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East Africa

Offshore Engineer • July 2014

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July 2014

ON THE COVER

New frontiers. An onboard-view from the Transoceans' *Discoverer Americas* drillship working off the coast of Tanzania. The photo was taken on 27 September 2013. Image Credit: Paul Joynson-Hicks/AP/Statoil.

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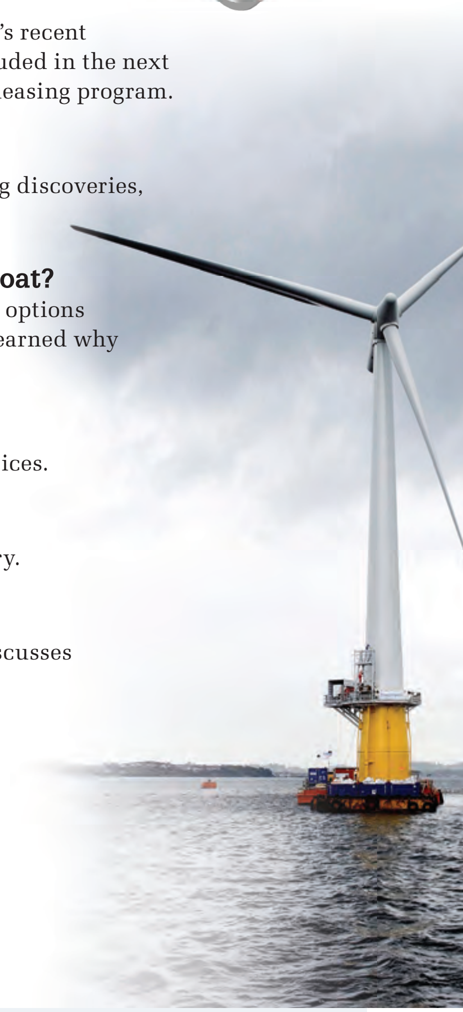
Departments & Columns

"Do industry programs promoting STEM actually do enough to encourage children/teens to pursue engineering?"



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

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

Currently @ OEdigital.com

Online Exclusive

Offshore GTL

Sarah Parker Musarra examines how floating production storage & offloading vessels allow GTL to be processed offshore, making it more economical than ever to recover stranded associated gas.

What's Trending

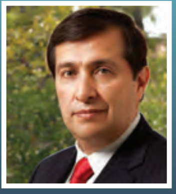
Stops and starts

- Activists mount two Arctic-bound rigs
- Jackup arrives at Dolginskoye field
- Martin Linge taking shape
- Equipment failure on Deepwater Nautilus
- Valemon topside en route to Norway
- Fire strikes Petrobras platform
- BP launches Alaska drone program

The GSP Saturn jackup rig en route to Dolginskoye. (Photo: Gazprom Neft)

People

García heads Pemex E&P



Gustavo Hernández García has been officially named director general of Pemex Exploration & Production. García has served in the role since February, following the exit of Carlos Morales Gil.

Noreco CFO out

Noreco's CFO Ørjan Gjerde resigned to begin a new business venture. Noreco says the search for his replacement has already commenced. Gjerde played a central role in the financial and operational restructuring of the company, most notably its 2013 refinancing.

Voices

Changing of the guard. With skills shortages still high on the agenda, young people need to be recruited as early as possible, OE asked:

Do industry programs promoting STEM actually do enough to encourage children/teens to pursue engineering?

Industries must work closely with educators to develop instructional approaches that show students how STEM subjects relate to their lives, and introduce them to the many potential STEM careers. With the world literally at their fingertips, children and teens should understand the importance of addressing global challenges. Let's show them that they can take STEM into a career developing sustainable energy resources, curing diseases, eliminating hunger – making a lasting difference.

Cindy Bigner,
Sr. Director, Corporate Affairs & Diversity Initiatives, Halliburton

It takes a village to raise a child, so the saying goes, and that is no different when encouraging children into STEM education and careers. Programs like the Power of Engineering Inc. are avenues for industry to take action in the education of their future workforces. We know from results that the programs work to increase awareness and adoption of STEM learning by high school students who are willing to meet industry half-way. Getting more industry to join those members already at the table is the other half of the challenge; industry should take opportunities to take the lead in critical future capacity building.

Doug Hargreaves, Professor,
Queensland University of Technology

Yes. There is a huge amount of work being undertaken by individual companies and at industry level to engage and encourage the uptake of STEM subjects. By giving young people a better understanding of oil and gas we can guide them towards these stimulating subject areas and, in turn, keep the industry expanding with fresh talent.

Over one million pupils have been reached by OPITO initiatives in schools and although it may take a few years before we see the full impact of this process from choosing STEM subjects at school, going to university or an apprenticeship, and finally being employed in the industry, the fact there's massive interest from pupils and teachers demonstrates there's a great future in oil and gas for the next generation.

In the meantime, we need to continue energizing and encouraging young people to look to the oil and gas sector as an exciting career choice with exceptional opportunities both onshore and offshore.

Morven Spalding,
Skills Director, OPITO

ExxonMobil has a long history in supporting education efforts and I am proud of the focus on addressing the STEM challenge by preparing young people to acquire math and science knowledge to be successful in college and careers.

World-class programs such as the National Math and Science Initiative and Bernard Harris Summer Science Camps are effective ways to accomplish this, along with the work of the National Action Council for Minorities in Engineering and Discover Engineering.

But more needs to be done to inspire and prepare America's youth to pursue engineering. ExxonMobil's new TV commercial, "Be an Engineer," is designed to be a call to action, and highlights engineering solutions to global challenges.

Marilyn Tears,
Julia Senior Project Manager,
ExxonMobil Development Company

Students need to learn science and engineering the old fashioned way: through curiosity and discovery. Industry currently inspires young children by sponsoring festivals and events highlighting the playful nature of discovery and learning. The pressing issue is whether this is enough to capture and draw interest to the STEM pipeline. Outdated curricula and overly burdened teaching staff regularly reduce the joy of science for many children. Schools need assistance in funding professional development for teachers and in acquiring scientific supplies so science and engineering can be experienced as exciting and fun every day of the week.

Barbara Moskal,
director of the Colorado School of Mines Trefny Institute of Educational Innovation

Much is being done but we need to broaden our approach. Rather than focusing on students who already show promise in STEM, we must work with society more broadly, and the next generation in particular, so that they appreciate the power and impact of STEM. Only when everyone engages with STEM is it mainstream, and only then will we be able to reap its true potential. Creativity with STEM, and enthusiasm for STEM, as a vehicle to shape and to change our world must be fostered. Starting at pre-school is not too soon. We want to collaborate in this space.

Iven Mareels, Dean of Engineering, The University of Melbourne

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

Editor's Column

Nina Rach

Colloquy

Energy and capital: Operators reinvest cash

Business is good in the oilfield, and as increased production and steady commodity prices contribute an influx of cash, operators are reinvesting in themselves, expanding their share buyback programs. Management usually says that the share repurchases create long-term value for shareholders, reducing the total outstanding shares of the company.

Buybacks are also a mechanism used when stock prices are perceived to undervalue company assets.

Burgeoning cash balances from stable production revenues and company streamlining through asset divestment support most share repurchase programs.

Buyback programs usually result in a rise in share price, one way of returning wealth to shareholders, in addition to paying regular dividends. The programs also garner favorable responses from financial analysts and positive market buzz.

For smaller companies, however, shareholders may question whether the company is retaining enough free cash to grow their operations.

Majors

According to The Energy and Capital newsletter from Angel Publishing: "There's a steady liquidation of the world oil industry... Exxon is buying back about US$30 billion of its shares each year. If that continues, Exxon will have repurchased all its stock by about 2024."

The same article goes on to say that the Big 5 (Exxon, Chevron, BP, ConocoPhillips and Royal Dutch Shell) are spending more on stock buybacks than they are on finding new oil.

Anglo-Dutch Royal Dutch Shell buys back about half a million of its own 'A' shares daily, although it's worth noting that there are just short of four billion 'A' shares outstanding.

In March, Shell announced a buyback program for 'B' shares in April, saying "the purpose of the share buyback program is to offset dilution created by the issuance of shares for the company's Scrip Dividend Program. At this time, it is less economic for the company to purchase 'A' ordinary shares under the share buyback program due to Dutch dividend withholding tax rules."

BP has been re-aquiring its shares for several years. After announcing it would sell its 50% stake in Russian TNK-BP a year ago, it also announced an $8 billion share buyback program.

In April, BP Chief Executive Bob Dudley said more share buybacks were planned, as the company also increases its quarterly dividend payments.

In March, Chevron Corp. said its dividends and share repurchase program would be internally funded by 2015-2016. The company told analysts it expected its operating cash flow to grow from $35 billion in 2013 to above $50 billion in 2017, driven by 20% production growth over the period and improved cash margins. It plans to monetize about $10 billion assets from 2014 to 2016 (20% midstream, 80% upstream).

Marathon Oil Corp. is pursuing a two-stage, billion dollar program to buy back common shares. The first stage, buying up $500 million of stock, was completed last year. The second phase is an additional $500 million in share buybacks, fully funded by divestment of the Marathon's 10% ownership in offshore Angola Block 31 to Sonangal Sinopec International Ltd., a subsidiary of China's Sinopec, for about $1.5 billion.

Eni SpA has been buying back shares, and although as of late April, it held nearly 22 million shares, this represents only 0.60% of the share capital.

Middle East

Dragon Oil, the cash-rich explorer that is controlled by Dubai's Emirates National Oil Co. has production assets off Turkmenistan. In September 2011, it began buying back shares. Then in June 2012, it launched a $200 million share buyback program to repurchase up to 5% of its outstanding shares.

Australia

Australia's Murphy Oil Corp. has followed a steady share buyback strategy, completing a $1 billion program last year, and an additional $250 million in 1Q 2014.

Murphy's board of directors approved a new share repurchase program in May that allows the company to repurchase up to $125 million in shares of common stock. No details announced, but the company will complete by the end of this year.

Woodside Petroleum Ltd. recently announced it was buying 9.5% of its outstanding stock from Shell for US$2.68 billion, based on a share price of AU$36.49, a "14% discount to volume weighted average price up to and including 16 June 2014." Shell sold another 9.5% to institutional investors.

Service companies

Luxemburg-based Subsea7 SA has been buying back shares through 4Q 2013 and 1Q 2014. At the end of 2013, it held indirectly about 4% of issued shares, in addition to shares held in an employee benefit trust. OE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ThoughtStream

Randall Luthi, National Ocean Industries Association

Stepping towards energy security

It is the first step in a long process. That is probably the best synopsis of the recent announcement by the Department of Interior's (DOI) Bureau of Ocean Energy Management (BOEM) requesting information on areas to be included in the next Outer Continental Shelf (OCS) oil and gas leasing program. Known as the five-year program, it derives from the Outer Continental Shelf Lands Act authorizing the DOI (through BOEM) to conduct sales of oil and natural gas leases in federal waters off the US. We are currently in the 2012-2017 five-year program. This call for information starts the information gathering process for the 2017-2022 program.

The recent surge of US energy has occurred largely from onshore oil and natural gas development. Production from the Marcellus Shale in Pennsylvania, Eagle Ford in Texas and, in particular, the Bakken in North Dakota, has propelled the US to be the world's leader in natural gas.

We may also soon be the leader in oil production, provided US policies don't end our run before we reach the finish line. That could well happen, because the great oil and natural gas production of the past five years has occurred in spite of federal policies, not because of them. Ninety-six percent of the new production occurred on state and private lands.

While some of that is due to geology, the fact remains that oil and gas companies can only look in areas they are allowed to explore, and federal decisions have greatly limited that target area. For more than 40 years, almost 87% of the OCS has been closed to oil and natural gas exploration. In 2008, the US Congress and the White House allowed nearly all congressional and executive moratoria prohibiting oil and natural gas exploration activities to expire. The Obama Administration even recommended opening up part of the Atlantic Coast for a lease sale in an early version of the 2012-2017 program. However, post-Macondo, the program was cut back to include only the approximate 13% of the OCS already open.

As a nation, we cannot afford for the upcoming program to suffer a similar fate. However, President Obama's recent remarks on the energy impact of turmoil in the Middle East indicate he still looks abroad, even when there are tremendous untapped energy resources at home, resources the president is overlooking.

"Obama's recent remarks on the energy impact of turmoil in the Middle East indicate he still looks abroad, even when there are tremendous untapped energy resources at home."

As unrest in Iraq caused oil production to drop, the president called upon Middle East Gulf oil producers to "pick up the slack." Once again, the US shows our dependency on the Middle Eastern countries. Many of these are not our political allies and wouldn't hesitate to cut off all oil exports to the US. The president has misdirected his plea. He needs only to clear the way for domestic oil and natural gas producers to increase production by opening up more areas offshore where companies can explore and produce to pick up the slack.

While the US has sat on its offshore assets, other countries have not. The current five-year program that expires in 2017 included no new access, and has put the US far behind many other nations that are actively pursuing offshore oil and natural gas energy development, particularly in the Atlantic basin and the Arctic. Canada, Mexico, Venezuela, Brazil, Norway, Russia, Cuba and west African nations are examples of countries moving ahead with Atlantic and Arctic offshore exploration and development plans.

The energy resources on the OCS are vital to our economic prosperity. Allowing oil and natural gas development in the Atlantic could result in as many as 280,000 new jobs; US$24 billion annually to the economy; $51 billion in government revenue; and 1.3MMbbl of oil and natural gas. Frankly, these numbers likely underestimate the potential.

The DOI's request for more information is crucial, but still only a first step in truly adopting a holistic energy policy. The over-320-member companies of NOIA look forward to cooperating enthusiastically with stakeholders, including states and consumer groups, and with BOEM to provide information about what areas to include in the 2017-2022 five-year program. NOIA will also continue to work closely with Congress on legislation to identify areas to include in the program that would open up new and vital areas to enhance our energy security and reliability. **OE**

Randall Luthi became president of the National Ocean Industries Association (NOIA) on 1 March 2010.

Luthi most recently served as the director of the Minerals Management Service at DOI from 2007-2009, overseeing activities such as offshore lease sales and the collection and distribution of mineral revenues and royalties.

The former Wyoming speaker of the house, Luthi was also the director of a Federal agency, a legislative assistant in the US Senate, and an attorney at both the DOI and the National Oceanic and Atmospheric Administration (NOAA).


ABS Group

Global Briefs

A OCS plan released

The US Department of the Interior has opened its new five-year Outer Continental Shelf (OCS) offshore oil and gas leasing plan to public comment. The DOI said the publication in the federal register of the 2017-2022 OCS leasing program (RFI) begins a 45-day public comment period. BOEM will evaluate all of the OCS planning areas during this first stage. The planning process will take up to three years to complete.

B Noble acquisition

Noble Energy will acquire interest in 17 deepwater exploration leases located in the Atwater Valley region of the Gulf of Mexico from BP Exploration & Production. Noble Energy will acquire a 50% interest in 13 deepwater leases, along with an average 26% interest in four additional leases. It will add 50% interest in the Bright prospect located in Atwater Valley Block 362, currently being drilled by the *ENSCO DS-4* drillship in water depths of 5600ft.

C ICA Fluor workers in deadly accident

Seven employees of ICA Fluor died while working on Pemex's Ayatsil-C platform. Another employee sustained serious injuries. The accident occurred in ICA Fluor-subsidiary Industria del Hierro's yard, located in the state of Veracruz. A personnel transporter, hoisted by a 600ton Manitowoc crane, fell from a height of about 40m. During the fall, the transporter struck another group of workers. Five died upon impact, and two later succumbed to injuries.

D New platforms for HPHT Culzean

Operator Maersk Oil will use a new standalone installation to develop the ultra-high-pressure, high-temperature Culzean gas field in the central North Sea, about 145mi. east of Aberdeen. The Culzean field, one of the largest gas discoveries of recent years in the UK North Sea, is located in about 88m water depth. The field will be comprised of a 12-slot well head platform and will be developed using a complex of bridge-linked platforms. It could then support future projects in the area as part of a cluster development.

E Catcher advances

Premier Oil's central North Sea Catcher field development plan has been approved by the UK Department of Energy and Climate Change. The Catcher area is expected to produce 96MMboe, with a peak production rate of around 50,000bo/d. The project is comprised of 22 subsea wells on the Catcher, Varadero, and Burgman fields tied back to a leased FPSO. Oil will be offloaded by tankers, with gas exported through the SEGAL facilities. First oil is targeted for mid-2017.

F Eni's Goliat FPSO delayed

Delivery of the *Goliat* floating production, storage and offloading platform (FPSO) has been delayed until early 2015. Operator Eni Norge said that conditions to depart at the end of June 2014 and complete commissioning in Norway 4Q 2014 were not in place. The FPSO will be used to produce the first oil field in the Barents Sea.

G Falkland Islands drilling inked

Ocean Rig's deepwater, harsh environment semisubmersible drilling rig *Eirik Raude* has been contracted by Premier Oil to drill four wells in the North Falklands basin and, under a rig sharing agreement with Noble Energy, two wells in the South and East Falklands basin. Partner Rockhopper Exploration says the four targets in the North Falklands basin along could contain more than 520MMbbl net to Rockhopper. Drilling could start as early as 1Q 2015, and there are options for a further 16 wells.

H SBM axes Brazilian tenders

Dutch floating platform leaser SBM Offshore will not participate in the upcoming Petrobras Tartaruga Verde and Libra tenders. SBM is the subject of an investigation alleging that it dealt out more than US$130 million to Brazilian government officials in exchange for FPSO contracts. The company released findings in April from an internal investigation that originated 1Q 2012 announcing that the investigation did not unearth "credible evidence" of improper payments in Brazil.

I Eni ups African presence

Eni secured operatorship and a 40% interest in exploration right permit 236 (ER236) off the eastern coast of South Africa from Sasol. Under the terms of the agreement, Eni has acquired 82,000sq km of unexplored acreage in the Durban and Zululand basins within the Kwazulu-Natal province. The financial terms were not disclosed. Sasol originally acquired the three-year permit in November 2013 by the Petroleum Agency of South Africa.

J Total's CLOV in production

The CLOV floating production storage and offloading (FPSO) development, located in Block 17 offshore Angola, began production on schedule. The development is expected to reach daily production capacity of 160,000bbl in the coming months. The project includes 34 wells and eight manifolds connected by 180km of subsea pipelines to an FPSO unit in 1110-1400m water depth.

K BG strikes Tanzanian gas

BG Group made a new gas discovery in Block 1 in the Mafia Deep basin off Tanzania.The Taachui-1 well's net pay amounted to 155m, with estimates for the mean recoverable resource placed at 1Tcf. *Deepsea Metro I* drilled to 4215m total depth, and a single column of 289m of gas was encountered within the targeted Cretaceous reservoir interval. Due to the size of the gas column, Ophir said the discovery could be extended into a similarly-sized second compartment to the west. **Read more about Tanzania on page 58.**

L Tunisian drilling starts up

Circle Oil has started drilling exploration well EMD-1 on the offshore Mahdia Permit using the drillship *PetroSaudi Discoverer*. The well is near existing producing fields, including the Tazerka, Birsa, Oudna, and Halk El Menzel oil fields, and the Maamoura gas field. The well is planned to test the play potential of the El Medioumi prospect, including the primary Birsa Sands target and the secondary fractured carbonates of the Ketatna Formation.

M First oil off East Africa

BG Group made the first oil discovery off East Africa in the Sunbird-1 exploration well, off the southern Kenyan coast. A 14m gross oil column was found beneath a 2936m gross gas column in a reefal limestone reservoir in the Sunbird Miocene Pinnacle Reef in area L10A. The top of the Sunbird Miocene Pinnacle Reef was reached at 1583.7m subsea, in 723m water depth. The 43.6m gross hydrocarbon bearing zone is assessed to contain a net pay thickness of 27.8m. The Sunbird Reef is an ancient Miocene pinnacle reef buried beneath approximately 900m of younger sediment, says Pancontinental. **Read more on Kenya on page 60.**

N Muridava plugged

Petroceltic International's Muridava-1 exploration well on the Muridava (EX-27) license in the Romanian Black Sea has been plugged and abandoned after failing to find commercial hydrocarbons. The well, spudded 11 April and drilled to 2747m total depth, was the first exploration well drilled by the Muridava concession owners.

O Woodside exits Leviathan

Woodside Energy has axed its plans to purchase a sizeable stake in Israel's Leviathan gas project, terminating its February memorandum of understanding with the joint venture participants. This decision concludes a prolonged and complicated negotiation period, beginning in December 2012, when Woodside purchased 30% of Leviathan. Australia's biggest producer said that negotiations "failed to reach a commercially acceptable outcome."

