase 2 expansion options being assessed include regional pipeline sales, FLNG, and Cyprus onshore LNG options, according to Noble in a late 2014 presentation at the Johnson Rice Energy Conference.

One question mark about the project is its ability to become a major export project and, if so, to where, says Shaffer. "It's still a big field by itself, but in terms of how much gas is available for export, there's maybe 250-300 Bcm available for export. That's not a game-changer for Europe, for Asia," she says.

Shaffer says that the size of Leviathan's resources, the amount of infrastructure, and the market needs within the area bordering Israel are a perfect match. She does not see Europe or Asia as likely export markets, despite an Israeli vision to export to Europe via a new pipeline. She points out that globally expensive gas exports are facing current market pressure.

Keith Elliott, Noble Energy's Senior Vice President, Eastern Mediterranean Natural, shared a similar perspective with OE, saying: "Gas from these developments [Tamar and the first phase of Leviathan] could add tremendous economic value to Israel and other countries in the region in the form of revenues, fuel costs savings and enhanced environmental quality."

The Leviathan consortium currently has two letters of intent (LOI) in pace: One signed in June to export up to 3.75 Tcf of natural gas over a 15-year period to the UK major BG Group's LNG plant in Idku, Egypt, and a September US$15 billion preliminary deal to supply a base gross quantity of 1.6 Tcf of natural gas over a 15-year term with Jordan's National Electric Power Co. (NEPCO).

"We now have over 60% of Leviathan's initial capacity and 80% of targeted initial sales volumes secured," Elliot said in a statement announcing the NEPCO LOI. In Noble Energy's November 2014 Investor's Information, the company said that it was negotiating towards final agreements, and that it remained focused on "domestic and regional customers."

Noble Energy operates Leviathan with a 39.66% stake. Its partners include Delek Drilling (22.67%), Avner Oil Exploration (22.67%), and Ratio Oil Exploration (1992) Ltd. Partnership (15%). OE

Solutions

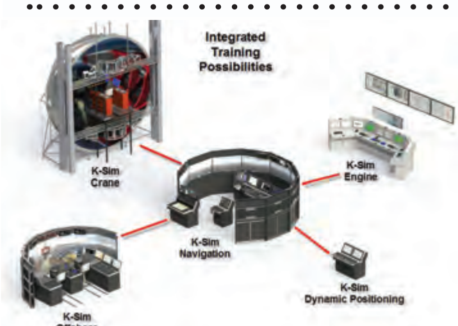
Schlumberger introduces StingBlade

Smith Bits, a Schlumberger company, introduced StingBlade, a conical diamond element bit.

StingBlade bits use Stinger conical diamond elements optimally placed across the bit face which induces high point loading on the formation. In directional applications, the new drill bits cut with lower torque than conventional cylindrical cutters and achieve higher build rates with less toolface variation.

StingBlade bits have been successfully tested in more than 300 wells worldwide, both onshore and offshore, in conventional and unconventional applications in North, Central and South America, the North Sea and Europe, Africa, the Middle East, Russia, Southeast Asia and Australia. To date, more than 686,000ft have been drilled worldwide.

In a field trial conducted in the offshore Browse basin in Australia, a customer used a StingBlade bit to drill a 12 ¼-in. vertical section through a formation known to cause premature impact damage to conventional PDC bits. The drill bit increased interval length by 97% and ROP by 57%, saving the customer more than five days of drilling time. www.slb.com



Kongsberg unveils new simulator

Kongsberg Maritime unveiled its new ship's bridge simulator, K-Sim Navigation, approved to DNV GL Class-A standards. Designed for the future of advanced and integrated simulation training, the simulator meets the requirements of the most demanding navigation training for merchant, offshore and naval vessels.

K-Sim Navigation features an advanced physical engine, hydrodynamic modeling, and new visual system, allowing vessels, objects and equipment to behave and interact as in real life.

Features also include educational tools utilizing a modified ECDIS chart as a starting point with drag & drop function for creating exercises. The instructor system also allows automatic recording and an advanced assessment system for ensuring optimal training and feedback standards.

K-Sim Navigation's flexibility extends to hardware, with a fully scalable range of options available – from a PC-based desktop system, through to a full mission bridge simulator. The system, built on the same core technology platform as the market leading K-Sim Offshore simulator, can easily be integrated with other Kongsberg Maritime simulators (including crane, offshore, engine, cargo, ballast and DP) to enable a comprehensive range of training scenarios. www.kongsberg.com

Tercel releases premium roller cone bits at ADIPEC

Tercel Oilfield Products released its new premium series Roller Cone Drill Bits at the Abu Dhabi International Petroleum Exhibition and Conference in Abu Dhabi, UAE. The new line, Tercel says, features precision machined bearing races that are matched to provide extended operations, higher revolutions per minute and heavy weight on bit.