P Filanosky field takes shape

Work to transport a 10,250-ton central processing platform topside section for the Vladimir Filanovsky field in the Russian sector of the Caspian Sea has started. The Russian Maritime Register of Shipping said the topside was transferred from the quay to the *Yury Kuvykina* barge at the sub-assembly yard in Ilyinka, Astrakhan region. The second stage facility of the V. Filanovsky field development - an ice-resistant fixed platform (IFP 2) - was laid down at OOO Galaktika shipyard, Astrakhan.

Q Kashagan frozen for 2014

North Caspian Operating Co. BV (NCOC), the seven-company consortium behind Kashagan development, confirmed that production is not expected to resume in 2014. Both oil and gas lines might have to be fully replaced, NCOC said. Gas leaks have halted operations twice since Kashagan's 11 September 2013 start-up. The tender process for the purchase of pipeline joints has been initiated, and a full replacement plan is expected to be completed by mid-2014. The NCOC itself will see some restructuring. ExxonMobil secondee Stephane de Mahieu is the new managing director. The consortium will consolidate some activities that were previously split between the co-venturers. No changes to the production sharing agreement or to the ownership are currently foreseen.

R FLNG concepts offered

Wison Offshore and Marine presented two concepts to the Pandora LNG joint venture partners for development of the Pandora gas field offshore Papua New Guinea. Wison was asked to deliver a floating liquefied natural gas (FLNG) concept study for the field, located about 200km west of Port Moresby, and estimated to have a 2C contingent resource of around 792Bcf of gas.

S Salamander HoA

Salamander Energy signed a non-binding heads of agreement with SONA to sell an effective 40% working interest in both the B8/38 concession (containing the Bualuang field) in the Gulf of Thailand and the surrounding G4/50 concession. The deal would be worth US$280 million. Salamander will carry SONA's costs associated with the drilling of two exploration wells in the G4/50 concession up to an agreed cap. SONA will pay Salamander a contingent cash payment in the event of a commercial discovery in G4/50 of up to $15 million.

T Gas well discovery

SapuraKencana Energy Sarawak Inc. discovered four non-associated natural gas wells within the SK408 production sharing contract, a 4480sq km area around 120km offshore Sarawak, Malaysia, in the Central Luconia gas province.

U AziPac farm-in

Mitra Energy Ltd. entered into a farm-out agreement with AziPac for the partial assignment of Mitra's participating interest in the Bone PSC offshore Indonesia. Mitra will assign a 40% participating interest in Bone PSC to AziPac. An independent best estimate for the gross unrisked prospective resource potential is 2074MMboe with an upside resource of 4266MMboe.

V Offshore permits awarded

Industry Minister Ian Macfarlane awarded nine new permits located in Commonwealth waters offshore Western Australia, Victoria, and the Territory of Ashmore and Cartier Islands as part of round one of the Australian government's 2013 Offshore Petroleum Exploration Acreage Release.

W AWE begins drilling Oi-2

AWE Ltd. began drilling the Oi-2 exploration well located in Petroleum Mining Permit (PMP) 38158 offshore Taranaki, New Zealand. Oi-2 will be drilled to a planned total depth of 3881m. Oi-2 is located about 12km northeast of the Tui Area Oil Fields in around 120m of water. Operator AWE anticipates hydrocarbon discovery from the same F10 reservoir sandstones that produce similar fields Tui, Amokura, and Pateke.

Contract Briefs

GOM win for Subsea 7

Freeport-McMoRan Oil & Gas awarded Subsea 7 a contract worth more than US$50 million in support of the Gulf of Mexico's KOQV and Holstein Deep fields. The work scope covers the installation of flexible pipelines and umbilicals for both fields, with the offshore installation phase expected to be executed by the Subsea 7 vessel *Seven Seas* in 4Q 2015.

Total contracts Ocean Rig drillship

Ocean Rig UDW Inc., a subsidiary of Athens-based DryShips Inc., has signed a six-year contract with Total E&P Angola for drilling operations in Block 32 offshore Angola, using the ultra-deepwater drillship *Ocean Rig Skyros*. Total plans to include the production from oil fields Gindungo, Gengibre, Canela, Mostarda, Louro, Salsa and Caril. The contract is expected to begin 3Q 2015 and has an estimated backlog of US$1.3 billion.

Oceaneering snags umbilicals contract

Oceaneering secured a contract from FMC Technologies Singapore to supply umbilicals for the Jangkrik project located in the Muara Bakau production sharing contract area off Indonesia. The order is for super-duplex steel tube production control umbilicals, with a total combined length of around 50km. These will be used to supply hydraulic and electrical power and chemical injection to the subsea wells in the field. Delivery is scheduled for 2Q 2016.

DNV grabs Goliat contract

Eni Norge awarded DNV GL a framework agreement for the supply of inspection services to the *Goliat* platform in the Barents Sea. The term of the contract is three years, with an option for a two-year extension. The assignment consists of planning and carrying out inspections of static equipment, load-bearing structures and the offloading and anchoring systems aboard the *Goliat* floating production, storage and off-loading unit (FPSO) during its operational life. The estimated reserves in Goliat field are 174MMbo and 8 billion cu. m of gas.

Atwood inks Aus and Thai contracts

Houston-based drilling rig operator Atwood Oceanics was awarded a drilling services contract by BHP Billiton Petroleum for the semisubmersible rig Atwood Falcon. The contract is for 330 days and the work will be performed offshore Australia at a US$430,000 day rate. BHP Billiton retains the right to further extend the contract for two option periods of about 120 days each at the same rate.

Wood Group wins Shah Deniz 2 contract

BP Azerbaijan awarded London's Wood Group a US$60 million call-off contract for the Shah Deniz 2 project under a 2007 global agreement. The contract covers subsea engineering and project management services during the subsea execute phase. Wood Group has worked with BP on the $28 billion Shah Deniz project since 2008. This contract is in addition to the subsea engineering work currently being carried out under the BP Global Agreement covering engineering and project management services in the North Sea, Angola and Gulf of Mexico. ■

A growing number of companies are eying options for floating offshore wind. Elaine Maslin learned why at All Energy in Aberdeen.

Offshore wind ready to float?

This year could see something of a sea-change in offshore wind power development. What has, until now, been a mostly fixed-foundation industry, using monopiles and jackets, is increasingly looking to floating solutions.

Floating wind designs have been driven by a move into deeper waters, areas where wind energy potential is thought to be greater. There has also been a shift in geographic focus. Europe has been a leader in offshore wind development, but other countries are now looking to offshore wind, using floating designs.

"While Europe has both shallow and deeper waters, other areas such as the US and Japan can only have offshore wind in deeper waters," says Adrian Fox, program manager, technology and supply chain, at the UK's Crown Estate, which manages offshore leases for wind parks. This is because the water depths in their offshore areas make jacket or monopile-based foundations hard or impossible.

As well as practicality, cost is a key issue, Fox told a session focusing on floating offshore wind solutions at the All Energy conference in Aberdeen, in May. There has been an increase, not decrease, in costs for shallow water offshore wind projects, says Nico Bolleman, managing director Blue H Engineering, which has a tension leg platform wind turbine design. "This is because turbines have become bigger and in deeper waters," he told the All Energy session.

By moving to floating structures, developers could help reduce costs, Fox suggests, by building and commissioning floating wind turbines onshore, removing the need for offshore lifting vessels, reducing offshore installation time. In addition, facilities could potentially be brought back to shore for operations and maintenance.

By using buoyancy instead of seafloor-fixed support structures, developers could reduce the amount of material they use, and therefore costs, Bolleman says. In addition, floating solutions will better deal with deep water conditions, avoiding having to pile or anchor into rocky seabeds, and higher winds and wave heights, which cause high dynamic loads, he says. Nor will a floating turbine require a transition piece—a component which has created a number of issues on fixed offshore wind turbines.

Using TLP designs, turbine structures would take up a smaller footprint, limiting incursions into fishing grounds. In addition, he suggests floating wind economics could be boosted through a tie-up with oil and gas operators, by using floating wind units to power enhanced oil recovery projects, such as subsea compression or boosting, says Johan Sandberg, service line leader, offshore renewable energy, DNV GL.

In fact, DNV GL recently launched a joint industry project to research the idea.

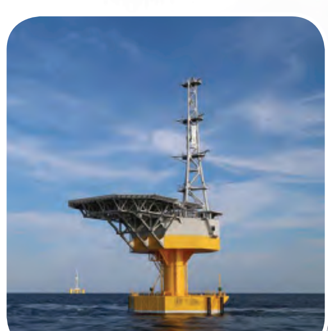
There are challenges, including non-linear frequency dynamics, says Patrick Rainey, control engineer, DNV GL, which could in turn make control optimization costly. Consideration will also need to be given to inter-turbine and substation cabling, as well as structures for transformers or substations.

But, says Fox: "The only real limitations offshore are imagination and engineering—capability to innovate. We thought 7-8MW turbines would be pushing it 3-4 years ago. But we do need to go further and I believe we will."

Japan

Japan has been quietly developing its floating wind capabilities. According to Main(e) International Consulting (MIC), 80% of Japan's offshore resources are in 100m+ water depth. In June last year, Prime Minister Shinzō Abe said: "Japan intends to become the first country to commercialize floating offshore wind power technology by around 2018."

DNV GL's Sandberg says Japan has an increased focus on



Top – The Fukushima Forward 2MW floating offshore wind turbine. Photo from Fukushima Forward.
Right – The Fukushima Forward spar-based floating substation. Photo from Fukushima Forward.
Far right – Statoil's Hywind floating wind turbine, offshore Norway. Photo by Hild Bjelland Vi, Statoil

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)	104	74	69	18
Deep (500-1500m)	25	24	19	5
Ultradeep (>1500m)	18	37	32	2
Total	**147**	**135**	**120**	**25**
Start of 2014 date comparison	151 4	135 -	98 22	- 25

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	15	603.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	45	13,235.25	18,090.00
United States			
Shallow	21	106.25	322.00
Deep	20	1,510.11	1,654.57
Ultradeep	33	4,825.50	4,690.00
West Africa			
Shallow	168	4,572.47	22,447.05
Deep	50	5,886.50	7,170.00
Ultradeep	17	1,835.00	3,210.00
Total (last month)	**370** (385)	**34,586.08** (35,335.38)	**60,098.62** (61,249.40)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow (last month)	1255 (1,284)	48,376.31 (51,992.51)	827,387.48 (831,554.26)
Deep (last month)	163 (164)	12,591.98 (12,559.48)	99,259.77 (100,059.77)
Ultradeep (last month)	110 115	20,435.75 20,450.75	57,657.00 60,257.00
Total	**1,528**	**81,404.04**	**984,304.25**

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,407	(41,688)
Planned/ possible	24,640	(24,447)
	66,047	(66,135)
8-16in.		
Operational/ installed	77,988	(78,250)
Planned/ possible	50,014	(49,698)
	128,002	(127,948)
>16in.		
Operational/ installed	89,687	(89,823)
Planned/ possible	49,948	(48,241)
	139,635	(138,064)

Production systems worldwide

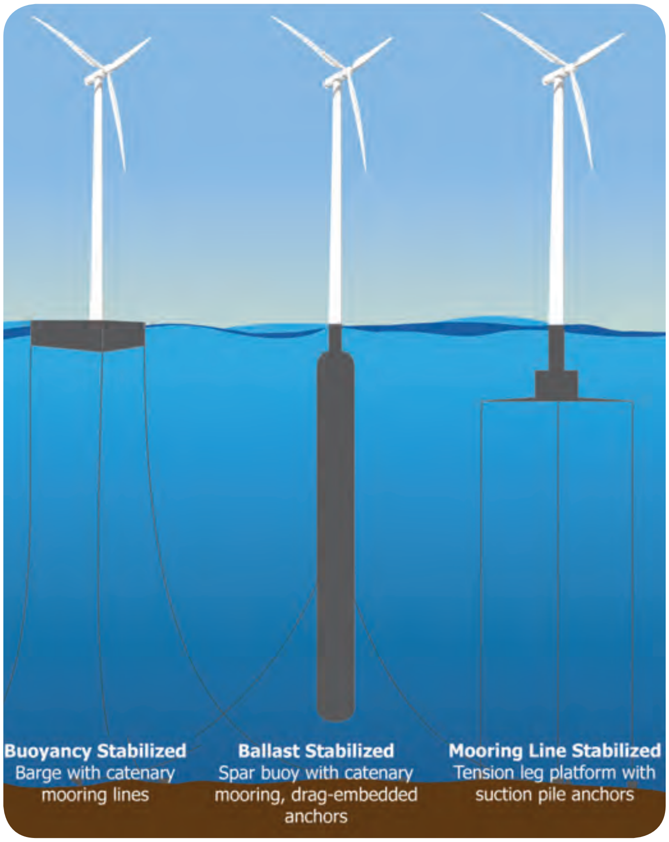
(operational and 2014 onwards)

Floaters		(last month)
Operational	278	(273)
Under development	41	(45)
Planned/possible	335	(330)
	654	(648)
Fixed platforms		
Operational	9,378	(9,435)
Under development	123	(105)
Planned/possible	1,398	(1,399)
	10,899	(10,939)
Subsea wells		
Operational	4,511	(4,514)
Under development	436	(421)
Planned/possible	6,375	(6,368)
	11,322	(11,303)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow	6,013.67	23,663.26	47,785.52	36,900.08	32,485.93	46,422.29	31,308.88
(last month)	(6,013.52)	(23,665.64)	(48,211.78)	(37,696.72)	(35,133.46)	(47,708.06)	(30,510.50)
Deep	2,817.87	484.3	4,598.44	5,860.74	4,317.40	5,401.84	9,904.55
(last month)	(2,817.87)	(484.3)	(4,598.44)	(6,424.40)	(3,941.05)	(5,460.09)	(9,767.54)
Ultradeep	737.15	2,932.94	2,817.43	1,932.29	5,193.17	13,935.16	6,723.10
(last month)	(737.15)	(2,932.94)	(2,830.93)	(2,168.67)	(5,255.06)	(14,060.03)	(6,759.86)
Total	**9,568.69**	**27,080.50**	**55,201.39**	**44,693.11**	**41,996.50**	**65,759.29**	**47,936.53**

11 June 2014



The DeepCwind Consortium is investigating three general designs for modeling at the University of Maine Deepwater Offshore Wind. Image from Advanced Structures and Composites Center, Maine.

renewables post-Fukushima and that its expertise in steel, experience in lean manufacturing, and spare yard capacity, means it is in a strong position from which to develop floating wind technology.

A number of scale prototypes have already been installed offshore Japan. Last year saw a 66kV spar-based substation and a 2MW downwind turbine on a semisubmersible base installed at Fukushima. In 2014-15, as part of the Fukushima Forward project, two turbines, one on a Mitsubishi-designed, V-shape-semisubmersible base and one on a Japan Marine United designed-advanced spar, are due to be installed, both using Mitsubishi turbines, in 100-200m water depth, and average 7m/s wind speed, 20km offshore Fukushima. Fukushima Forward is funded by Japan's Ministry of Economy, Trade and Industry and consists of a consortium with Marubeni Corp. acting as project integrator.

Japan's Hitachi Zosen has also been working with Statoil on floating wind development. A 2012 agreement between the two companies was extended in April this year and HZ is reported to be planning 7.5MW pilot plants by 2016, before building wind farms with a combined capacity of 300MW in 2022.

Scotland/Norway

A site offshore Scotland could be home to the UK's first floating wind park, led by Norway's Statoil, using its Hywind design. Kelly Meulepas, senior engineer, Statoil, told All Energy Hywind is a ballasted steel structure, which can be towed to site and moored with three mooring lines.

A demonstrator Hywind unit was installed off Norway in 2009, using a 2.3MW Siemens turbine. It has produced more than 37.6GW hours of electricity, and survived 44m/s wind speed and 19m wave heights, Meulepas says. The latest Hywind design will be used in the proposed Hywind Scotland Pilot Park Project (HSPP), a five-turbine development, 5km offshore Peterhead, in an area with 10.1m/s average wind speed, 95-120m water depth, and in 1.8m mean wave height.

The structure below sea level will be 75m-long (25m shorter than the first Hywind demonstrator). It will use dynamic power cables in a lazy S formation, with 33vV transmission voltage to shore. The company carried out geotechnical studies this spring. A final investment decision is due to be made on HSPP in 2015.

Statoil's Hywind floating wind turbine, offshore Norway.

"Our goal is a large-scale commercial park, producing 500-1000MW, which we believe could be cost-competitive with bottom fixed turbines from 2020. We need to build a small wind farm to demonstrate the cost reductions and risk," Meulepas says.

Challenges for the larger units offshore Peterhead will include installation, which will need to be different to the Hywind offshore Norway, Muelepas says, as well as maintenance and marine systems.

Spain

In Spain, the Nautilus Floating Solutions consortium is developing a floating wind turbine. The consortium comprises four companies in northern Spain (the Astilleros de Murueta shipyard, Tamoin industrial services firm, Velatia, an industrial and technology group working in electronics and communications, and mooring system firm Vicinay) and the Tecnalia technology center. The consortium has a collaboration agreement with Spanish utility group Iberdrola.

Gonzalo Fornos, business managing director at Tamoin and a board member on Nautilus, told All Energy the group has developed a floating, stabilized, semisubmersible platform, for 50-250m water depth. As well as accommodating "any type of wind turbine," it could take a substation, Fornos says. Concept definition was achieved in 2011, conceptual design was achieved in 2013, and tank testing will be carried out this year, at the University of Cork, Ireland, and in Cantabria, Spain. Detailed engineering will start in 2015, and a prototype is due to be deployed in 2016, Fornos says, with a commercial unit ready by 2018. The aim is to pre-assemble the unit in port, and tow it to its installation location. OE

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	103	100	3	97%
Jackup	418	364	54	87%
Semisub	192	165	27	85%
Tenders	34	22	12	64%
Total	747	651	96	87%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	28	0	100%
Jackup	95	76	19	80%
Semisub	28	26	2	92%
Tenders	N/A	N/A	N/A	N/A
Total	151	130	21	86%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	14	12	2	85%
Jackup	114	103	11	90%
Semisub	38	29	9	76%
Tenders	24	14	10	58%
Total	190	158	32	83%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	26	0	100%
Jackup	9	6	3	66%
Semisub	39	38	1	97%
Tenders	2	2	0	100%
Total	76	72	4	94%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	47	46	1	97%
Semisub	46	43	3	93%
Tenders	N/A	N/A	N/A	N/A
Total	94	90	4	95%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	103	88	15	85%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	107	92	15	85%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	32	31	1	96%
Jackup	26	21	5	80%
Semisub	20	17	3	85%
Tenders	8	6	2	75%
Total	86	75	11	87%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	24	24	0	100%
Semisub	18	9	9	50%
Tenders	N/A	N/A	N/A	N/A
Total	43	34	9	79%

Source: InfieldRigs

12 June 2014

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

Floating concepts

The Crown Estate's Adrian Fox says there are three main types of floating turbine structure: semisubmersible, TLP, and spar.

In October, 2011, US-based Principle Power deployed a full-scale prototype WindFloat using a 2MW Vestas turbine, 5km off the coast of Aguçadoura, Portugal. The semisubmersible is connected by subsea cable to the local grid. The structure was completely assembled and commissioned onshore before being towed some 400km along the Portuguese coast.

US-based PelaStar's TLP was conceived in 2006, by naval architects at Glosten Associates. It has been designed for water depths greater than 65m. In 2013, the UK's Energy Technologies Institute (ETI) commissioned Glosten to carry out a FEED study for the deployment of PeleStar TLP technology. The demonstration TLP will use Alstom's 6MW Haliade 150 offshore wind turbine and the structure will be designed for installation and operation at Wave Hub, off the southwest coast of England. Belfast's Harland and Wolff is shipyard partner and Dockwise is project partner.

Netherlands-based Blue H Engineering has developed a TLP design using a ballasted (semisubmersible anchor blocks), tension-leg mooring system. It would be assembled onshore and able to be installed with one anchor handling vessel, without lifting vessels or divers, Nico Bolleman says. Installation could be in a large weather window, with 3m-high seas for tow-out and 2m-high seas for installation. Yard harbor draught would not need to be above 10m. Blue H installed a large scale (75% full size) prototype with a small wind turbine in 2008, in 113m water depth, 21.3km offshore southern Italy.

US-based Maine Aqua Ventus I has approval for a pilot-scale offshore wind farm, which will comprise two floating wind turbines, with 12MW capacity, in the Gulf of Maine, 2.5mi. off the southern coast of Monhegan Island and 12mi. off the coast of the mainland. The DeepCwind consortium, led by the University of Maine, launched its 1:8 scale floating prototype VolturnUS off Maine last year. Its research is funded by the US Department of Energy, the National Science Foundation, and others.

Winflo is a consortium between French group DCNS and Nass et Wind. Winflo has a semisubmersible design, planned for deployment in 2014, offshore France using a 1MW turbine.

Germany's GICON is developing the GICON SOF (Schwimmendes Offshore Fundament, or "Floating Offshore Foundation"). The development is in cooperation with partners, including the Technical University and Mining Academy Freiberg, Rostock University and Jaehnig GmbH. Construction of a full scale prototype and deployment in the German Baltic Sea is planned during 2014.

A French, EDF-led consortium, comprised of turbine designer Nénuphar, and Technip, is working on two 2MW prototype, floating Vertiwind vertical-axis turbines, due to be installed 5km off France's south coast in 2015.

Poseidon Floating Power, from Denmark, has developed the P37, a 1:2.3 scale of its P80 design, a wave and wind harvesting unit. P37 is a 37m-wide model, weighing about 320-tonne. It is in its fourth test phase, since 2008, sited off Onsevig Harbor, at the north coast of Lolland.

US-based Nautica Windpower has an advanced floating turbine (AFT) design, using a buoyant tower and single mooring point. It hopes to deploy a medium-scale AFT in 2016. ■

PRESENTED BY:

OE

5:00-7:00 PM

Reception in Exhibit Hall
Sponsored by:
HALLIBURTON

Session IV 3:30-5:00 PM

Steve Herman, Chevron

Increased Safety and Efficiency for Rigless Subsea Interventions
Bevan Morrison, FTO Services

Capitalising on the Opportunity and Quantifying the Threats: The Reality of Well Intervention
Gregory Brown,
Infield Systems Limited (UK)

Panel Discussion Reality of Well Life
Session Chairs:
Ronnie Northcut, Baker Hughes;
Brent Boyce, DOF Subsea

3:00-3:25 PM

Coffee Break in Exhibit Hall
Sponsored by: AkerSolutions

Session III 10:45AM- 12:00 PM

Helix GoM P&A
David Barber, Helix Well Ops US

Brian Stiels, ENI Petroleum

World's First RLWI Crown Plug Pulling
Gary Andrews, Welltec

How Composite Downlines Improves Operational Performance and Reduces Cost of Deepwater Interventions
Bart Steuten, Airborne Oil & Gas

Case Studies
Session Chairs:
Ben Huebner, Anardarko;
James Wells,
Marubeni Oil & Gas

7:00-8:30 PM

Hospitality Lounge @ San Luis Hotel
Sponsored by: HELIX ENERGY SOLUTIONS

Thursday, 14 Aug.

7:30-8:00 AM

Continental Breakfast in Exhibit Hall

8:05 AM

Introduction and Opening Remarks
Colin Johnston, Helix WellOps Inc.

8:10-8:30 AM

Keynote
Offshore Energy Trends
Mike Haney, Director,
Douglas Westwood

Session V 8:30-10:00 AM

Helix Riserless Ops UK, West Africa
Oliver Willis, Helix Well Ops UK

Advanced Well Capping Operations Using a Unique Offset Deployment Method
John B. Garner, Boots & Coots

10:00-10:25 AM

Coffee Break in Exhibit Hall
Sponsored by: AkerSolutions

Session VI 10:30-12:00 PM

Identifying and Closing Technology Gaps - Part I
Session Chairs: Jason Leath,
The Cross Group;
Curtis Blount,ConocoPhillips

Turning New Ideas into Reality: An Overview of RPSEA Charter and Future
James Pappas, RPSEA

Cost Effective CT Drilling and Intervention System
Dr. Keith Millheim,
Nautilus International LLC

Session IX 3:45 - 4:00 PM

Closing Session
Ray Stawaisz, Chevron,
Colin Johnston, Helix
Well Ops Inc.

Session VIII 2:45-3:45 PM

BSEE Approval Process for HPHT Well Completions and Interventions
Russell Hoshman, BSEE

Subsea Decommissioning
Bruce Crager,
Endeavor Management

Standard & Regulatory
Session Chairs:
Lynard Carter, BSEE;
John Bousa, FTO Services

Session VII 1:15-2:45 PM

Integrity Management of Risers to Support Deepwater Drilling and Production Operation
Judith Guzzo,
GE Global Research

Establishing Operational Fatigue Limits for Intervention Risers
Mark Cerkovnik P.E. and
Shankar Sundararaman,
2H Offshore

Ultra-Deepwater Riser Concepts for High Motion Vessels
Brian S. Royer, Stress
Engineering Services Inc.

Developing Ultra-High Electrical Conductivity Polymer Nanotube Umbilical
Dr. Christopher Dyke,
Nano Ridge Materials, Inc.

Identifying and Closing Technology Gaps - Part II
Session Chairs:
David Brown, FTO Services;
Jim McAllister, Shell

12:00-1:10 PM

Lunch in Exhibit Hall

Subsea LiDAR Technology: 3D Imaging in Deep Water
Mark Hardy, 3D at Depth LLC

Effect of Vessel Motion on the Fatigue of CT
Dr. Steven M. Tiption,
The University of Tulsa,
Mechanical Engineetring
Department

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Automation can fulfill skills shortage remotely

Greg Hale explains how leveraging automation for remote condition monitoring can help reduce cost and increase productivity.

It wasn't long ago that Wintershall's gas production platforms on the North Sea went through an optimization metamorphosis when the company opened a monitoring center for its offshore rigs at Den Helder in The Netherlands.

Wintershall's center for remote controlled operations (RCO), a contemporary facility onshore, was able to monitor, via radio transmissions, whether the production platforms were operating correctly. The control center has at least two staffers working there around the clock, which not only saved on platform personnel, it also cut down on flights to the platforms and reduced maintenance and logistics costs.

The ability to monitor and control the platforms onshore allowed the gas producer to leverage automation technology to its advantage by reducing costs and increasing productivity in an age when there is a shortage of available workers.

And that is more important now than ever as Baby Boomers and the knowledge they derived over years of hands-on experience are getting ready to pull up stake and depart the industry.

But one of the great challenges facing industry thought leaders, executives and everyday worker bees is figuring out a way to capture that innate knowledge that is taking that final flight back to shore.

Automation is the one word answer that comes closest.

"Before people retire we have to capture their knowledge," said Paul Bonner, with Honeywell Process Solutions' oil and gas vertical, at their 2014 Honeywell User Group conference held in June. "That is a part of what automation does, it is able to capture that information. A good example is procedural operations. There is the guy that has 20 years of experience that knows how to start that unit up or shut it down or prepare it for maintenance. In systems now there is a thing called procedural operations where we can actually capture those steps, those best practices inside the automation, so it is not on a book on a shelf. It is in the system. So when a young guy comes along that doesn't have the same skills, instead of having him try to interpret the book and figure out what to do, the system actually steps into it and tells him what to do and protects him. It is helping the system get smarter and capture the knowledge of that outgoing generation."

Training for the future

Instead of looking for a needle in the haystack and finding the person with the right experience and the perfect skill set, companies will be able to train younger workers and get them up to speed so they can handle the rigors of operations.

"We have to take young people and train them," Bonner said. "The population is growing and we have to find people interested in working in engineering and getting them trained with the right skill set. There is no shortage of people, it is just skilled people."

The skills shortage numbers are staggering. As baby boomers hit retirement age at a rate of 10,000/day over the next 16 years, there is no doubt the oil and gas industry will suffer from the loss of experienced workers.

The US Bureau of Labor Statistics expects 54.8 million total job openings within this decade – with 62% of those openings related to Baby Boomers leaving the workforce and not having enough skilled people to fill them.

In the North Sea alone, there is a need for over 120,000 skilled personnel in the next 10 years to leverage all the projected investment in oil and gas.

"Like any other industry there is a big shortage of skilled resources to do the project engineering and to maintain the assets afterward," Bonner said.

Automation and the Cloud

The idea of using Cloud technology is also handling some of the skill shortages.

"Cloud engineering has the ability to bring skilled resources from other locations to work on projects. So I don't have to say 'I need 40 skilled engineers to go to Houston to work on a project.' Whoever has the right skills to work on a project, can work on the project from their location so the talent pool is larger globally. The Cloud makes it a reality," Bonner said.

The skills shortage is not the only reason for the boom in automation. The days of offshore production with rigs standing on the bottom over a single set of wells is long gone.

In the Gulf of Mexico, there are fewer rigs because more wells employ subsea completions. On top of that, automation will be able to handle operations thousands of feet below the surface.

In addition, the new technologies allow for the integration of systems and equipment on the platform, which only makes sense.

"A lot of SIL 2- (safety integrity level) and SIL 3-rated equipment on the platforms are integrated with the DCS (distributed control system)," Bonner said. "We also see a lot of integration of the equipment on the platform. Before, there were a lot of very separate systems which require separate people to maintain them. We are seeing a big push not to simplify things but integrate them.

"For example, with automation technology instead of having turbines and compressors needing compressor controls and anti-surge controls that need a separate black box to do that, we can actually do it inside the DCS. In the subsea where you used to have the subsea interface on the platform and then we would have a DCS connection and somebody else would look after that. We have eliminated that (whole process) where we can now talk directly to and control the subsea completions on the seafloor. Control it from the DCS. We can eliminate a lot of these third-party technologies and black boxes, which means you need less people to maintain them."

A radio surveillance system in Den Helder in the Netherlands monitors the production operations of 18 offshore platforms that Wintershall operates in the southern section of the North Sea.

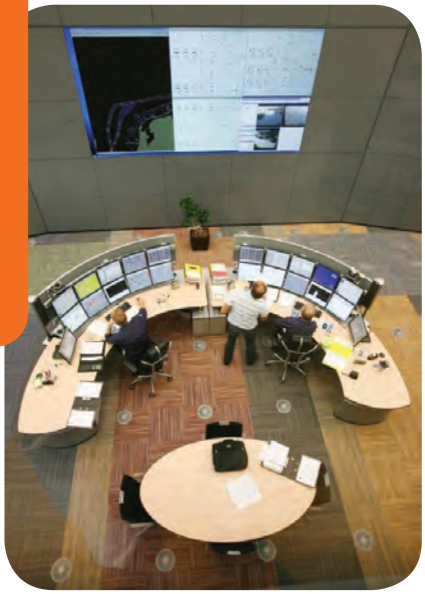


Photo from Wintershall.

Going deeper

Another aspect is with offshore going into deeper water at much higher costs and employing more subsea wells, more processing ends up conducted offshore.

"They are actually becoming much larger and more sophisticated operations, which requires more automation in order to manage them more effectively," said Randy Miller, business director for gas production, processing, pipelines, transportation, LNG and GTL for Honeywell Process Solutions. "The capital investment is so high, they actually need more automation so there is a greater return on their investment."

As a result, companies are beginning to deploy more common automation methods that you would see in refining with programs like advanced process control, optimization, operations management, and maintenance management.

"You still have the constraint of having fewer personnel on the platform, compared to an onshore operation, so you need more automation to handle that sophistication," Miller said. "You have gas processing in many cases where you are producing. I know in one case where there is a stream with a lot of carbon dioxide in the gas, and so they are doing separation using one of our purification processes to separate the CO_2, purify it enough so it can release safely. I think automation is helping make these operations viable as they get so complex."

The complexity is only going to ratchet up in the coming years and automation is the next sea change to boost production, productivity and profitability in the age of a skills shortage. **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.

Analyzing wireless machine for offshore applications

By Marty Herzog,
SKF Traditional Energy
Business Unit

There has been significant interest in wireless solutions for condition monitoring in recent years, including discussion on whether wireless technologies are a viable strategy for offshore operations in exploration and production. The word "strategy" however, may be misused. While the new technology does have benefits, it should support the existing maintenance strategy and be used as a tactic in the fulfillment of a predictive or proactive maintenance program.

Properly applied, the operational and technical benefits of wireless condition monitoring provides end-users with:

- access to equipment that has been difficult to cover by walk-around routes due the sheer number of machines.
- a means to gather machine data when health, safety or hazardous area issues make it problematic to use a portable device.
- the flexibility to deploy a temporary "online" system for a machine with a known problem rather than increasing data collection intervals with a portable system.
- a solution for applications where a wired system is impractical; for example, moving machines.
- a cost-effective alternative to permanently wired, online systems.

Thus, these benefits suggest the usage of wireless systems will likely increase in the coming years for offshore exploration and production applications.

The SKF wireless machine condition sensor collects data on three key machine conditions: temperature; overall machine condition; and rolling element bearing and has ATEX Zone 0 certification. Photo from SKF.

Wireless condition monitoring developments

Fifteen years ago, interest emerged to monitor the condition of a moving asset, such as the machining head of a metalworking machine or the axle bearings of a locomotive. Soon after, the first SKF wireless system was developed and the knowledge of how to use wireless technology in condition monitoring was enhanced. However, lack of industry standards for communications protocol and the challenges of packaging and battery life limited its applicability.

Scan this page with the Actable app on your smart phone for an overview of the SKF wireless machine condition sensor

The architecture of these first systems was limited to replacement of the wired Ethernet "backbone" of the system. The field-mounted signal acquisition system still required sensors to be wired from machine to sensors. The system manages the conversion of data to digital form and then transmits it to the host PC wirelessly. This works well and there are thousands of channels of vibration data being managed in this way. However, for the oil and gas industry-specific requirements for installation in areas with hazardous gaseous environments prohibited most applications due to the requirement for packaging of the system in expensive explosion-proof enclosures.

Meanwhile, the promise of ubiquitous, low-cost process measurement sensors operating over a wide area has fuelled massive investments by wireless technology and process measurement companies. Widespread market adoption did not initially occur due to technical issues such as proprietary protocols and installation cost barriers. With recent advances in networking, radios, processors, sensors, and power sources it is now possible to overcome these obstacles with process measurement devices. And, with the emergence of standard wireless protocols, increasingly advanced systems have been developed to offer effective wireless systems in the process measurement domain.

Compared to process measurements (scalar, overall values), vibration monitoring (dynamic data arrays) places unique demands on wireless sensors, networks and associated components: high bandwidth, good dynamic range, low noise, higher-level processing capabilities and the ability to capture data at the right time. When operating as self-contained battery powered units, the further challenge of practical service life remained. Morever, physically mounting the sensor device directly onto a machine necessitated coping with the aggressive conditions found in the industrial environment, such as exposure to water, extreme temperatures, electrical interference, hazardous area classifications, obstructions, and physical location/distance.

Recent convergence of protocol standards coupled with new wireless condition monitoring technology developments have addressed these challenges, resulting in a viable solution. Next it is necesary to consider deployment options to gain wide acceptance.

Comparing methodologies

Condition monitoring of rotating equipment is a common throughout the oil and gas industry, with the objective to detect, analyze and diagnose machinery faults. Critical machines (turbines, compressors, large motors) are normally equipped with on-line condition monitoring and protection systems. Balance-of-plant equipment (motors, pumps, fans) generally are not. Yet this machine category represents well over half of the population and consumes a significant percentage of a maintenance budget. Such machines are normally monitored manually with portable data collectors because it has been impractical or uneconomical to install a permanently wired system. However, the situation has changed with the advent of a new breed of wireless condition monitoring systems that bridges the gap between the cost wired systems and inefficiencies of portable systems.

Integrating condition monitoring and process control data

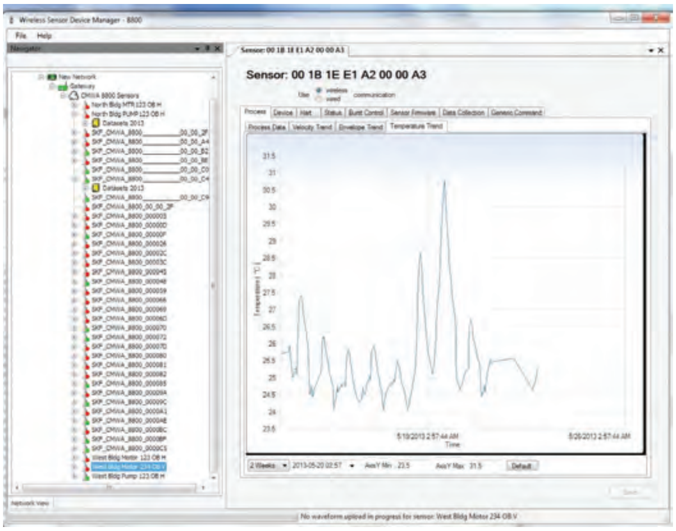
Another important development has been the ability to share data with process control systems. Changes in vibration levels may be due to a change in operating conditions, and without that knowledge an incorrect diagnosis could be costly in terms of down time and lost production output.

In the past, passing data such as temperature, flow and load, between the condition monitoring system and the process control system was time-consuming and complex, involving dedicated serial communication links and cumbersome data protocol programming. Today, the emergence of OPC (OLE for Process Control) has reduced this task to a few "click and drag" operations between networked computers. This has had a significant impact on the analyst's ability to correlate vibration changes with process conditions. All of SKF's condition monitoring software platforms can utilize OPC.

A safe solution for hazardous environments

The potential to improve efficiency through condition monitoring has driven the development of a new wireless solution. The SKF wireless machine condition sensor monitors machine components in locations that are difficult to access. It achieved ATEX Zone 0 certification, which means that it can be used in hazardous environments.

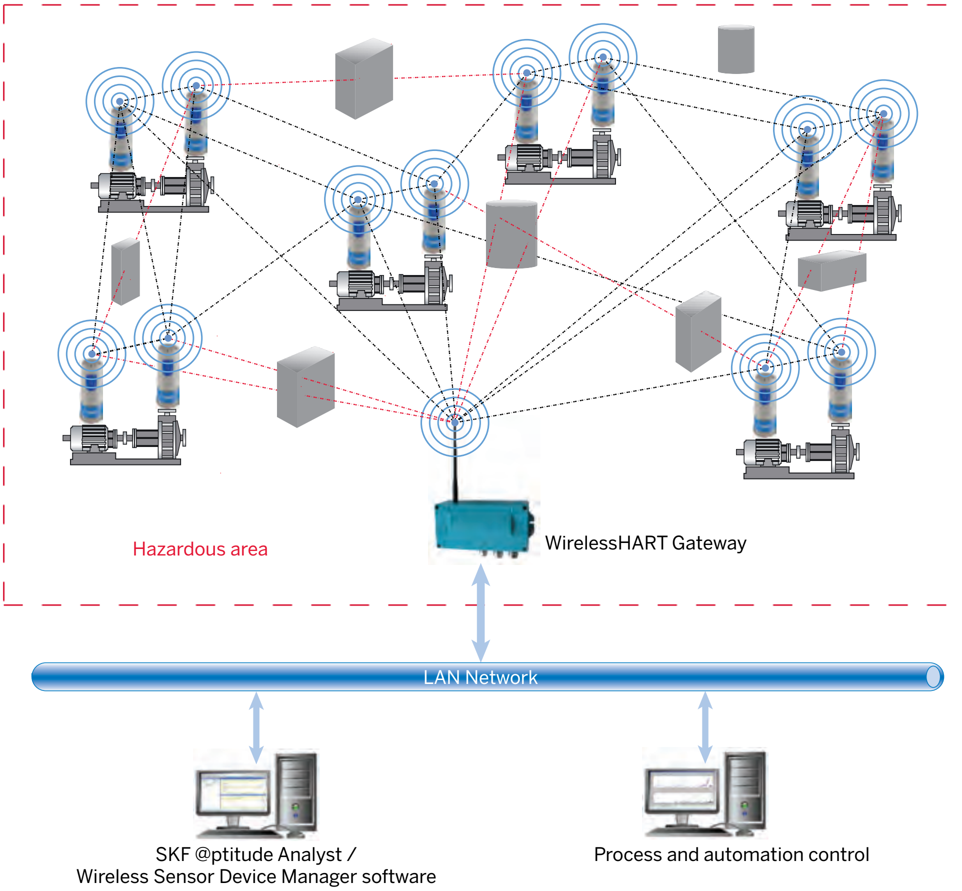
The SKF wireless machine condition sensor collects data on three key machine conditions: temperature (indicative of lubrication issues, increased friction, rubbing, etc.); overall machine condition (vibrations caused by misalignment, imbalance, mechanical looseness, etc.); and rolling element bearing condition (allows damage detection and diagnosis of source as ball / roller, cage, inner or outer raceway).



Once data is collected, the WirelessHART gateway communicates with SKF's wireless sensor device manager software.

Comparison of wireless systems

Wifi	900 MHz	Mesh Networks
▪ Uses IEEE 802.11g radio standard ▪ Commonplace in offices, hotels and homes, and well understood. It is not so common in industrial settings ▪ High data rates but high power consumption ▪ Low to moderate point-to-point range (e.g. 100m)	▪ Uses the 900 MHz public radio band ▪ No radio standard, but offered by many smaller companies using a proprietary protocol and methodology ▪ Low data rates with medium power consumption ▪ Longer point-to-point range (e.g. 300m)	▪ Uses IEEE 802.15.4 radio standard ▪ WirelessHART protocol or ISA 100.11a ▪ Early adoption phase in industrial settings (mainly oil and gas) at sensor data level ▪ Self-generating network reduces installation cost ▪ Low data rates but low power consumption ▪ Low to moderate point-to-point range (e.g. 50 – 100 m)



Mesh networks can relay data from point to point and to the gateway. Graphic from SKF.