The seal system is designed to provide optimal configuration and includes an extreme pressure synthetic lubricant that extends the bearing life. A tungsten carbide hard facing is applied to all surfaces of the steel tooth cutting structure as well as on the shirttail tip and leading edge on all tungsten carbide insert and steel tooth premium bits to provide extra protection in challenging formations. Additionally, flat top TCIs are pressed into the gauge surface of each steel tooth cone.
www.terceloilfield.com

Claxton develops new CCSS

Claxton Engineering Services has developed a new conductor cementing support system (CCSS).

The Claxton CCSS secures the conductor with a hydraulic jack-and-clamp mechanism that holds the weight of the conductor while the cement cures. This means that the rig no longer has to hold each conductor, and can therefore move to the next slot and begin running another conductor, typically saving 12 - 18 hours of rig time per conductor, according to the company.

"The new system has a compact design and can be repositioned easily without a crane," says Dannie Claxton, Claxton technical director. "In addition, it offers schedule flexibility because it splits in half, thereby enabling operators to run the conductor before, or after, the CCSS is in place.

Claxton says its CCSS has already been used successfully in the field on projects for two major North Sea operators.
www.claxtonengineering.com

Activity

Stork Technical Services opens Houston tech center

Stork Technical Services christened its new Houston Technology Center with a ribbon cutting ceremony on 3 December. The facility houses the company's supply chain and logistics departments.

On hand to cut the ribbon was Senior Vice President of the Americas Jorge Estrada. Also in attendance was Operations Manager Richard Tang. During a speech, Estrada said the company is partnering with Houston Community College to ensure employees that oversee project management are PMI certified.

The new location is equipped with a training facility, which includes rope access, as well as office space devoted to both Stork's engineering and asset integrity management services. On hand for the grand opening was Project Manager Levi Vaverka, who helped demonstrate some of Stork's innovative corrosion detection and mapping solutions.

Tang said the new location, which consolidates operations in Sugar Land, Texas, and in Lafayette, Louisiana, made sense in order to better serve Stork's clients located in Houston's Energy Corridor. ■ –*Audrey Leon*

Stork Technical Services' employees celebrate the new Houston center.

Lubrizol to buy Weatherford units

Berkshire Hathaway's Lubrizol Corp. agreed to purchase Weatherford's engineered chemistry and integrity drilling fluids business for US$750 million in cash plus a potential increase of $75 million for an earnout that is tied to the post-closing performance of the businesses.

The sale is expected to close before year-end 2014. Weatherford says proceeds from the sale will be used to pay down debt.

"The agreement is another step in Weatherford's previously announced plans to divest the company's non-core businesses. This transaction brings our realized cash divestiture proceeds to approximately $1.8 billion during 2014 and implies that our net debt will range between $6.6 billion to $6.8 billion at year end 2014," says Bernard J. Duroc-Danner, Weatherford chairman, president and chief executive officer.

Fugro to remain independent

Fugro reaffirms the company's intent to stay independent following Royal Boskalis Westminster's acquisition of 14.8% stake in the company. However, Fugro said it does intend to explore possible partnerships with other companies regarding its subsea division, including with Boskalis.

"The objective of such a partnership is to build a global Inspection, repair, replace and maintenance market leader," Fugro added.

The acquisition was seen as a move toward a possible takeover of Fugro by Boskalis, despite a statement by Boskalis CEO Peter Berdowski saying that the marine services provider does not intend to make an offer on Fugro.

GE opens Brazilian subsea research center

GE opened its US$500 million Brazil Technology Center in Rio de Janeiro, focusing on developing advanced technologies for offshore oil and gas exploration and production. They will work with Petrobras, Statoil, BG Group and other GE customers in the region on solving engineering challenges such as drilling 40,000ft deep wells 100mi offshore, and processing hydrocarbons 10,000ft below sea level. GE is already working with Petrobras and BG Group on research projects to develop the technologies and equipment that will be required to move production from floating platforms to the seabed.

In 2008, GE and Statoil established a formal technology cooperation agreement on subsea technology development. In 2009, Statoil decided to start R&D in Brazil, focusing on research in improved oil recovery, CO_2, carbonate reservoirs, and subsea technologies.