A rough estimate for installation cost of online sensors in onshore applications can be as high as 15 times the cost of the accelerometer. For offshore installations, it can be higher than 20 to 30 times the cost of the accelerometer. The use of a wireless device could equate to an approximate saving of around $1500 per measurement point.

With this new technology, users can benefit from an improved maintenance program, reduced maintenance costs, reduced installation costs and enhanced employee and machine safety. The sensor also offers compatibility with the SKF @ptitude monitoring suite, a comprehensive software suite that integrates data from a wide range of SKF portable and online data acquisition devices.

SKF wireless machine condition sensors communicate with each other, and with a wireless gateway, creating a mesh network. This type of network and communication protocol is ideal for monitoring rotating machinery because it can function in areas where traditional WiFi communications are not present.

Communicating via a mesh network

Communication capabilities of the SKF device include relaying data from one node to another, relaying data back to the gateway, and receiving automated commands from the wireless sensor device manager software that initiates the measurement and processing circuits to take data and transmit it back over the network. If a node is unable to receive signals directly from the WirelessHART gateway, it will instead send and receive its data through a nearby node that can pass the data to and from the gateway – ultimately creating the mesh network.

Once data is collected, the WirelessHART gateway communicates with SKF's wireless sensor device manager software. Data can then be automatically exported into SKF's comprehensive diagnostic and analytic software package, where a maintenance engineer can analyze the data and determine a course of action. In parallel, the WirelessHART gateway can also send applicable data directly to the process control system for visualization and trending by operators.

Conclusion

Wireless systems will change the way we approach machine condition parameter data collection. Wireless sensors will result in much more data being acquired and, therefore, a challenge of how to analyze and manage additional data. Data reduction techniques and decision support systems have been developed to cope with this issue, thus preserving the benefit of new wireless technologies and ensuring it is supportive of maintenance strategy refinements.

Ease of deployment of wireless systems connected to process control systems will be driven by users, not by suppliers of technology solutions, and process monitoring will become more closely related to condition monitoring. The end result will be tighter integration of operating parameters and maintenance strategies where the two are adaptive to changing conditions. Eventually fully-integrated embedded sensors, using standard industrial protocols to share data, will be offered by OEMs, which will further extend the benefit of lower installation costs.

The stage has passed when early adopters installed simple systems on an experimental basis. For wireless condition monitoring, this is the end of the beginning. What engineers have been looking for is a system that is simple to install and configure, which improves on existing knowledge and allows a systemic improvement in machine reliability over a large population of machines. Data can even be analyzed remotely by maintenance engineers and the results and recommendations made available anywhere in the world where there is an internet connection. **OE**

Marty Herzog has 30 years of experience with SKF in the fields of bearing application, rotating machinery technology, condition monitoring and reliability engineering. He is currently responsible for business development and marketing for the SKF Traditional Energy Business Unit and works closely with key OEMs and end users in this sector.

Looking for Ireland's Jubilee

Exploration offshore Ireland has yet to bear significant fruit – could new ideas finally create the oil rush the region has been waiting for? Elaine Maslin takes a look.

"We are looking for the next Jubilee," Europa Oil & Gas CEO Hugh Mackay told the 2nd Annual Ireland Oil & Gas Summit in Dublin, early June.

Jubilee, a 600MMbbl field offshore Ghana, was a company-maker for Kosmos Energy and Tullow Oil when it was discovered in 2008 and brought onstream by 2011, in a fast track development.

Kosmos is now in Ireland, and Europa, one of its partners, sees similar potential in the Irish Atlantic Margin's southern Porcupine basin, based on the same play tapped by Kosmos in West Africa. Companies are also comparing features in the basin to plays offshore eastern Canada, including the Flemish Pass, where Statoil and Husky Energy have made giant finds, such as the 300-600MMbbl recoverable Bay du Nord discovery.

Kosmos and Europa see significant potential—others see it too. Kosmos, Cairn Energy, and Australia's Woodside, were new entrants to the basin last year, following the Atlantic margin-opening 2011 Licensing Round. They join a fleet of minnows, including Europa, Providence Resources, and Petrel Resources, as well as Statoil, Shell and Petronas, all hunting for Atlantic margin elephants.

Exploration to date

There is a lot of acreage to go for. Offshore Ireland is six times the size of the North Sea and its Atlantic margin area alone has a 10 billion boe yet-to-find reserves potential, Providence Resources' CEO Tony O'Reilly told the Ireland summit.

To date, however, there has been limited exploration success. There are numerous sedimentary basins, but only about 5% of them have been explored and 10% studied, David Horgan, managing director of Petrel Resources, told the same audience.

A total of 158 wells (130 exploration and 28 appraisal) have been drilled over the last 50 years, mostly in the 1970s and 1980s, and mostly in the Irish Sea, says Ciaran Ó hÓbáin, principle officer of the Petroleum Affairs Division, department of Communication, Energy and Natural Resources and Environment of the Republic of Ireland. Just 31 wells have been drilled in the Porcupine basin, and none in the Rockall basin.

There have been a handful of oil finds, but most have been classified uncommercial, according to government definitions. These include Burren (1978), Connemara (1979), and Spanish Point (1981), in the Porcupine basin.

Interest in the Porcupine basin peaked in July last year, when Dunquin North was drilled by Exxon Mobil, using the *Eirik Raude* semisubmersible. The US$200 million well—the only southern Porcupine well in 12 years—is reported to have found oil shows in a lower Cretaceous carbonate reservoir. This find proves source rock exists, potentially from the late Jurassic superhighway, connecting Newfoundland and Nova Scotia with the Atlantic margin, according to Mackay. But the find was not commercial.

Barryroe is a lower Cretaceous find in the North Celtic Sea basin

Atwood Oceanic's *Atwood Achiever* drillship, nearing completion at Daewoo Shipbuilding and Marine Engineering's yard in Korea. Photo from Atwood Oceanics.

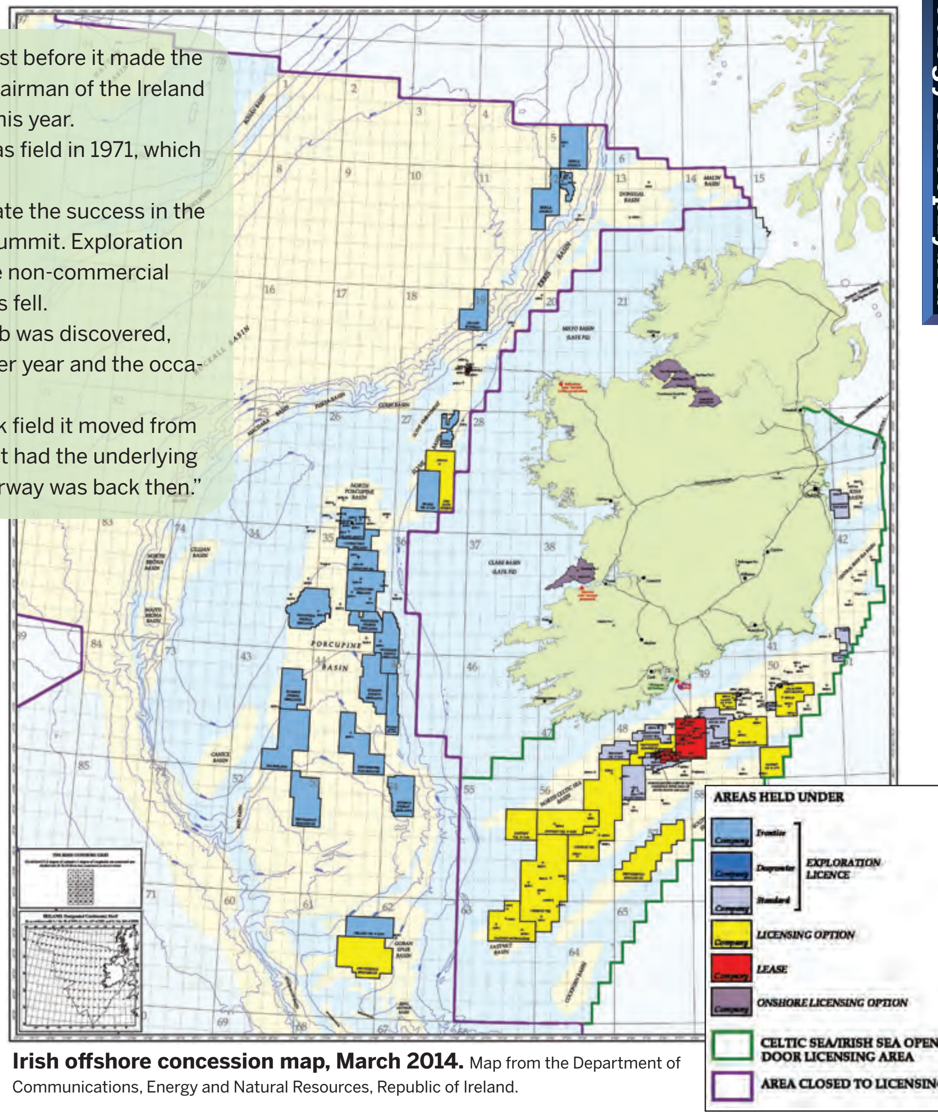
Ireland today is where Norway was in 1969, just before it made the giant Ekofisk discovery, says Fergus Cahill, chairman of the Ireland Offshore Operators Association until earlier this year.

The first discovery was the Kinsale Head gas field in 1971, which came on stream in 1978.

"Everyone thought we were going to replicate the success in the North Sea," Cahill told the Ireland Oil & Gas Summit. Exploration peaked in 1978, with 15 wells drilled and some non-commercial discoveries made. After that, exploration rates fell.

"We struggled along until 1996, when Corrib was discovered, and then we went into a pattern of 1-2 wells per year and the occasional licensing round.

"When Norway discovered the giant Ekofisk field it moved from where we are now to a world leader, because it had the underlying resource base to do so. We are now where Norway was back then."



Irish offshore concession map, March 2014. Map from the Department of Communications, Energy and Natural Resources, Republic of Ireland.

70km offshore in 80m water depth. It is Ireland's only commercial oil discovery, with an estimated >300MMboe 2C recoverable resources. Operator Providence Resources is seeking a partner to help develop Barryroe.

Production

To date, there have been three commercial gas discoveries (Corrib, Ballycotton, Kinsale Head/Seven Heads). Kinsale/Seven Heads have been producing in the Celtic Sea since the 1970s using two platforms, with Ballycotton tied in during 1991. Corrib, an 83km tie-back to shore in 350m water depth, in the Atlantic, should finally come on stream, producing 58MMcf/d at peak, in 1H 2015.

A turning point

The 2011 licensing round has been viewed as a turning point for the basin, opening for the first time the entire Atlantic, extending from about 30-380km offshore, in 200-3000m water depths. Fifty-three full blocks and 11 partial blocks, under 13 licenses were issued, to: Antrim Energy, Bluestack Energy, Europa, Petrel, Providence, San Leon Energy, Serica Energy, and Two Seas Oil & Gas.

New, bigger, entrants then farmed-in to the basin as operators: Kosmos (taking three licenses, through farm-ins with Europa and Antrim Energy) Cairn (3), and Woodside (4).

Licenses are issued as two-year license options, with no minimum work commitments, which can be converted into exploration licenses. The Celtic Sea Open Area is open for applications at any time.

Following the 2011 Round, seismic acquisition activity increased, following a 15-year lull. Ó hÓbáin says 13,000km 2D lines and 8000sq km 3D was shot last year, including a 5000sq km 3D survey by Kosmos in July-October, now being used to build a prospect inventory, on which the firm can make its 2016-17 drilling decisions.

More is planned this year. Polarcus, with GeoPartners and Ion GeoVentures will be shooting a minimum 4300sq km of 3D multi-client seismic, covering the southern Porcupine basin this year.

A major, Irish government-led 2D regional survey covering 10,000km using the BGP Explorer will also be shot over the Atlantic margin.

Porcupine play untested

Much focus is on the 60,000sq km Porcupine basin. Here, just 31 wells have been drilled since 1977, mainly by companies that have long since left the basin, due to lack of early success, Mackay says.

Europa is encouraged by the latest 3D data on the southern Porcupine basin. "We are very excited about what we are seeing," he said in Dunline, adding that there is the potential for 50-100sq km aerial extent turbidite sandstone submarine fans.

"We think there are Cretaceous turbidite fans in the southern Porcupine basin. It is an exciting new play... with the potential to hold hundreds of millions of barrels of reserves. This play has not been tested offshore Ireland yet. If it is successful we will see a complete transformation of the industry."

Kosmos has the tools to test the theory.

It has a three-year contract, starting this year, to use Atwood Oceanic's drillship *Atwood Achiever*, being completed in Korea by Daewoo Shipbuilding and Marine Engineering, with plans to drill offshore Ireland in 2016-2017.

Dunquin data key

Despite Dunquin North's lack of commerciality, Providence, which has a 16% stake in Dunquin, says it provided valuable data. "It (Dunquin North) was the first well in an area the size of the North Sea, so it is hugely important," O'Reilly says. "It wasn't commercial, but it provides a huge data point on this vast and unexplored deepwater basin."

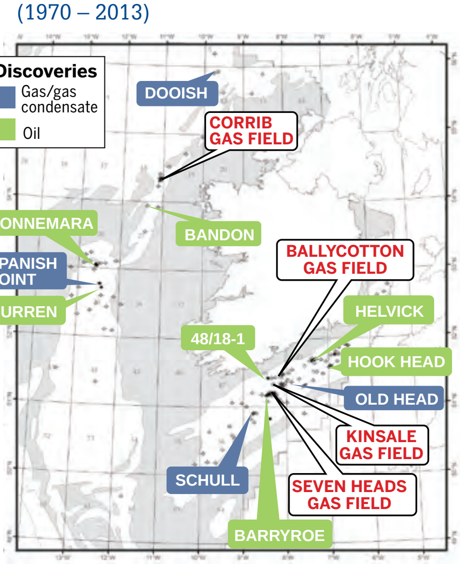
The well data have increased Providence's confidence in its Drombeg prospect (80% equity), which lies 60km southwest of Dunquin. Drombeg is a lower Cretaceous stratigraphic prospect, interpreted to be a deepwater turbidite fan system, and an estimated 3 billion bbl (P50) of oil in place, according to John O'Sullivan, Providence's technical director.

Lying in about 2.5km water depth, about 220km offshore, Drombeg has a mapped aerial extent of about 270sq km, making the Drombeg fan larger than the giant North Sea Forties field. O'Sullivan says it could contain a gassy oil, with perhaps 900MMbbl recoverable and additional potential in vertically stacked Jurassic and Paleocene stratigraphic intervals.

There is also further prospectively at Dunquin, specifically Dunquin South, O'Reilly says, given the thick, over-pressured, high-porosity, carbonate reservoir system proven in the Dunquin North well.

Key discoveries & fields

(1970 – 2013)



Source: Department of Communications, Energy and Natural Resources, Republic of Ireland.

Past problems resolved

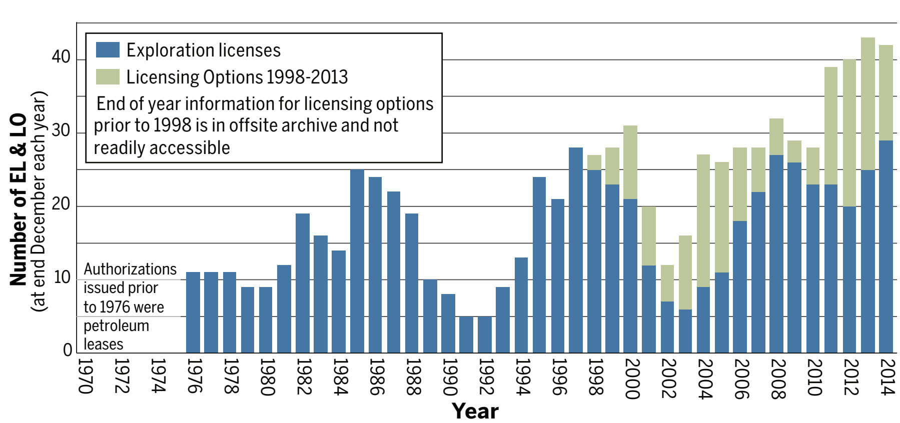
With such potential, why have no significant finds been made to date? O'Reilly says the industry previously foundered due to lack of infrastructure and accessible market.

Kinsale, brought online in the 1978, saw some infrastructure installed, on and offshore, and there is now a market for the gas in Ireland, as well as infrastructure to export it, and to land and process oil. Corrib will also bring infrastructure opportunities in the North Porcupine basin.

Mackay says the early explorers' lack of success was because they were using a Brent province geological model and the constraints of 2D seismic, and drilling rigs were unable to drill in more than 500m water depths.

There was also an assumption that the region was gas prone, making it less attractive, a view which the Barryroe discovery, successfully appraised by Providence in 2012, helped start to change. "Barryroe is important because it has probably altered the perception that Ireland is all about gas," O'Reilly says.

Number of offshore exploration licenses and licensing options at end December each year (1970 - March 2014)



Source: Department of Communications, Energy and Natural Resources, Republic of Ireland.

Barryroe

A milestone will be reached when a development concept and funding is announced for Barryroe, paving the way for commercial oil production.

Discovered in the 1970s by Marathon, Barryroe wasn't pursued due to high state participation (50% pre-1992) and an unfavorable tax regime. The oil was also waxy, which at the time had technical and economic implications, both of which are no longer a problem, O'Reilly says.

Providence is currently planning a phased development, with early production, of about 30,000bbl/d, on the eastern part of the field where most data is available, using a small wellhead platform and floating storage and offloading vessel. The development would then move to the west of the field, and additional infrastructure, with a nominal name plate of 100,000bbl/d, installed, subject to regulatory approvals. The first phase development could make use of the Seven Head manifold, which sits over Barryroe, and would be able to transport associated gas via the Kinsale infrastructure (two platforms with a pipeline to shore).

For Providence it has been a long, 30 year journey. Over 25 years, it has spent $750 million with partners exploring the Irish offshore. Over the last five years it has spent another $500 million.

The spending will continue. Work is ongoing to assess the potential to develop Spanish Point, a gas and condensate find in the northern Porcupine basin. Cairn (operator with 32% equity) is planning to drill an appraisal well on Spanish Point this year, based on new 3D data, using the *Blackford Dolphin* semisubmersible, which recently underwent a major renovation at Belfast's Harland & Wolff shipyard. "It will be the first big well west of Ireland in many years," O'Reilly says.

A critical stage

Going to press, the Irish Government launched the 2015 Atlantic Margin Oil and Gas Licensing Round, which closes September 2015. It also increased the tax on production profits to a maximum 55% (up from 40% now), and said future tax rates would be on a field by field basis. Producers will still pay 25% corporation tax. "We are at a critical stage, it'll be interesting to see what happens," says Cahill. OE

Drilling optimization offshore Sarawak

Shell reduced its Malaysian exploration well costs by 50% to make smaller and more distributed deposits of oil and gas more economic. Elaine Maslin found out more.

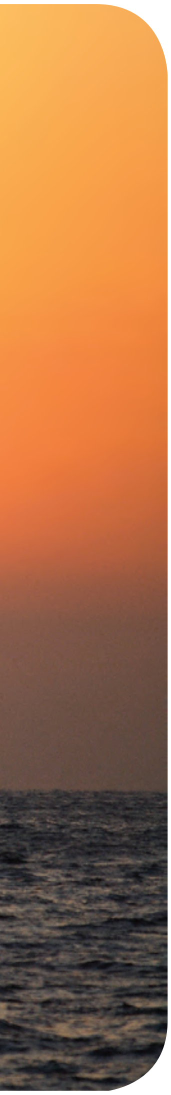
In 2012, Shell Malaysia E&P signed a new production sharing contract (PSC) with PETRONAS to explore for oil and gas off Sarawak, Borneo Island, in the South China Sea.

The SK319 PSC was the trigger for an initial three-year exploration program to explore 2727sq km within block SK319, in Central Luconia, offshore Sarawak.

The challenge in the area was to exploit smaller and more distributed volumes of oil and gas, mostly stored in carbonate pinnacles in Central Luconia, in the Sarawak basin, affordably and fast, says operator, Shell, via its subsidiary Sarawak Shell Berhad (with 50% stake in SK319, alongside PETRONAS Carigali and SapuraKencana, each with 25% interest).

Shell started exploring in the region in the 1960s, building infrastructure and hubs, into which new smaller finds could be tied. But to successfully find the smaller deposits, Shell decided to use statistics-based drilling, as employed in land drilling, which meant reducing well costs. The firm also used new technologies, including pressurized mud cap drilling, developed for carbonates in Malaysia, and casing while drilling technology. Additionally, it found better ways to collaborate internally and with contractors under a campaign approach.

The company is now about halfway through the campaign, which will be comprised of, in total, about 15 wells. The first five wells were drilled over five months, starting December 2012,



The Doo Sung rig was contracted in and brought to Shell standards to deliver the campaign. Doo Sung is Korea's only semi-submersible drilling unit, built in 1984 by Daewoo Shipbuilding Co., and owned by KNOC.
Photo from KNOC.

using Korea National Oil Company's Doo Sung semi-submersible drilling rig. The second, five-well campaign started in March this year, using a jackup drilling rig.

"Essentially, we had to drill low-cost exploration wells," says Ivan Tan, who until recently was general manager, well operations for Shell Malaysia. "Shell has been operating in Malaysia for more than 100 years. In this exploration campaign, we were targeting the remaining reserves that existed in smaller deposits in our carbonate fields. To do this, we had to find novel and innovative ways to drill the wells at a lower cost."

The Central Luconia reservoirs are mostly carbonate and what is left are smaller and more distributed volumes. About 15-20 targets were identified, but by conventional methods were deemed uneconomic or, as with seismic, not worth the cost due to their sizes.

"The strategy was to drill as many wells into these distributed pinnacles," Tan says. "But to do that we had to reduce costs. The target was simple: to cut the well costs by 50%."

The concept was initiated in about 2010, and, after signing the PSC agreement in 2012, the first tranche of exploration wells was drilled in late 2012.

"There were a number of things that underpinned the whole process," Tan said. "Good prospect selection and well design, contracting, and procurement strategies, and taking a campaign approach to the program were important elements in the campaign. Critical success factors included a lot of early integration, especially between the subsurface and the wells teams, and sitting everyone around the same table, drawing on experience together."

Contractors were brought in early and integrated into the team. In addition, the specialist teams were tasked with making operations simpler. The subsurface team, for example, only asked the wells team to acquire data that was necessary for the evaluation of the well.

Ivan Tan, Shell.
Photo from Shell.

This campaign approach allowed the teams to narrow their scope and follow fit-for-purpose standardized well designs, while questioning conventional drilling approaches. "We allowed the wells team to design a well that was fit for purpose," Tan says. "Everything was challenged and we did not accept the norm. Every conventional drilling approach was challenged and novel well designs devised."

Two key technologies were deployed—pressurized mud cap drilling, which had been developed for carbonates in Malaysia, and casing while drilling technology (CWD).

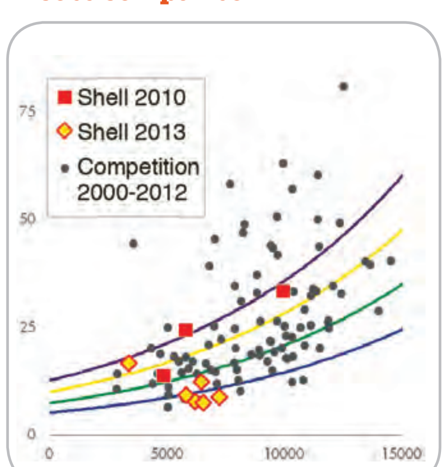
"While both have been around in the industry for a while, we combined the two and made it work for us," Tan said.

The CWD is used first, using a 9-5/8" casing size, which enabled Shell to drill and case at the same time. The well concepts on the campaign were designed around Shell's CWD concept.

During the campaign that began in 2012, the team set a record for the longest casing while drilling job. In May 2013, the 9-5/8" casing was drilled to 6255ft measured depth, or 6170ft true vertical depth subsea.

"It may not be now, but at the time we knew we were leading the pack in casing while drilling," Tan said.

Shell's Malaysian drilling cost – cost comparison.



1Q 2014 results image from Shell.

Once the casing was in place, Shell then used pressurized mud cap drilling. This is a variation of managed pressurized drilling, that involves drilling with no returns to surface and where an annulus fluid column, assisted by surface pressure, is maintained above a formation that is capable of accepting fluid and cuttings.

Tan explains that in some formations Karst losses can be encountered—a risk associated with carbonate reservoirs. This can result in drilling fluids dropping out into the reservoir, creating a risk that hydrocarbons will escape. In the past, as soon as drilling teams suspect they have encountered Karst losses, they have to abandon the well and try to drill another nearby. Using a mud cap enables the drilling team to keep a cap of mud in place so hydrocarbons don't escape during drilling. Getting the right balance of pressure is key.

The program's campaign approach, with a minimum of 5-6 wells in each campaign, also meant learnings could be incorporated. "We saw the learning come through in 2-3 wells, which meant we could build on success after success, using the same team and same contractors and equipment," Tan said. "So we had economies of scale and practice makes perfect."

There was also a "boots on the ground" ethos, to safely manage the operation and a risk-sharing ethos to contracts, so goals were aligned.

Tan says the 50% cost reduction was achieved in the first campaign. The firm has assessed its costs by comparing benchmark data held by Rushmore Reviews. This data was highlighted by Shell at its management team day (see graphic). This put Shell Malaysia in the best in class category (top 5%), based on the first six wells drilled in the campaign.

"These are probably the cheapest subsea exploration wells ever drilled by an operator worldwide on a normalized basis, according to Rushmore data," Tan said.

As the PSC operator to PETRONAS, Shell is the largest gas producer in Malaysia, accounting for 60% of the gas production. Some 90% of the gas produced is earmarked for the PETRONAS LNG complex in Bintulu. OE

Offshore drilling optimization: **Utilizing the future of technology**

By Alex Barrie, NOV

In today's oil and gas markets, there are many drilling situations in which an operator faces adversity. A growing difficulty to successfully and economically drill and produce wells has created a global demand for proper well optimization. Successful economical production of these wells requires a delicate balance between cost, performance, and risk. The oil and gas industry has a vast portfolio of available tools and technologies worldwide, with most aiming to provide new and improved information, save operators' time, and improve the well's profitability through various means of drilling optimization. The offshore markets also have additional inherent risks due to regulations and accident prevention. Utilizing existing and future technology to optimize this balance and leverage risk is the key to the next generation of drilling optimization; however, determining the correct method of optimization and required tools has historically depended on the application due to limited downhole information.

Figure 1: NOV BlackBox downhole dynamics tool. Photo from NOV.

There are many factors which lead to this drilling conservatism and inherent need for optimization, especially in today's offshore wells. As the difficulty to reach a production zone increases, so does the risk. Many times the wells that are deemed more risky to produce also inherit a more conservative performance plan by operators. For years, the oil and gas industry has been adapting and upgrading tools, but the responsibility of the well inevitably requires human interaction and decision making. Offshore drilling operators have invested millions of dollars into computerized technology and backup equipment to obtain the most precise measurements possible from surface equipment and prepare for any possible adverse downhole situations. Downhole tool configurations and bottomhole assembly (BHA) design also play a crucial role in this endeavor, yet deeper wells often take extended periods of time to transmit data back to surface, consequentially leading to a lack of knowledge of true downhole behavior at any given moment. There is a continual search for the perfectly balanced tool, one which produces high-performance data with low operator risk. How is this tool defined and who produces it?

To answer this search for the best drilling tool for well optimization, several aspects must be considered that highlight the future of the oil and gas industry, especially in offshore well production. Today's drilling operators consider four main variables in drilling performance tools: speed, consistency, precision, and reliability, all at the lowest cost to increase production margins. Within these categories is the key to drilling optimization: A driller must have both the quality of data and quantity of data to make an informed decision. This comes with a caveat, as either of these variables alone is useless if it is not delivered quickly enough to surface for the driller to interpret. This adds increasing merit to the adoption of today's technology into the industry.

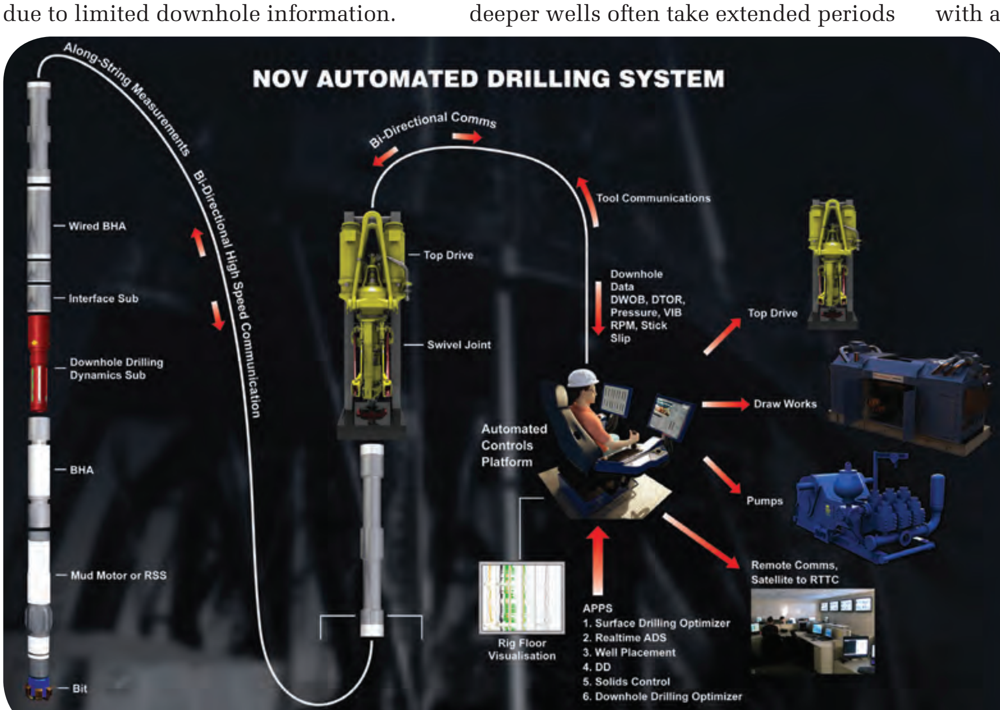


Figure 2: Automated drilling system components. Image from NOV.

The oil and gas industry has traditionally been slow to adapt to changes in technology, which will only be more scrutinized as the industry's generation gap settles. There is a massive amount of experience leaving the industry, and the younger generation will rely more than ever on technology to capture, save, and utilize this information to bridge the knowledge gap in drilling. The most important aspect of this "crew change" will be the change in mindset, allowing the industry to progress its drilling optimization practices using digital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technology and computer-controlled equipment as an aid to experience.

Because so many factors contribute to drilling optimization, a single tool would not alleviate the needs of the industry. Instead, a shift in the mindset of drilling practices toward using technology to facilitate decision making is a solution to the industry's drilling optimization needs. The main catalyst driving this is technology integration.

As with other industries, operators will soon be faced with the "big data" situation—having the ability to visualize situations as they occur from various sensors integrated into drilling equipment both at surface and downhole. What can these sensors show, and how will they benefit today's operators? The answer is a tiered approach, beginning with well planning and continuing through production, with each tier using these sensors in a related manner.

There are various tools and drilling optimization solutions available in the market to complement this new tiered drilling mentality. First and foremost, there is proper well planning (survey data, formation expectations, and directional planning), which is the first step toward using downhole technology to increase performance and safety. Next, there is the ability to create a drilling roadmap, which is fully optimized for a particular region or series of wells. When establishing a pad to drill several wells, the operator typically drills the first well using only survey information. A drilling optimization tool (or series of tools in various locations in the BHA or string) such as National Oilwell Varco's BlackBox memory tools (Figure 1) can record drilling dynamics data at a high frequency, as it occurs. This not only provides the driller with valuable post-well drilling information, but also allows a drilling roadmap for the remainder of the pad. This roadmap can offer previously unknown details about the formation, reactive vibration and torque, and downhole weight transfer, providing the driller with faster, more reliable performance going forward.

High-speed data telemetry with wired drillpipe supporting real-time downhole tools is at the top level of drilling optimization. When compared to traditional mud pulse measurement-while-drilling tools, real-time drilling data feedback can provide information to the surface at the fastest rate and highest quality possible, allowing the driller to visualize drilling reactions to the preplanned drilling roadmap. This also allows for understanding of real-time energy loss based on the downhole data versus surface data comparison.

Several wells have been drilled using National Oilwell Varco's BlackStream downhole drilling dynamics tools in collaboration with IntelliServ wired drillpipe. While similar to the BlackBox memory tools in data acquired, the BlackStream downhole tools connect to wired drillpipe for real-time telemetry. Over the course of several wells, the BlackStream tools provided an increase in both consistency and performance. An illustration of the automated drilling system and components can be seen in Figure 2, showing the downhole tool and its connection to the surface data acquisition system.

The automated drilling system has several advantages with respect to drilling optimization. By itself, the system allowed the driller to clearly view downhole behaviors as they occurred while drilling. These behaviors allowed the driller to measure torque transfer and multiple types of vibration that were contributing to energy loss along the drillstring and BHA. While surface weight values were held relatively steady by using an autodriller, downhole weight values were very unpredictable and frequently oscillated above 50% of set point values on the wells drilled (SPE).

In addition to the driller's ability to view downhole data, applications can also be implemented that connect to both downhole data and surface data, allowing for automated drilling. This application was activated on the surface data acquisition system during drilling and was able to collect downhole and surface data, acting as a "smart" downhole autodriller. This application used the data streaming to surface from the NOV BlackStream tools to calculate the most efficient operating values for various drilling equipment, keeping the downhole behavior consistent and predictable. This consistency reduced the risk of tool failures while allowing for increased drilling performance and vibration consistency for the entirety of the well. Most importantly, this combination of tools and software led to increased reliability and safety.

With the increase of drilling hardware and software competition, tools must be properly chosen per application. Each tool has a specific purpose, and with the advent of real-time data telemetry to surface, it quickly becomes apparent which BHA combination is the most optimal. In the race to improve drilling performance and safety, consistency is winning. Sometimes less is more, and the key is finding the correct window of downhole weight, differential pressure, and rotations per minute (RPM) by trusting technology and software to guide and teach during the drilling process. A human may be able to make a single decision before a computer, but the long-term alert and automated damage mitigation of a proper data acquisition system will continually outperform a human in both speed and consistency.

Because the oil and gas industry has historically lagged other industries in regards to cutting-edge technology applications, there has been a growing separation between the oil and gas industry and other sectors in the race to computer-optimized performance and safety. This separation is rapidly decreasing, thanks to the advancement of technological oilfield equipment. There are increasing opportunities and growing excitement for improved offshore drilling techniques, but they will only become effective with the supporting mindset in the field and our willingness to trust in technology. **OE**

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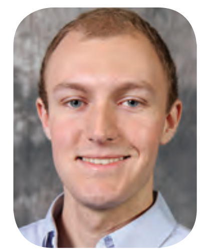


__Alex Barrie__ is product line champion for BlackBox tools at National Oilwell Varco, based in Houston. He manages the development and sustainability of drilling dynamics memory tools and is a subject matter expert of the product line. Previously, he worked with various groups collecting data from real-time automation tools, publishing and presenting the drilling optimization results to the oil and gas industry. Barrie earned a BS in mechanical engineering at Texas Tech University.

Babcock beefs up

Babcock's site at Rosyth. Photo from Babcock.

Babcock has its eyes on growth in the offshore upstream sector, including FPSOs and small topsides, after cutting its teeth on its first major project. Elaine Maslin paid a visit to the firm's busy Energy and Marine Services team at their Rosyth facilities in Fife, Scotland.

Like a number of shipyards in the UK, the Rosyth site is a former naval yard. It is now part of Babcock International Group, and is not only the site where the UK's largest warships are currently being assembled, but also structures for the oil and gas industry.

After a number of years outside oil and gas, the business scooped a contract for 73 subsea structures with BP. More recently, and while still completing the project for BP, it won a contract for a 160-tonne manifold for Total's North Sea Grant and Ellon development, due for delivery in 3Q 2014, as well as work on Bibby Offshore's vessel, *Bibby Polaris,* and engineering and design work on a walk to work platform.

The facilities at Rosyth have 27 fabrication/construction bays covering 27,000sq m, four main assembly bays and four paint shops, two of which were newly-built to accommodate the BP Quad 204 project (OE: July 2013).

To accommodate the Quad 204 project, Babcock carried out significant upgrades at the site, widening and heightening bay doors and installing one-two, new, 10-50-tonne cranes in most of the workshops. The site also has 40,000sq ft storage space, two, self-propelled transporters, and mobile cranes up to 250-tonne. Rosyth also has a 1000-tonne capacity Goliath crane. Load-out areas are certified up to 1.5-tonne/sq m.

"We saw a massive opportunity for opening the business up, to be one of the major integrators," David Goodfellow, Babcock project director, oil and gas, said. "I don't think there is a fabrication bay that has not been upgraded. BP

Two SSIVs in a fabrication bay.

The M71 manifold near completion.

Photos from BP, by Mathieu Buckley.

Quad 204 allowed us to demonstrate that capability."

Babcock won the contract to fabricate 73 structures for the Quad 204 redevelopment in December 2012. The total order is comprised of 73 structures, weighing 15-150-tonne each (or 2500-tonne in total), including 30 flowline termination assemblies (FTA), 14 controls distribution assemblies (CDA), seven riser end terminations (RET), ten umbilical end terminations (UET), three subsea isolation valves (SSIVs), and two dynamic umbilical termination assemblies (DUTA), with the remaining structures comprising various size and complexity manifolds, Goodfellow said. For BP, it was an opportunity. "What we saw initially was an opportunity for Babcock to create a site capable of large scale fabrication of subsea structures with an ability to perform system site integration testing in one location and the benefit of performing all this work undercover in a controlled environment," Sandy Meldrum, BP Subsea Structures Project Manager, said. "Civil upgrades performed on the site has provided exactly the facilities that meet our needs for a large scale and complex project such as Quad 204. Having all the structures built at one site meant they didn't need multiple teams going out to do integrity testing," he added.

"The structures consist of equipment we have purchased from a lot of suppliers—Verderg, Aker Solutions, Bel Valves, HPF Energy Services, Oliver Valves, Cameron," John Ibbotson, BP lead project engineer, System Integration Testing, said, all of which makes working closely crucial. A lot of free-issue kit was ordered, geared around trying to get ahead of the game, Meldrum adds.Fabrication started in May 2013, as decommissioning work on the old *Schiehallion* FPSO and some of its existing subsea structure was underway offshore. The nature of the order meant that, after the first five structures started fabrication, Babcock was able to review its fabrication process and initiate lean manufacturing processes, creating production lines, instead of each structure being built individually, Goodfellow said. "We modified some of the build strategy based on lessons learned, particularly where we had more than one build, resulting in an assembly line environment," he said.

This year will see the 30 FTAs, SSIVs, UETs, and a number of manifolds delivered, with remainder, including some of the more complex modules, due to be delivered before 1Q 2015. Smaller structures will be transported by road to where they will be loaded out for installation. Larger structures will be loaded out onto vessels at Rosyth, in the Firth of Forth.

In May, factory acceptance testing and system integration testing was under way in one of the yard's 27 covered workshops, ready for load out. The first of the structures loaded out in the first week of May. They will be installed offshore West of Shetland, between July and September, as part of a two-year installation campaign, handled by Technip, culminating in hook-up and commissioning, with first production scheduled for the end of 2016, Meldrum said.

Further projects are already lining up. Work has already started on the Grant and Ellon development manifold and Babcock is bidding for more work with a number of North Sea players, as well as eyeing the potential for work destined for Norwegian waters.

Subsea structures are just the start, Goodfellow added.

"We are keen to look at some of the smaller topsides as well, to get us off the seabed." Likewise, FPSOs could be brought in for topside conversion—a medium-long term focus for Babcock. In fact Babcock was involved in the marine side of the recent Haewene Brim project in Nigg, near Inverness.

"Babcock aspires to be a player involved in more detailed scope including engineering, design and procurement," Goodfellow said. "We integrate very complex structures and have done so for many years." **OE**

The Quad 204 is a major subsea redevelopment project, involving the redevelopment of the Schiehallion and Loyal fields, to the west of Shetland on the UK Continental Shelf.