Paine Electronics joins Emerson Process Management

Paine Electronics will become part of Emerson Process Management following Emerson acquisition from Paine Electronics, LLC. Terms of the acquisition were not disclosed. With this acquisition, Emerson Process Management extends its upstream capabilities in subsea and downhole drilling operations. Paine's products will join the Rosemount portfolio of measurement technologies.

Intertek opens Abu Dhabi tech center

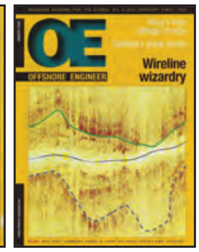
Intertek has invested US$2.8 million in its new Abu Dhabi Technology Center, which supports new exploration and existing operational activity.

The Abu Dhabi Technology Center is currently equipped to provide reservoir characterization services, including routine and special core analysis. In the near future, services will be expanded to include pressure-volume-temperature and fluid phase behavior, flow assurance, corrosion and production chemistry.

People

Spotlight

By Elaine Maslin



40 years of OE

In Spotlight, we highlight individuals who help make the offshore industry tick. This month, to mark OE's 40th anniversary, we're placing OE under the lamp.

Offshore Engineer's (*OE*) roots are in engineering. From the very beginning of the magazine, when the North Sea oil and gas offshore industry was only just emerging, OE's founders were focused on engineering.

For the industry, and anyone with an interest in it, the 1970s were a hugely exciting time. A new industry was being born on a scale bigger than anything many had seen before.

"The offshore oil and industry was in its infancy," says Alan Dawson, *OE*'s founding publisher. "There were massive float-outs from Norway. It was a new industry."

"It was a big development in civil engineering," says Alan Levett, the sales lead when *OE* launched. "It was the hot topic of civil engineering at the time. They had found all this oil in the North Sea and how were they going to get it out in this harsh environment?"

Dawson and Levett were both working for Thomas Telford, the publishing arm of the Institute of Civil Engineers, when the idea for *OE* was born. Thomas Telford had launched a new magazine, *New Civil Engineer*, in 1972, and the features it ran on the offshore industry, "went down like a bomb," Levett says, exciting the journalists who wrote them, including Adrian Cottrill. Cottrill's early identification of the industry as "one to watch" helped spur the idea for *OE*.

The very first issue of *OE* ran off the printing press in January 1975. It was founded on gut feeling, but it was an overnight success, Dawson says. "The magazine was launched on a prayer. We did not do market research and we didn't have a business plan, but we were 100% confident it would be a success." In fact, the team had to put in overtime just to get through the readership applications. "It was pretty exciting," Dawson says.

The editorial content followed the same standards as in *New Civil Engineer*, which had led a new breed of business

John Gammage poses with a photo of himself reading OE in 1976.

magazines in the UK. The first editor was Rick Wilkinson, a New Zealand-born geologist who had been working for the Oil Man, but came over to work for *OE*.

Meg Chesshyre, who has watched the industry grow and has been a long-term contributor to *OE*, says: "The North Sea oil industry in the 1970s had a predicted 10-year life span. By the early 1980s, Britain had become a net exporter of oil, and by the mid-1990s, gas. A press trip out to Shell's Brent field revealed platforms on the horizon in all directions both in the UK and Norwegian sectors. Now, Brent is being decommissioned. Over 40 years on, the focus is on maintaining the aging infrastructure originally only designed for 25 years."

While the magazine's early focus was firmly on the large structural engineering side of the business, reflecting its origins in the civil engineering business, *OE* has developed to focus on all aspects of technology and engineering in the offshore oil and gas sector, helping engineers from all disciplines learn about their own areas, but also the other disciplines.

Shaun Wymes, who started working with *OE* in 1980, saw the potential in the magazine and is now its owner, as part of the Houston-headquartered AtComedia stable. "It has been fascinating to be able to witness the technical revolution that has occurred offshore over this period of time," Wymes says. "I have always thought if you compared pictures of oil and gas trade show exhibits every five years you would have an interesting visual display of how rapid the technological advances have been. So few in the general business populace realize how sophisticated the business has become and the extent of the challenges that the oceans of the world present."

The future is looking just as interesting as the industry continues to push technological boundaries, into deeper waters, harsher environments and more complex reservoirs.