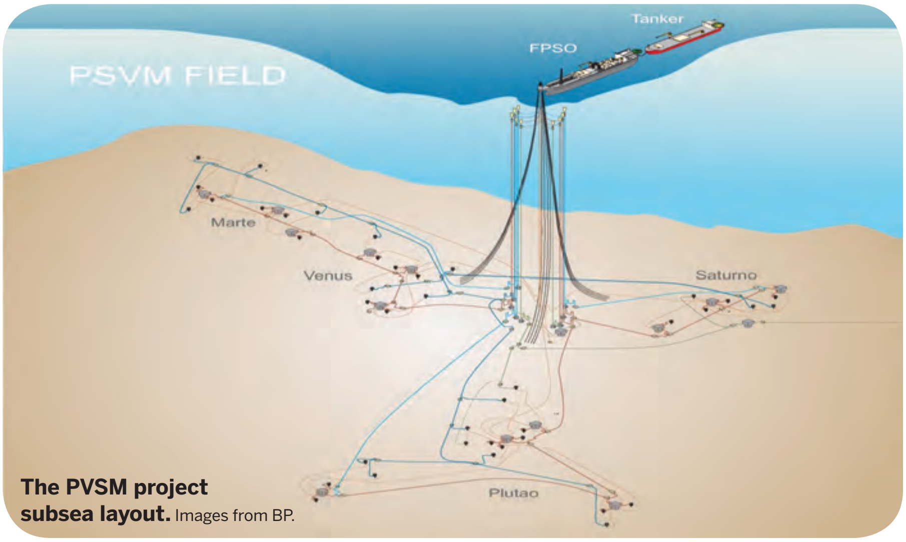
The *Schiehallion* FPSO has been moored in 400m water depth, 281km (175mi) west of Shetland, producing oil from the Schiehallion and Loyal fields since 1998. The reservoir sits 2000m below the seabed, covering about 194sq km (75sq mi).

As a result of new exploration activity and technological developments, recoverable reserves are now known to be more than double the original estimates.

The original development had expanded to 51 wells in five subsea drill centers. The Quad 204 redevelopment is adding an additional 25 wells, replacing the existing FPSO with a newbuild on the same location, re-using existing subsea infrastructure where practicable, and replacing it where required and extending it as required to support additional wells. ▪

BP's Field of the Future program has been put into action on the PSVM development offshore Angola. Elaine Maslin reports.

Intelligent energy in action



The PVSM project subsea layout. Images from BP.

BP's deepwater PVSM project offshore Angola is an example of intelligent energy in action, said BP region president, Angola, Martyn Morris.

The project, standing for the Plutão, Saturno, Vénus, and Marte fields, came on stream last year, about 400km north west of Luanda in 2000m water depth. The subsea infrastructure is one of the largest layouts in the industry in deep water, at 38km x 18km-wide and comprising 77,000-tonne of seafloor hardware. At least 40 production, gas and water injection wells will eventually be connected to the FPSO through 15 subsea manifolds and associated subsea equipment.

When BP was working on the development, it decided to make an example of it, using new technology where it could, drawing on BP Field of the Future program, launched in 2001, Morris said. BP describes Field of the Future as harnessing the opportunities created by the latest digital techniques to deliver benefits in operating efficiency and recovery.

The program itself is underpinned by the linking of BP's operations in Angola to 35 Advanced Collaborative Environments (ACEs) worldwide, accessing real-time data about its reservoirs and operations. Currently the data comes from offshore, through satellite links, although BP is looking towards a fiber optic solution.

"As part of the Field of the Future program, we put all the bells and whistles into the PSVM facility," Morris told the SPE Intelligent Energy Conference in Utrecht in April. "We decided to put in as much of this technology as we could. It is about putting in equipment to calculate real-time data. We talk about the field of the future, but this is the field of the future, today."

PSVM is in Block 31, in the prolific lower Congo basin offshore Angola. The *PSVM* floating production vessel (FPSO), is a 385m-long, converted very large crude carrier, able to store up to 1.8MMbo, located in the north east sector of the block. The development comprises 17 subsea wells, producing from the Plutão, Saturno, Vénus, and Marte fields.

All four fields were discovered between 2002 and 2004. The reservoirs are 1400m-deep, turbidite unconsolidated sandstone with high permeability.

Initial production was from three wells located in the Plutão field, with additional production coming online during 2013 and 2014.

MODEC supplied the *PSVM* FPSO, under an engineering, procurement, construction and installation contract with BP. BP Exploration (Angola) is operator on Block 31, holding 26.67%, with partners Sonangol P&P (45%), Statoil Angola (13.33%), and SSI 31 (15%). Sonangol EP is the concessionaire.


BP's *PSVM* FPSO.
Photo from BP.

The technology

A key concept on the field has been enabling information from technologies used to be connected back to offices in Luanda, where it is then fed into an the ACE, which links the onshore team, offshore team, and any other offices required, such as Houston or Sunbury (UK), into the working environment. By doing so, BP can draw on its global experts to manage anything from drilling to subsea sand detection, and flow control.

Feeding into the ACE is information from an array of technologies. Remotely operated vehicles are used to fly along flowlines, collect subsea samples, and position subsea acoustic monitors, to monitor wells.

"Every single well we have has a multiphase flow meter," Morris said. "This helps calibrate the integrated surveillance information system, which allows us to calibrate and check all the dynamic data we are bringing in."

Downhole flow control is used for water injection management, and tracers are used on most water injection wells and three gas injection wells. Subsea sand detectors for integrity management and an integrated subsurface information system has been deployed with alerts, rate and phase, well test, and ARPE modules. A subsea acoustic monitoring system was used to carry out interference testing.

4D seismic will also be deployed on PVSM. BP will carry out its first time lapse survey in 2014, 18 months after production started in December 2012. Using specialist vessels, it will shoot new surveys every 18-months to two years and use its own proprietary software to analyze the data. Data collected will be combined with production logging tools to track water movement through the reservoir, and to see where oil remains. This will help increase recovery 16-18% by identifying opportunities and drilling new wells, Morris said.

Slugging

One of the biggest risks on PSVM was during start up, specifically around slugging. A slug controller was developed, which provided significant benefit on start-up for the Saturno field, which sits some 15km from the Plutonio, at the center of the development.

The slug controller's role was to stop production oil and gas backing on itself in the 12in. riser, which travels up through the 2000m water depth. A riser with oil and gas can get unstable. The slug controller uses algorithms, based on pressure, temperature, and flow data, to work out the volume of oil, based on weight, in the riser, and actuates the inlet valve (riser top control valve) accordingly, so there are not huge variations in inlet pressure.

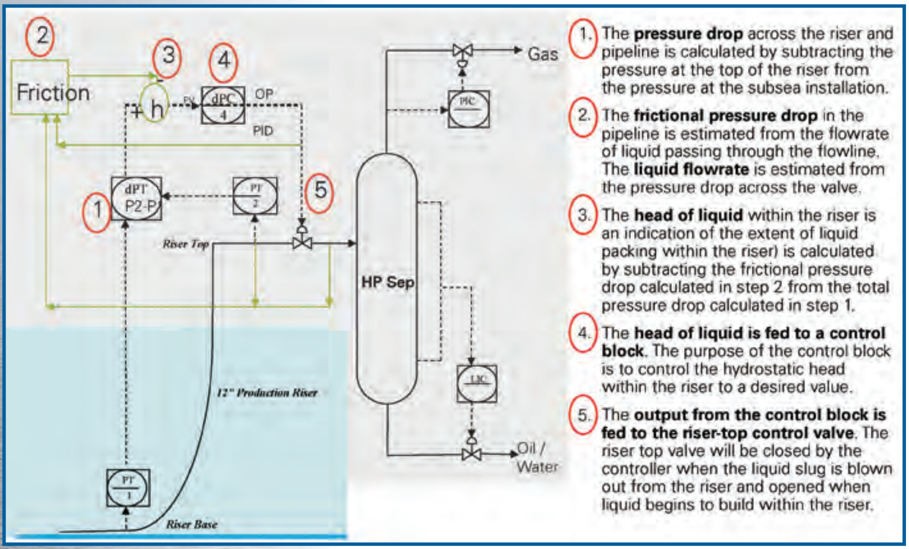
"If you have a slug coming up the riser, it is important you do not let the fluid in too quickly," Morris said. "It can cause vibration at the bottom of the riser and huge fluctuations in pressure and you can end up tripping the plant on high pressure trips."

The technology was developed with Cranfield University in the UK before being trialed on the Valhal field, off Norway.

"Without this we would not have been able to start up the Saturno field, due to the distance of the field from the FPSO and the depth and topography of the seabed," Morris said.

PSVM sits in Block 31 offshore Angola.

BP's solution for severe slugging



Start of a digital era

During field startup at the end of 2012, using the ACE, staff from Sunbury, Houston, Angola, and the offshore team were brought together 24-hours/d for the first week, bringing in experts who would not have been able to be on location and would still be available to other teams. Production ramped up to 75,000boe/d without much problem, Morris said.

"The digital oilfield is here," he said. "Real-time data is available, and there is lots of it. The trick is knowing what to analyze, what to use, and when to take action."

"There is some more work to be done," he told OE. "My feeling is that the next step-change will be having machines doing basic analysis, advising you where issues are potentially arising or have arisen, then you take action. The more instrumentation you have, the more maintenance it requires, and it can break and go wrong, and, if you are not looking, you might miss something. We have to help ourselves get smarter; it's business transformation. You have to have your organization working in a way that you can use the data and that requires leadership—the executive team, the COO—to be enlightened by the technical team."

The future

Nineteen discoveries in Block 31 have been announced to date. Future development is expected to be comprised of multiple hubs similar to the first development (PSVM). The second development for the southeast area of Block 31 is in the planning phase. **OE**

Inflatable seals for critical offshore applications

Bruno Rouchouze and Cindy Krishna, of Technetics Group, discuss the mechanics of inflatable seals and their applications.

Inflatable sealing technology is used in a number of critical applications including offshore production, storage and offloading (FPSO); anchoring drill rigs to the seabed; gas loading systems; pipeline welding; and watertight doors and panels.

Inflatable seals are the safest and easiest method of sealing components that move in relation to one another, and are frequently connected and disconnected. Capable of adapting to varying environmental and service conditions, these type seals can be expanded and contracted pneumatically or hydraulically to accommodate these changes.

The seals are available in different materials and high- and low-pressure configurations based on elongation and deformation of their profiles. Their hollow-molded shapes maintain consistency during expansion, conforming to the dimensions of the mating surface (Figure 1).

Inflatable seals can withstand a wide range of temperatures and pressures, providing a tight, durable and elastic solution to protect and keep equipment functioning during demanding drilling operations.

Figure 1: Inflatable seals.
Images from Technetics Group.

Background

Sealing critical applications in demanding environments used to be done with solid rubber profiles, which required extremely high compressive loads to seal effectively. They also required perfect machining of mating surfaces, since solid rubber is not sufficiently compressible to compensate for any irregularities or deformation that could pose potential leak paths. This machining is an expensive process, and not always possible.

The clearances to be sealed in any application can vary widely. A door or panel can have very different gaps to compensate for from one side to the other, i.e. a 2-3mm gap in one place and one much larger elsewhere. To close the widest gap, a very large load would have to be applied to a compact seal, over-stressing the main part of it in the process. An inflatable seal, by contrast, requires virtually no effort, since there is no contact during closing and expands to fill any gaps afterward.

To accommodate these variations, inflatable seals come in high-pressure and low-pressure configurations. The operating principal of high-pressure seals is elongation of the lateral faces of a squarish profile cross-section (Figure 2).

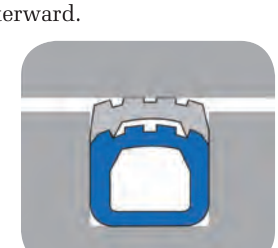


Figure 2: High-pressure seal profile

High-pressure inflatable seals are designed to fit in metal retaining grooves, allowing axial, external radial and internal radial expansion, These seals typically can withstand pressures of up to 8 bar, and are suitable for sealing clearances from 2-10mm.

Low-pressure seals work by geometric deformation of an omega-shaped profile (Figure 3).

Capable of handling external pressures up to 2.5 bar, they can be expanded 5-30mm to seal larger clearances.

Both types of seals can be inflated with compressed air or nitrogen, which will slowly leak through the material, necessitating occasional re-inflation. They also can be inflated with liquids such as water or oil, which will not leak through the seals, but will reduce their compressibility.

If the primary function is to provide sealing, it is advisable to use low-pressure, air- or gas-filled seals, which also provide better insulation and sound and vibration damping. If the function is to lift or lock something in place, a harder, liquid-filled seal is recommended.

For valves, molded cones provide better sealing, since the profile around the valve and the overall profile are molded in one piece, rather than fused together (Figure 4).

This precludes any areas of weakness or potential leakage. The valve therefore has greater damage resistance and good centering. Also available are expandable end plugs and end plug fixing devices.

The latter are used with flanges or retaining plates to avoid damaging seals during inflation, and to ensure they remain in the grooves when the seals are deflated.

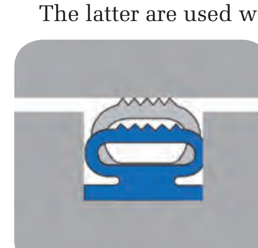


Figure 3: Low-pressure seal profile

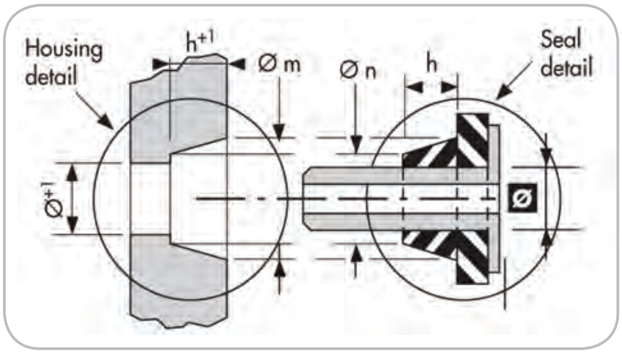


Figure 4: Molded cone profile

Deflatable seals

An important advance in inflatable seals is their ability to operate with either pressure or vacuum. This allows them to be deflated, for example, when a watertight door is opened. Even if there is no internal pressure remaining, they will seal a door tightly when it is closed. The seals can also be re-inflated to atmospheric pressure or more if stormy weather conditions are anticipated.

Inflatable seals are available in a wide range of extruded, molded and profiled materials to meet the requirements of diverse applications. Silicone rubber (Q) has good thermal properties, remaining stable in terms of compressibility across a wide temperature range (-30°C to +100°C and up to 250°C for short durations). Being mineral-based, it has better aging properties and UV resistance than organic materials, which can oxidize in air and degrade with exposure to UV radiation. However, it is not a particularly robust material, with little abrasion resistance.

Nitrile rubber (NBR) is impervious to oil and some other hydrocarbons and temperatures of up to +100°C (+150°C for hydrogenated nitrile rubber or HNBR). Neoprene rubber (CR) is fire-resistant and has good aging properties, but is limited in temperature capability (0°C to +100°C). Styrene butadiene rubber (SBR) is less permeable than silicone, and is seawater-resistant. It has good tear and abrasion resistance, and a temperature range of -20°C to +100°C.

Fluorocarbon rubber (FKM) has low permeability, and can withstand contact with oil or gas, but is quite expensive. Fluorosilicone rubber (FMQ) is a fragile and expensive material, used primarily to seal aromatic applications such as kerosene and other fuels, making it suitable for certain oil and gas applications.

Applications

Inflatable seals are being used successfully in a number of oil and gas applications. For example, large-diameter seals are used in the connection between the riser buoy and ship turret for a rig working off the coast of Greenland (Figure 5).

Twenty meters in diameter, soft, low-pressure seals made of SBR material are inflated with air, allowing them to be squeezed without damage by wave action between the buoy and ship. The temperature is 10°C, and the seal is submerged to a depth of 30m.

Another application is anchoring offshore platforms to the sea floor (Figure 6).

In this application, the pressure of an 800m water column embeds a pipe anchor in the seabed. Inflatable seals that function independently of the water depth create a differential pressure when installing or pulling up the anchor. This application also features low-pressure SBR seals, 5m in diameter.

A single seal provides a pressure barrier of 2.5bars, but when two or three seals are installed in parallel from the outside to the inside of the anchor, 10 bars of pressure can be achieved.

In addition, FKM seals inflated with oil, water or gas are used to seal toluene and benzene vapors in gas loading systems (one major producer uses silicone rubber seals that are impervious to vapors and protected against high- and low-pressure extremes).

Inflatable silicone rubber seals also are used to seal neutral gas areas in inert gas chambers for pipeline welding, as well as in devices for testing welded parts. In these applications, the seals are inflated with nitrogen gas, leaks of which will not pose a welding hazard.

Conclusion

Inflatable seals make it possible to

Figure 5: FPSO application

overcome difficult challenges. They can be used in a wide range of applications, including buoyancy-aided sealing, gas containment, and clamping/unclamping. Among their principal advantages are flexibility in profiles, compounds, working loads and operating environments, i.e. the level of sealing and flexibility in extreme conditions including availability of custom seals for special applications. Inflatable seals minimize open/close stresses, and provide pressure and vacuum capabilities, a broad temperature range (-30ºC to +250ºC), large selection of materials, and configurations for valves and flanges. **OE**

Figure 6: Anchoring drill rigs to the sea floor.

__Bruno Rouchouze__ is a senior product manager with the Technetics Group, a unit of EnPro Industries, Inc. Based Montbrison, France, he has been with the company 34 years, where he has been involved in the design and development of inflatable seals and rubber sealing devices. He is a graduate of the Universities of Saint-Etienne and Montpelier.

__Cindy Krishna__ is senior oil and gas market manager with the Technetics Group based in the UK. Previously she worked for Emerson in instrumentation products management for 17 years. For the past 10 years she has focused on the oil and gas market, including control valves, subsea equipment installation and FPSOs. She is a chartered engineer and holds a Master's degree in engineering and an MBA from the University of Liverpool.

A heavy challenge

Work on the Bentley heavy oil field in the North Sea showed the significance of experimental data when unconventional fluids are expected to be transported through pipelines. Christian Chauvet explains.

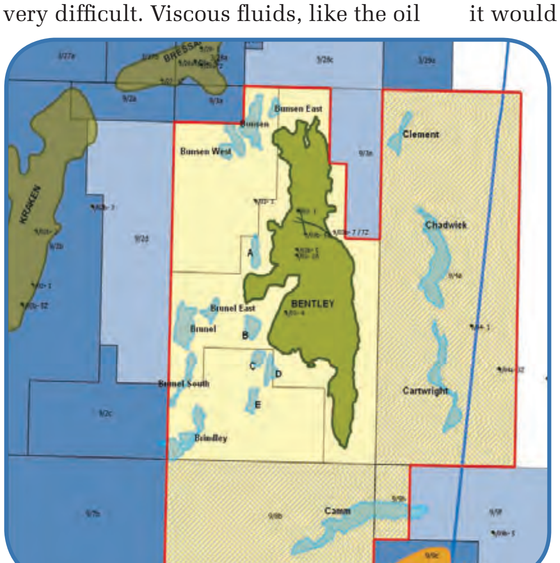
Wood Group Kenny's (WGK) flow assurance team was involved in the preparation for the extended well test (EWT) of wells 9/3b-7 and 7Z in the North Sea Bentley field, performed between July and September 2012.

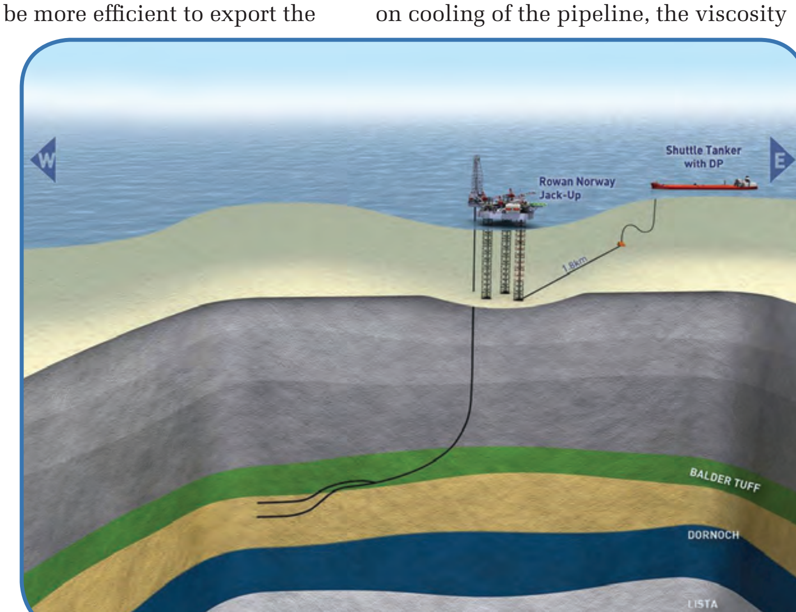
The scope of work was to design the export pipeline to ensure that the processed oil would be exported safely and efficiently from the Rowan Norway jackup drilling rig topside facilities to the tanker, *Scott Spirit*.

The Bentley field, operated by Xcite Energy Resources, is in North Sea Block 9/3b, 160km east of the Shetland Islands. The entire field is estimated to contain about 900MM stock tank barrels of oil with an American Petroleum Institute (API) gravity between 10° and 12°. The crude remains mobile under planned operating conditions, however, if allowed to reach ambient pressure and temperature, the viscosity of the oil would be too high to allow practical flow.

The challenges of transporting such a fluid through a pipeline are obvious, but, in addition, the lack of information from analogues, prior to the EWT, made the modeling and predictions very difficult. Viscous fluids, like the oil from the Bentley field, do not behave like conventional oil during transport, especially when they are cooling down. In a cross section of fluid, a steep gradient of temperature can be observed. This change in temperature is accompanied with a significant change in the fluid viscosity, hence the transport properties. Such fluctuations of behavior make the modeling of the transportation with the standard one-dimensional or more complex computer simulation tools very challenging. It is possible to take such properties into account, but the modeling in this case relied heavily on accurate laboratory-derived empirical data in order to calibrate the numerical model.

For operational reasons, a 2.1-km, 6-in. Manuli flexible rubber pipe was selected to transport the fluid. The initial flow assurance analysis focused on the heat conservation through the system in order to keep the fluid temperature as high as possible and a minimum level of flow, to retain heat, thus reducing the pressure drop. It was anticipated that it would be possible to export the processed oil without the help of a carrier fluid. Although the analysis showed that it would be possible, operating reasons indicated that it would be more efficient to export the oil with a carrier fluid, such as filtered seawater. The main reason for this was that in case of an unplanned shutdown, it would be very difficult to recover flowing conditions in the pipe. If the carrier fluid was not used, there was a danger that on cooling of the pipeline, the viscosity





Above – The Bentley field. Right – The extended well test set up. Images from Wood Group Kenny.

Drill floor operations on the Rowan Norway. Image from Xcite Energy.

of the fluid would increase significantly and the pressure required to restart the pipeline would be higher than the design specifications of the pipe.

The presence of the carrier fluid changed the modeling approach. The flow pattern generated in the pipe by mixing the seawater with the processed oil through the export would have a strong effect on the behavior of the fluid throughout the pipe: Would both fluids stay separated; would they form a fully-mixed fluid or a very tight emulsion? Each possibility was investigated prior to the flow test. The flow pattern would significantly influence the pressure drop and heat conservation. The modeling relied exclusively on the laboratory data as, there was limited information available in the literature. A full operating envelope was defined prior to the EWT.

WGK also assisted Xcite Energy during the EWT. The first data coming from the drilling rig and tanker indicated that there was a poor match between the model and the measured parameters. Even if the expected arrival fluid temperature was within the range of accuracy of the model, the pressure drop observed was significantly lower than predicted by the model. Therefore the modeling approach had to be re-evaluated.

Comparisons of the fluid clarity in samples taken at both ends of the pipe indicated that the pipeline was acting as a separator. The inlet topside samples showed a fully-mixed emulsified brown fluid, while the tanker samples showed clear separation between the phases, with clear water and black oil. However, oil and water flow measurements showed there was no differential hold up of any crude oil in the pipeline.

In-depth analysis of the data provided by the flow test showed interesting results—the pressure drop observed was slightly above that if the fluid was pure water, but much lower than if dry oil or oil emulsions were flowing down the pipeline.

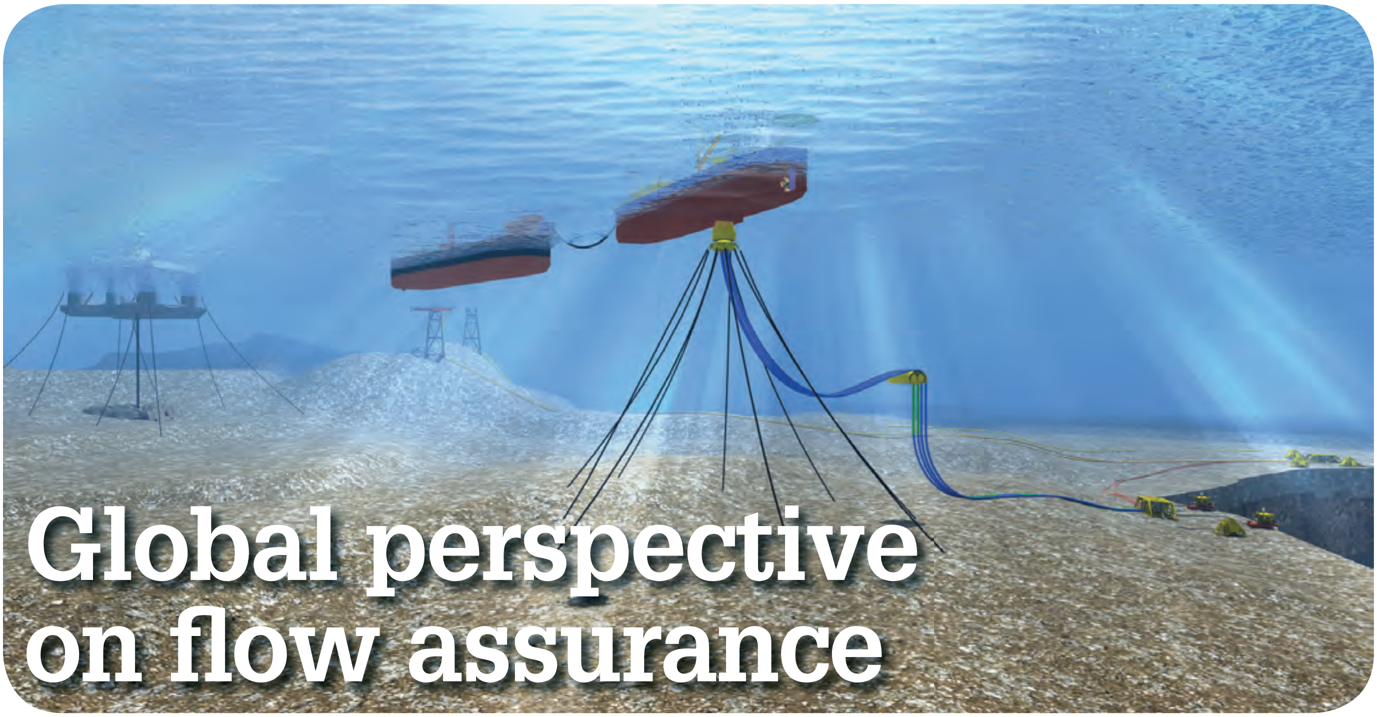
An initial hypothesis was based on the fact that the shear generated by the export pump was not sufficient to create a stable emulsion. Therefore, the flow pattern could be anything between a tight stable emulsion and two fluids being fully separated. It would be possible that the pump would disperse the oil into small droplets that would be carried by the seawater. Unless enough water was in the pipe to fully surround the oil droplets, the overall viscosity of the fluid would be high. However, when a minimum volume fraction of water is reached, the pressure drop would decrease significantly. But, this is inconsistent with the low pressure drop experienced for water cut points above 20% and therefore an alternative hypothesis was sought.

The second hypothesis is that the pipeline, acting as a separator, would be at the origin of a core annular flow. A core annular flow is characterised by the viscous fluid forming a core in the middle of the pipe surrounded by the annular of the less viscous fluid, in this case the seawater. By assuming a core annular flow in the horizontal section and a mixed flow in the vertical section, this could explain the significantly lower than anticipated pressure drop. Although this type of flow has been observed in the laboratory with viscous oil, it has never been reported in a 6in. pipe. At the end of the test, the pipeline was flushed easily, indicating that the pipe surface was water wet. The combination of evidence, therefore, seems to support this hypothesis.

The project showed the criticality of reliable experimental data when unconventional fluids are expected to be transported through pipeline.

The flow test and the data recorded prove that the heavy oil from the Bentley field can be transported in a controlled manner and based on the information gathered to date, the prediction tools would be able to reproduce the behavior of the fluid within the pipe. **OE**

***Christian Chauvet** is a graduate of the University of Poitiers in France. Chauvet has worked for different industries including the aerospace and automotive industry before moving into the oil and gas industry 10 years ago. He joined Wood Group Kenny (WGK) in 2010 and he is now the North Sea regional manager for flow assurance. In addition, he is the global head of CFD for WGK.*



Global perspective on flow assurance

Flow assurance is set to play a fundamental role in solving major future industry challenges. Martin Brown discusses some of the challenges.

Ensuring successful fluid flow has always been at the heart of the oil and gas industry. However, it is only in the last 20 years that flow assurance has become a classification in its own right. The origins of the term are not known, however, in the early 1990s, the term garantia do escoamento, meaning guarantee of flow, was coined by Petrobras.

Since then, flow assurance has become a key term associated with new and existing developments, and is now generally considered to address all issues critical to ensuring the multiphase transport of fluids, from reservoir to processing host.

The simultaneous transport of oil, gas, and water through pipelines is now standard practice for new developments. Ensuring the successful transit of multiphase fluids over significant distances is crucial to ensuring development profitability. The financial implications of a production interruption, as a result of a loss of flow, can be catastrophic. Flow assurance is, therefore, not only a major technical challenge but a serious economic concern.

Flow assurance techniques include the application of analytical multiphase software, to help understand and evaluate many different types of system. The analytical insight provided can be used to develop technologies which enhance the efficient transport of multiphase flow, making it possible to develop fields which would otherwise be uneconomic.

Flowsure has noticed that global flow assurance efforts are increasingly becoming focused on a number of key development types.

Deepwater

Deepwater currently accounts for about 7% of total conventional production but, year-on-year, the proportion of global discoveries that are classed as deepwater is on the increase.

The key regions for deepwater discoveries are North America (e.g. Gulf of Mexico), Latin America (e.g. Brazil) and Africa (e.g. Angola).

Deepwater flow assurance is focused on managing the low ambient-temperatures and high-pressures on the seafloor. In deepwater remediation costs are very high and any shutdown resulting from a flow assurance incident can be both lengthy and costly.

Managing hydrates during a system shutdown is a crucial operation, which requires complex analysis. Using chemical inhibition is not always the most economical option and complex "preservation" sequences involving partial depressurization and system flushing usually need to be developed. As deepwater risers are significantly longer than conventional risers, the flow instabilities

FPSO, deepwater riser and subsea architecture. Photos from Flowsure .

associated with slugging can be significantly magnified.

Both the slugging characteristics and the conditions under which slugging is initiated must be analyzed and defined so that effective mitigation measures can be developed. The interface of flow assurance with the topside facilities is therefore critical and facilities for handling slugs during normal operation, start-up and system depressurization need to be provided and sized correctly. Where this is not possible, the use of innovative solutions including intelligent chokes need to be considered.

Heavy Oil

Worldwide heavy oil resources (both onshore and offshore) have been estimated as in excess of 7.4MMbbl (2009).

Heavy oil production is well established in onshore and shallow water fields. However, the production costs are higher than more conventional resources, and when situated remotely and in deepwater this effect is heightened.

Heavy oils are characterized by high viscosity and a low API gravity. Heavy oil is typically defined as an oil exhibiting an API gravity < 22°. These factors mean production and transportation of heavy oils can be a major flow assurance challenge.

Heavy oils can be complex and fluid properties difficult to predict using conventional software. Care needs to be

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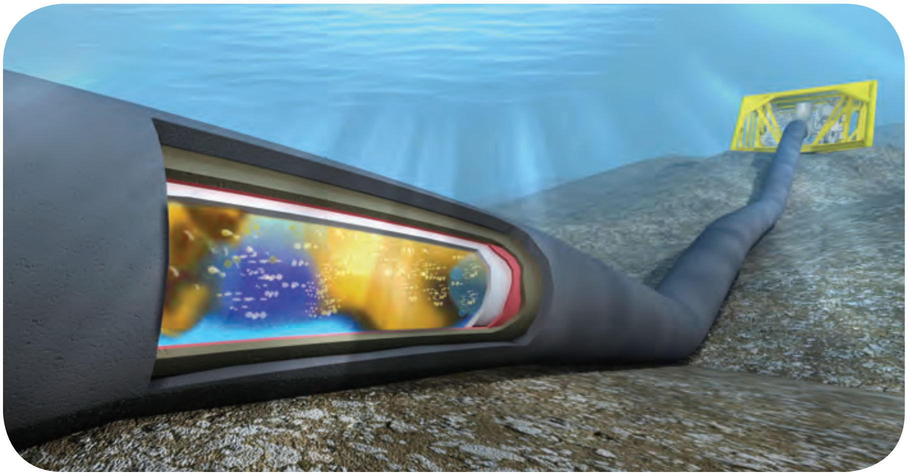
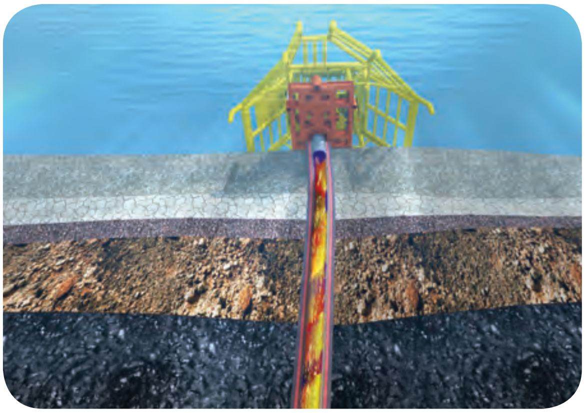


Subsea wellhead and multiphase flow in wellbore.



Multiphase flow in subsea flowline.

taken to ensure simulated fluid properties represent measured laboratory data. Heavy oils are also susceptible to forming emulsions which can significantly increase viscosity.

The effective viscosity management of heavy oils is therefore a key flow assurance issue. The most effective solutions typically involve using heavily insulated/heated pipeline systems and or diluents.

Retaining heat by using high performance passive insulation (OHTC < 1 W/m2K) systems has become common practice in many types of offshore development. In heavy oil systems, heat retention is critical, as small reductions in temperature can greatly increase fluid viscosity resulting in increased pressure drop and reduced hydraulic capacity.

Actively heated pipes are another option for heavy oil systems. These may take the form of pipeline bundles heated through the circulation of hot fluid or electrically heated pipelines. The latter represents relatively new technology, which is becoming more widely utilized.

Using diluents to reduce viscosity (10%-50% by volume) can be expensive, due to the requirement for large umbilicals to transport the chemicals, and needing high chemical storage volumes.

Laminar flow drag reducers have been proven to work on heavy oil fields in the US. These are effectively a form of demulsifying surfactant reportedly reduce the apparent viscosity to around 15-25% of that without the chemical.

At Flowsure our fluids experts have been involved in projects involving water-assisted pipeline transport of heavy oils. Water forms a lubricating layer on the pipe wall while the viscous heavy oil is transported in the inner core of the flow. This approach significantly reduces the energy required to transport these fluids.

Heavy oil deposits are usually low energy and artificial lift with electrical submersible pumps (ESPs) is a proven technology. However, ESP efficiency declines as oil viscosity increases. ESPs therefore work most effectively in conjunction with viscosity lowering techniques. An ESP's impact on fluid shearing and the oil's emulsion forming tendencies must also be taken into account. A hydraulic submersible pump (HSP) driven by hot water may also provide an attractive solution.

Flow assurance also needs to consider the transient behavior of heavy oil systems, in addition to steady state. The issues associated with heavy oils are similar to those of more conventional fluids, but the emphasis on unusual fluid characteristics needs to be addressed. For example, during a long shutdown, a conventional system would be depressurized to prevent hydrate formation. For heavy oils, the resultant lower pressure would tend to lead to an increase in the oil viscosity through gas liberation. An alternative such as hot water or diesel flushing is an option.

Typical hydrate prevention strategies can be detrimental to viscosity management. The start-up of a shutdown system and handling of cold viscous fluids needs to be considered if thermal methods are applied.

High-pressure / high-temperature (HP/HT)

As technology allows the industry to locate and drill deeper discoveries, it has to contend with the associated higher pressures and temperatures. The development of HP/HT fields has become common place in the last five years, as conventional developments have waned and demand has increased. Various definitions for HP/HT fields exist but, typically, these can be classified as shown in Figure 1.

The flow assurance issues associated with HP/HT fields are similar to those of other more conventional fields. However, due to the nature of the reservoirs, these issues tend towards the extreme. Key production chemistry issues include: hydrates, and downhole scale and salt deposition. Continuous wash water may be required at production wellheads to prevent salt deposition downstream of the chokes.

HP/HT fields usually include a dual purpose cooling / warming spool at the wellheads to protect the pipeline design from excursions. The spool allows highly efficient heat transfer and has a cooling duty to minimize temperatures during steady state operation. During start-up, very low temperatures can be generated as the gas cap is blown down, therefore the spool has a warming duty. This helps to minimize cold start durations and optimize chemical injection usage.

Selecting pipeline materials in a HP/HT environment, where using corrosion inhibition becomes less reliable, is also important. Where HIPPS is employed, transient analysis of system behavior is performed to define set points and system design pressures.

HP/HT developments are also increasing in deepwater areas, such as West Africa and the Gulf of Mexico. In these environments, the requirement for bespoke solutions to cope with the extremes in temperature and pressure has to be considered in tandem with limitations on subsea design at the deeper water depths.

Arctic

A US Geographical Survey (USGS) study estimated that the Arctic could hold about 13% of the world's undiscovered oil reserves and as much as 30% of the world's undiscovered natural gas reserves.

Typical Arctic developments include Hibernia (concrete gravity structure), Terra Nova (reinforced FPSO) and White Rose (reinforced turret moored FPSO). Flowlines and wellheads are reinforced to protect against iceberg scour and wellheads are typically located within glory holes on the seabed.

There is a great deal of potential for multiphase developments in the Arctic. However, due to the combination of remote location (long distances to shore), harsh environmental conditions, and a lack of existing infrastructure, it also presents the most complex flow assurance challenges.

The potentially long tie-back distance (>500 km) could be four to five times greater than any existing large diameter multiphase pipelines. This means that existing multiphase flow technology and experience is likely to be tested to its limits.

Rough seabed (due to iceberg scouring) can lead to liquid accumulations and subsequent slugging issues. Sub-zero temperatures represent an issue in terms of hydrate, wax, and ice formation.

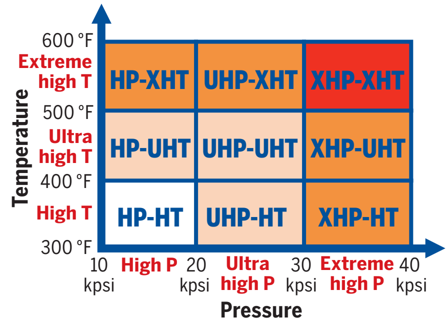


Figure 1: HP/HT definition.

Flow assurance needs to be considered as a life of field solution. All steady state and transient operations should be assessed and a robust system design with proven operability sought. It may be that multidiameter pipelines are used to provide the required operability over a range of flowrates and fluid compositions.

Future Trends

The industry has, over the last decade, seen a huge increase in the development of technically complex offshore fields. Flow assurance, as an engineering discipline, has grown in tandem with this trend. As offshore developments become more technically challenging, understanding key flow assurance issues is paramount to ensuring optimum system design and operability.

To realize the potential of some of the development types outlined above, it is certain that more innovative and bespoke solutions will be required. It is likely that these will involve subsea processing, electrically heated pipelines, and cold flow.

Flow assurance will play a fundamental role in solving major industry challenges and servicing the global market going forward. OE

***Martin Brown** is a Chartered Chemical Engineer (FIChemE) with over 30 years' experience in the upstream oil and gas industry. He is known as a flow assurance technical authority, with specific expertise in HP/HT, deepwater, Arctic developments, and long distance subsea tie-backs. Before establishing Flowsure, Brown worked for a number of major operators and engineering consultancies.*

Taming Tanzania

Statoil, operator of Block 2, has been present in Tanzania since 2007 and calls the country a "key project." Photo from Paul Joynson-Hicks / AP/ Statoil

Tanzania is home to several recent gas discoveries. Yet the country's most recent licensing round doesn't reflect that story. Sarah Parker Musarra discusses why.

With players like Statoil, ExxonMobil, BG Group and Ophir celebrating success in the waters off Tanzania, all eyes were on the country's fourth deepwater licensing round. The affair was delayed multiple times to allow for further seismic; to allow for relinquished areas in existing deepwater blocks to be included; and finally, to allow finalization of the country's natural gas policy.

With a new date, 25 October 2013, picked to coincide with state-run Tanzania Petroleum Development Corp.'s (TPDC) release of the updated model production sharing agreement (PSA), Tanzania offered seven offshore blocks, located in 2000-3000m of water, plus one inland lake permit in the Eastern African Rift System, i.e. North Lake Tanganyika.