Brion Palmer, *OE*'s current publisher, and AtComedia's president, says: "It is amazing how the industry has evolved, when you consider the USA is working towards energy independence by 2018, and Mexico recently ended the Pemex monopoly. The landscape has certainly changed; the technology has definitely changed; even some of the players have changed. The one constant is that *OE* will be there to report on all the key developments, both here and on OEdigital.com." **OE**

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(check one box only)

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

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

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

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

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

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

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

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Faces of the Industry

By Kelli Lauletta

It is fitting to kick off the New Year with a profile of Statoil Vice President Helge Hove Haldorsen, who takes the reigns as the 2015 Society of Petroleum Engineers (SPE) President.

As we look at a new year with uncertainty in oil prices, Haldorsen is a personality who takes it all in stride and looks at the big picture.

Known for his insatiable drive for pushing the conversation to evolve the E&P industry, Haldorsen brings energy, intellectual muscle, humor, and enthusiasm to industry forums. He embraces the surprises, innovations and even uncertainties that are commonplace in the oil and gas industry. He is a visionary, a forward thinker and always looking to the limitless possibilities of human endeavor.

Haldorsen reveals the spark that drew him into oil and gas, gives his take on Texas "culture shock," and offers insight on the need for the "next versions" of E&P and SPE.

What sparked your interest in oil and gas?

When I was about to finish high school in Norway, huge offshore oil and gas discoveries were made in the North Sea and cool images were broadcast on Norwegian TV. We could see drilling rigs, production platforms and amazing high tech offshore equipment.

These exciting images triggered my interest in E&P, and I decided to start my petroleum engineering degree. The Norwegian authorities invested in ramping up E&P education – offering new courses in petroleum geology, exploration geophysics, petrophysics, reservoir engineering, drilling, facility and topside engineering, project management and more at universities.

Was there a key life event that changed your career course in a definite direction? If so, please describe it.

There were two important events. Professor Tony Podio, on his sabbatical leave from UT Austin, who was teaching production engineering in Norway, suggested that I come to Austin for my PhD. I did just that after a period with ExxonMobil in Norway. On 16 December 1982, I defended my dissertation in reservoir engineering with Professor Larry W. Lake as the Chairman of my PhD committee.

The second event stemmed from the advice Master of Science students received from all the professors: you must join SPE – it will make you a better professional, and it will be a 'partnership for life.' I joined SPE in 1978, 36 years ago! My professors were right, as over the years I have become a much better and more innovative engineer because of SPE.

Did you experience any culture shock when you came to the US from Norway? Did anything in Texas surprise you?

Certain things are just very different such as wearing cowboy boots with a suit, which I had never seen before, and wearing white shirts so overly starched that they make a sound when you walk. Another surprise was how Texans eat. First, you cut the food in small pieces, then you put down your knife and move the fork over to the other hand and eat the small pieces carefully, before you repeat the ritual. We just don't eat like that in Europe! In Texas, desserts like 'mud pie' – as big as building bricks – and unbelievably big steaks were clearly a new experience. Another first for me, wearing a three-piece suit in 105°F and not sweating like mad. However, people everywhere are largely the same. I found Texans and Americans to be warm, wonderful inclusive people. And you know what, life is an echo: You get back what you send out!

What do you enjoy most in working in oil and gas?

Knowing that I get up in the morning and play a small role in helping 7.2 billion people get their energy every day for lighting, transportation, heating and cooling.

Globally, every single day in 2014, we teamed up to produce about 92 MMboe/d and 325 Bcf/d of natural gas. This energy makes the world go round and lifts living standards, which gives me a huge sense of purpose. I am very proud to play a part in a business that drills approximately 83,000 wells and invests $1 trillion per year. How can you not be excited? My good friend Steve Thurston with Chevron puts it this way, "when we develop fields in ultra-deep water, it's like going the moon every day!"

I'm also drawn to the multidisciplinary nature of E&P, the risks we have to identify and mitigate, the fiercely competitive, but also the amazingly collaborative nature

Helge Hove Haldorsen *is VP Strategy & Portfolio and Mexico Country Manager for Statoil Development and Production North America in Houston. Haldorsen has an MSc in petroleum engineering from The Norwegian Institute of Technology in Trondheim and a PhD in reservoir engineering from the University of Texas at Austin. Haldorsen was a Second Lieutenant in The Royal Norwegian Navy and held various positions within reservoir engineering at Esso Exploration Norway in Stavanger, Sohio Petroleum Co. in San Francisco and Anchorage, and The British Petroleum Co. in London. Haldorsen joined Hydro in 1987 and held a number of key management positions with the company: Chief Reservoir Engineer, VP Exploration & Research and President E&P International.*

After the acquisition of the Houston-based independent 'Spinnaker' by Hydro in 2005, Haldorsen served as president until the merger with Statoil in October 2007. Haldorsen has served on the Society of Petroleum Engineer's (SPE) Board of Directors for three years and he has been an SPE Distinguished Lecturer and an SPE Distinguished Author. He has written many technical papers and articles and has been a Professor of Industrial Mathematics at the University of Oslo, as well as a lecturer at Stanford University. Haldorsen is currently a member of the Cockrell School of Engineering Advisory Board at The University of Texas at Austin, a member of the 'OTC D5: THE NEXT BIG THING' Advisory Board and a member of the SPE Boards of Directors. Haldorsen currently serves as the 2015 SPE President.

of the business, and finally, the force for good we are in the communities where we operate. Also, the industry is full of wonderful, interesting, entrepreneurial people with whom you develop long-term trusting relationships. I also enjoy the fact that everything is really uncertain: we can't really describe the subsurface sufficiently well to make accurate predictions, we don't really know the future oil and gas price, and hence, there will always be surprises – negative and positive.

As you take on your role as president of SPE, what are your 2-3 top goals?

That SPE's 124,000 members quickly have access to the latest and greatest information in their professions, especially since new technology/methodology/research and development inflection points keep reoccurring and the 'half-life' is getting shorter. SPE quickly adapts to the changing needs of its diverse membership without compromising what really sets SPE apart – quality! Another goal entails SPE stepping up to the plate to help the E&P industry quickly improve its competitiveness by becoming E&P2.0. Lastly, that SPE is very appealing to and offers a great value proposition for young professionals.

How do you see SPE engaging the next generation of oil and gas talent?

By 'listening loudly' to them. First, they learn, connect up, solve problems, and innovate differently than 55-year-olds. On the one hand, managing the 'crew change' means experienced E&P professionals mentor and pass on their wisdom to the young professionals (YPs). On the other hand, SPE and the industry must learn from YPs on how to become the SPE2.0 that they find appealing. When YPs ask "what's in it for me," we must have great answers – and we do. Attracting tech-savvy millennials to the business will make E&P more competitive.

What do you want your legacy to be?

I'd like to be known for several things. First, that I reminded everyone in the E&P 'eco-system' of the 'changing the world' part of their job description, and what a force for good they are locally and globally. The energy they produce fuels human progress and gives us a huge sense of purpose. Second, I wanted SPE to rush the latest technology, the best methodology, the safest approach and the newest E&P business models out to our 124,000 members without delay. Lastly, that I helped SPE to constantly renew itself, becoming SPE2.0, SPE3.0 and SPE4.0. SPE can renew itself by embracing new e-tools for sharing, connecting and disseminating, as we never stop our quest for having a great value proposition to members and the industry.

Haldorsen is an enthusiastic visionary. He would have been one to say "why not?" when man first conceived the idea of going to the moon. The oil and gas industry needs more people like Haldorsen, with an optimistic view paired with a dose of realism regarding the leaps that this industry can achieve in terms of technology, collaboration and fueling human progress. Why not? OE

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

***Kelli Lauletta** is an HR consultant with 17 years experience. She also serves as an editor for OilOnline.com. If you have story ideas email Kelli at klauletta@atcomedia.com.*

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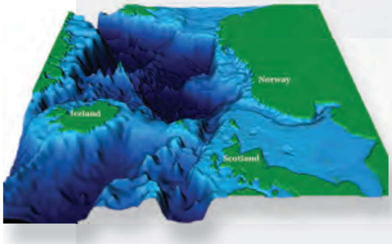
Numerology

7000ft

The water depth at Chevron's Jack/St. Malo development in the Gulf of Mexico. See page 16.

8-12billion bbl

The estimated reserves of the pre-salt Libra field offshore Rio de Janeiro. See page 20.



200mi

The width of the Faroe–Shetland Channel, a gorge-like feature, heading southwest to northeast, between the Faroe Isles and Shetland. See page 23.

US$117billion

The total subsea hardware capex between 2014 and 2018. See page 30.

2005

The year BP's Rhum field first came online. See page 46.

92

The amount of new installations are expected to be installed offshore the UAE alone in 2012-2017. See page 69.

22Tcf

The estimated gross natural gas resources of Noble Energy's Leviathan field off Israel. See page 72.

16MMbbl

The production storage capacity for the FPSO vessel designed for the Tartaruga Verde and Tartaruga Mestica fields offshore Brazil. See page 16.

40

The number of years OE has been published. See page 76.


UNCE