A small parade of the world's gas-hungry countries flocked to Dar es Salaam, Tanzania's largest city, for the licensing round, marking China, Russia and the UAE's first forays into Tanzania. Of those offered, the southern blocks, located closest to the resource-rich blocks 1 and 2, received the most attention. China National Offshore Oil Corp. will compete against existing Tanzania Block 2 partners ExxonMobil and Statoil for Block 4/3A. Russia entered the picture through its state-owned company Gazprom, the sole bidder on Block 4/3B. Mubadala Petroleum, of the UAE, bid on Block 4/2A, while UAE-based RAKGAS applied for inland North Lake Tanganyika Block.

The round closed on 15 May, with the bids due 2 June. Four blocks out of eight received little attention. BG Group and Ophir, two of the major Tanzanian players, did not participate in any bids this time. The lukewarm response generated by the bid round has sparked a hotbed of conversation.

A new gas country

Tanzania is widely regarded as the new kid on the natural gas-producing block, compared to long-established producers like the US, Russia, and Qatar.

BG Group entered Tanzania in 2010, and by July 2013 hit nine successful gas discoveries. In June, the count expanded even further with an estimated 1Tcf find in Block 1, which BG Group operates with a 60% interest on behalf of compatriot Ophir. Statoil operates the license on Block 2 on behalf of TPDC with a 65% interest. ExxonMobil Exploration and Production Tanzania Ltd. holds the remaining 35%.

"Tanzania is very new in negotiating for the commercialization of gas. No one can learn these topics quickly," said Etienne Kolly, IHS regional research manager – East Africa. "You cannot compare with more mature countries like Angola." Kolly explained that Tanzania's increase of reserves were "flat" until 2009, when the country claimed reserves of around 1Tcf. In 2011, he said the volume grew to 5Tcf in 2011, culminating in the 31.6Tcf the country is estimated to have today. IHS placed deepwater recoverable reserves at an estimated 29.7Tcf.

Regulations

According to the TPDC, it incorporated in 1969, when the country had one lone concession holder – Italy's Agip (now a subsidiary of Eni).

"The Italian company, then a national oil company, walked away. It did not see the economic potential," said Willy Olsen, INTSOK senior advisor and former advisor to the CEO of Statoil. "Today's major players are less likely to walk away, but they will need terms that are globally competitive to make the final investment decisions."

While the Tanzanian government tried to push legislation through at the speed of exploration, the model PSA might have hindered the licensing round rather than bolstered it.

"It significantly degraded its attractiveness through its new terms," Kolly said, calling the model PSA "too aggressive."

Kolly said that the government made exploration and production financially appealing in 2004, and now, with this

model PSA 2013, fiscally tightened up the terms in an attempt to capitalize on perceived boom money. Harriet Okwi, IHS senior analyst and consultant – Africa oil and gas points to a lack of exploration history, limited available data for Blocks 5A and 5B, and the fact that Blocks 4A and 4B were areas relinquished by BG and Ophir as contributing factors to this "muted" response.

"I believe the terms that came with the licensing round largely contributed to the limited investor interest. The 2013 MPSA reduced the contractor share of profit, raised the royalty rate and lowered the cost recovery ceiling. The MPSA also introduced signature and production bonuses, stricter exploration, and local content requirements and capital gains taxes on transactions."

Offshore royalty rates were raised 2% from the 2008 model PSA to 7.5%. There is a minimum signature bonus payment of US$2.5 million and a production bonus of at least $5 million, payable when production commences. In regards to taxation, any assignment or transfer under the PSA is subject to the relevant taxation law. Tanzania also developed a natural gas policy, and is developing a natural gas bill.

"The natural gas bill will also likely reflect Tanzania's desire to derive more revenue and benefit from its gas resource. This can be done through increased state participation in gas projects, higher taxation rates and more stringent local content policies," Okwi said.

There is another consideration beyond whether the new model PSA is too stringent, Olsen says. Gas takes much longer to monetize than oil, and companies are cutting costs across the board. And, in general, the deeper the water, the deeper the impact on a budget.

"I do not believe the PSA itself frightens off potential firms, but the terms may have become too ambitious, [for example] to the limited response to the last bidding round. Gas is a long term play," Olsen said. "The economics of gas are different from oil and it may keep companies away. It can take years to realize value.

"Tanzania is unlikely to see LNG from the deepwater before 2020-2022. It could be even later…The world has been full of 'stranded gas.' Let's hope East Africa can get its gas to the markets."

Drillship *Discoverer Americas* offshore Tanzania.
Photo from Paul Joynson-Hicks / AP / Statoil

In addition, these factors could inhibit smaller players from participating. Tanzania still requires significant investment in infrastructure, and this is only beginning to be addressed. Statoil and BG Group announced plans in March 2013 to construct a US$10 billion, two-train LNG plant. In its YE 2013 results statement, released March 2014, Ophir said its most recent discoveries, which totaled 15.7Tcf, "will underpin a minimum two 5mtpa LNG train development … and provides encouragement for a potential third LNG train."

June's activity alone might make a case for the third train. On 5 June, BG Group's Taachui-1 STI1 well in Block 1 discovered 1Tcf mean recoverable resources. On 18 June, Statoil struck gas in its Piri 1 wildcat well in Block 2, discovering an additional 2-3Tcf. Statoil now has six discoveries to date ranging up to 20Tcf. IHS estimates Block 2's recoverable reserves at 13.6Tcf.

A spokesperson for Statoil said that the potential LNG development would be onshore, and that all companies in blocks 1 through 4 – meaning Statoil, ExxonMobil, BG Group, Ophir Energy, and Pavilion Energy – submitted a joint proposal to the Tanzanian government.

"The five international oil companies have been working closely with TPDC and the Ministry of Energy and Minerals on various steps and processes that are needed before the site is announced," Statoil's spokesperson said.

The government, with its eyes set on exports, is striving to work with operators and place infrastructure as quickly as possible – a tough proposition when the country has its own energy needs to worry about. The 180MMcf/d produced by Tanzania's two existing fields, Mnazi Bay and Songo Songo, go to the country's own domestic needs, which Kolly calls a "huge deficiency in power generation and power access." The World Bank states that only 15% of the local population has access to electricity.

Like most countries with newly-discovered resources, Tanzania is rushing to get its regulations and infrastructure up to speed with the pace of new discoveries. Kolly acknowledged that Tanzania was years away from exporting but remained optimistic.

"Activity is really booming and they (the government) are working hard," he said. "They want to do well, not reproducing errors done in the past by more mature countries like Nigeria – especially, they want to maximize returns for local people and push for local content," he said. OE

BG Group used Odfjell's Deepsea Metro I drillship for the Sunbird-1 in Block L10A this year. Photo from BG Group.

Kenyan explorers look deeper offshore

By Nina Rach

Offshore East Africa is among the newest frontier exploration regions, with results of wildcats eagerly awaited. The area still lacks infrastructure to support meaningful development and logistics remain a challenge to all comers. The activity has spread beyond the shores of Kenya, Tanzania, Mozambique, reaching Madagascar, the Comoros, and the Seychelles.

All of Kenya's offshore blocks are in the Lamu basin, which formed during the separation of Madagascar from Africa and has Middle to Late Jurassic source rocks. The exploration focused in the Lamu basin follows a successful trend from Mozambique and Tanzania. Small independent operators are surrounded by majors, leading to interesting industry partnerships and strategic opportunities for companies large and small.

Years of activity

In 1964, BP and Shell drilled the onshore Dodori-1 well to 4311m TD very close to the coast. The well reached Campanian rocks in the late Cretaceous section, with oil and gas shows in Tertiary and Cretaceous. This well flowed at 3.1mcf/d.

In 1971, BP and Shell drilled the Pate-1 well south of the Dodori well, in the L5 area, to 4188m TD, reaching Eocene sediments with gas shows. It flowed at 12.7mcf/d.

In the same year, they drilled the Kipini well to the south, close to the coast in the nearby L-6 area, to 3663m TD. It reached the Campanian section, with fluorescence and gas shows in Tertiary and Cretaceous section.

In 1978, France's Total drilled the offshore Simba-1 well to 3604m TD, with wet gas shows (C_1-C_5) in the Tertiary.

In 1982, a consortium of Cities Services, Marathon and Union drilled the offshore Maridadi-1 well to 4198m TD with gas shows in the Tertiary, and in 1985, drilled the offshore Kofia-1 well to 3629m TD, with oil and gas shows.

Out-going KPA Chairman Shukri Baramadi (at right) congratulates incoming Chairman Danson Mungatana (at left). Photo from Kenya Ports Authority.

A Lamu basin study 1991-1995 led Kenya to subdivide the Lamu embayment (both onshore and offshore) into 10 exploration blocks and then add two more after 2001.

Between 2000-2002, seven production sharing agreements were signed for offshore Lamu basin blocks L5, L6, L7, L8, L9, L10, and L11. In 2003, Australia's Woodside Petroleum acquired 7884 km of 2D seismic data covering the seven licensed blocks as well as Block L12. Woodside then drilled the deepest offshore well in 2006.

Anadarko acquired 5000 line-km of 2D seismic data over offshore blocks L5, L7, L12, L11A and L11B, followed by 3D seismic.

By December 2009, Origin Energy acquired 900sq km of 3D seismic over Block L8, using M/V *Seisquest* to tow eight streamers, 5100m long.

Afren, through its subsidiary EAX, acquired 460km of shallow-water and transition-zone 2D seismic over Blocks L17 and L18, completed in October 2010.

In 2011-2012, Ophir Energy acquired Dominion Petroleum for £118m (US$186million).

In November 2011, BG began acquiring 3D seismic data in license areas L10A and L10B, followed by a 2D seismic survey over the western area of the blocks (the Sunbird area).

In January 2012, Afren (EAX) completed acquisition of 1207km of 2D data in the deeper water portions of Blocks L17 and L18. In December 2012, it completed acquisition of 1006sq km of 3D data (in lieu of a well commitment), and the 3D was processed by July 2013.

In June 2012, Total signed a PSC for 100% of offshore license Block L22, with water depths of 2000m to 3500m. The first phase of exploration is 3D seismic acquisition.

In July 2012, PTT E&P Thailand agreed to a $1.93billion acquisition of Cove Energy, which had interests in several blocks offshore Kenya.

In 2012, Fugro-Geoteam AS completed the Kifaru 3D seismic survey including 778sq km over Block L6 for FAR Ltd. and Pancontinental. Fugro's *Geo Caribbean* seismic vessel stopped in Cape Town in May 2012.

Discoveries

Working oil and gas systems were only recently proven offshore Kenya, beginning with the Mbawa-1 well on the western side of Block L8. The well reached 2553m in September 2012 and encountered 51.8m net gas pay in porous Cretaceous sandstones. It was then drilled further to 3275m TD. Apache Corp. operates the license (50%) on behalf of partners Origin Energy (20%), Pancontinental (15%), and Tullow (15%). Apache's Exploration Director Angus McCoss said at the time: "A gas discovery on prognosis in the shallowest objective at Mbawa-1 is an encouraging start to our East African transform margin exploration campaign." However, the find was not commercial, although Apache said it would keep the option to re-enter the well open.

In April 2013, Anadarko announced that its Kubwa well in Block L7 was not commercial.
The company's Senior Vice President for worldwide exploration Bob Daniels said, "The Kubwa well tested multiple play concepts and provided useful data regarding the prospectivity of our six-million-acre position offshore Kenya."

In October 2013, Apache relinquished its 50% stake in the L8 block, saying that gas volumes were not commercially viable.

Likewise, in December 2013, Britain's Premier Oil announced that it was withdrawing from Block L10A and relinquishing its 20% stake in the license. However, Premier retained its 25% share in neighboring Block L10B.

Pancontinental announced a small gas discovery in Block L8 in December. Pancontinental's finance director Ernest Myers said, "The well on its own may not currently be commercially viable, but could be when aggregated with other gas discoveries which may occur in the L8 or nearby blocks."

On 6 January 2014, Pancontinental and BG spud the Sunbird-1 well with the *Deepsea Metro-I* drillship in 723m water depth, Block L10A, and drilled to 2850m, penetrating the top of the Sunbird Miocene reef at 1583.7m subsea. It became Kenya's first offshore oil discovery, confirmed in June 2014.

Kenya offshore interests

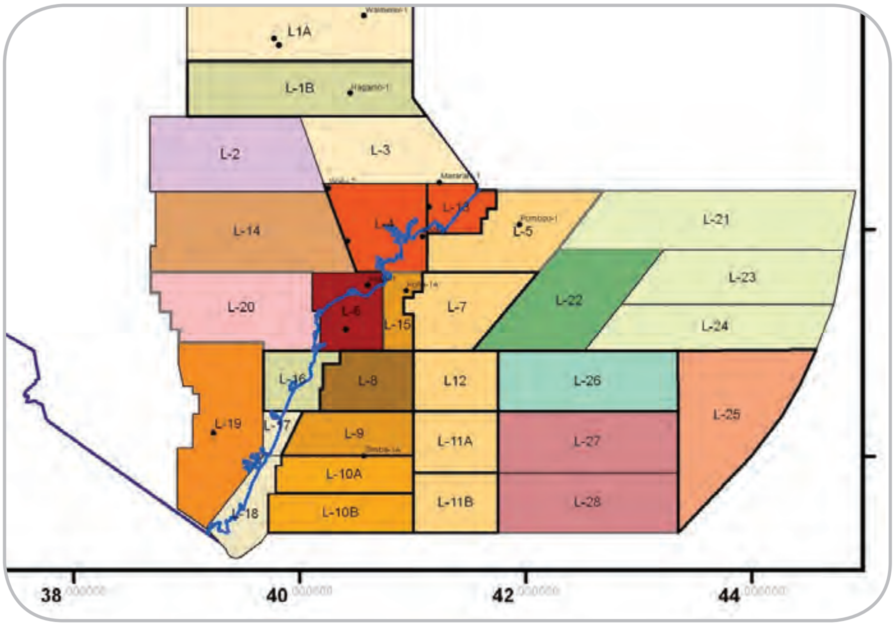
Blocks with planned drilling are shaded

Offshore Block	Acreage	Ownership	Status
L4	7510sq km	Zarara Oil & Gas Ltd. 75%, SOHI Gas 25%	Predominantly onshore block
L5	8735sq km	Anadarko 50% Total 40%, PTTEP 10%	Territory partially claimed by Somalia
L6	5010sq km (3134sq km offshore)	FAR Ltd. 60% Pancontinental 40% (offshore shares)	Undrilled, shallow water coastal block. Ophir farmout to Milio International.
L7	6944sq km	Anadarko 50% Total 40%, PTTEP 10%	Kubwa well, May 2013 – oil shows
L8	5123sq km	Apache 50% Origin Energy 20% Pancontinental 15% Tullow Oil 15%	Mbawa-1 gas discovery, Sept. 2012
L9	5100sq km	Ophir Energy 90% FAR Ltd. 10% (will increase to 30% subject to gov't approval)	Simba-1 well drilled 1978. Will drill a DW well in H1 2015. WD to 1400m.
L10A	4962sq km	BG Group 50% PTTEP 31.25% Pancontinental 18.75%	Sunbird-1 oil, gas discovery, March 2014, 723m WD.
L10B	5585sq km	BG Group 45% Pancontinental 20% PTTEP 15%	
L11A	5009sq km	Anadarko 50% Total 40%, PTTEP 10%	
L11B	4963sq km	Anadarko 50% Total 40%, PTTEP 10%	Kiboko well P&A Sept. 2013
L12		Anadarko 50% Total 40%, PTTEP 10%	
L13	3000sq km	Zarara Oil & Gas Ltd. 75%, SOHI Gas 25%	Territory claimed by Somalia
L15	2331sq km		Kofia-1 well drilled in 1985. Relinquished by Ophir Energy in 2013.
L16	5027sq km	Camac Energy Gov't Kenya	
L17	1259sq km	Afren/EAX	
L18	3583sq km	Afren/EAX	
L21		ENI	Territory claimed by Somalia
L22	10,000+sq km	Total	Territory claimed by Somalia
L23		ENI	Territory claimed by Somalia
L24		ENI	Territory claimed by Somalia
L25			Territory claimed by Somalia
L26		OPEN (Edgo Energy, Qatar First Investment Bank)	Territory claimed by Somalia
L27		CAMAC Energy Gov't Kenya	
L28		CAMAC Energy Gov't Kenya	

What's ahead

Several major international oil companies—BG Group, Tullow, Total, ENI, and Anadarko— have aggressively pursued prospects off Kenya, and operators appear more willing to drill commercial-sized oil prospects now that source rocks and oil-generation timing has been proven.

Will Anadarko drill again off Kenya? Perth-based Pancontinental Oil & Gas NL said in a June 2014 presentation that it would potentially re-enter Kenya offshore Block L8 in the second half of this year. The Kenyan government also granted the company a 12-month extension for the



Kenya's coastal and offshore exploration blocks

initial exploration period of the L10B license area.

Ophir Energy, which holds a 90% interest in Block L9, had said it would drill a well in 3Q 2014, but in a June 2014 investor presentation, announced that it was pushed to 1H 2015. This may be related to the farm-out to FAR of 30%, subject to government approval. The prospect has P50 reserves of 190MMboe gross and 171 MMboe net.

FAR anticipates drilling a well in Block L6 at the end of 1Q 2015.

Afrin (EAX) is preparing to drill two wells in 2015 in Blocks L17/L18.

Ultra-deepwater Block L26 is not currently under license. Edgo Energy, the exploration unit of Jordan's Edgo, and joint venture partner Qatar First Bank relinquished the block in January 2013. Mazen Masri, managing director of Edgo, cited the technical and monetary challenges of drilling in water depths beyond 1500m, and also mentioned that the block is subject to a maritime border dispute, claimed by both Kenya and Somalia.

NOCK

The National Oil Corp. of Kenya Ltd. (NOCK) is a state-owned company that was established in April 1981 to spearhead exploration.

A new Petroleum (Exploration & Production) Act was enacted in 1984, and revised in 1986, when royalties were replaced with production sharing contracts. Through 2012, most of Kenya's PSCs gave NOCK a 10% stake in production, raised to 25% in 2013, along with higher fees and new capital gains tax rules.

Kenya's first competitive licensing round has been postponed to at least 4Q 2014, and GlobalData's sub-Saharan upstream analyst John Sisa said in May that the delay could benefit the country if additional discoveries are made in the interim.

Logistics

Adequate ports and docking facilities are still in short supply along the East African coast. The different types of vessels needed to support a robust exploration program require supply and repair yards and berthing options.

The Kenya Ports Authority manages the Port of Mombasa, named Africa's fifth largest for container shipping in 2013, based on increased traffic after capacity expansion. In January, incoming KPA Chairman Danson Mungatana expressed his support for the development of small ports program and said the new commissioning of the standard gauge railway line would "revamp the transport sector and…support port efficiency."

Kenya is boosting existing port facilities with the construction of a $3.5billion Lamu port.

The Kenya Maritime Authority (KMA) was set up in June 2004 to provide regulatory oversight of the Kenyan marine industry. KMA implements international maritime conventions and promotes safety, security, maritime training, search and rescue, pollution prevention and the preservation of the marine environment. KMA's mandate, as stipulated in Kenya's KMA Act 2006, is "to regulate, co-ordinate and oversee maritime affairs."

Roads connecting ports, airports, and other supply routes need to be bolstered to support the heavy loads, as well as move personnel.

The oil and gas industry along with emerging sectors of the economy and a growing middle class have boosted civil aviation needs in the region. The country's main airport is Jomo Kenyatta International (Nairobi), and there are smaller airports at Wilson, Mombasa, Eldoret, and Kisumu.

Bobby Bryan, Delta Airlines commercial manager for East Africa and West Africa, told the Discover Global Markets Conference in May that airports, aircraft, adequate fuel supplies and staff are necessary to service vessels and crews. Delta has an office in Nairobi and opened one in Dar es Salaam a year ago. It partners with KLM and Kenya Airways.

In a January 2013 report, Deloitte & Touche described Kenya's economy as "energy starved" and that may hamper rapid infrastructure development.

Security

Securing infrastructure, operations and personnel safety is a primary consideration. Given Kenya's proximity to Somalia and shared, but porous, maritime border, critical infrastructure – electric, gas, telecoms, transportation, water and food supplies – supporting the offshore industry may be a constant target.

Increasingly frequent terrorist attacks, some of which the Kenya National Disaster Operation Centre attributes to Somali militant groups, may negatively influence investment investments and possibly forestall exploration activity in Kenya.

Earlier this year, bomb and grenade attacks in Nairobi and the coastal city of Mombasa led the UK, US, France and Australia to issue travel warnings. As this issue goes to press, Somali militants attacked hotels and killed dozens in Mpeketoni, a coastal town in Kenya's Lamu County, another blow towards destabilizing the tourist economy.

With evolving threats, Kenyan government efforts to protect people and critical infrastructure must evolve as well, or the country risks losing petroleum investment.

The East Africa Oil & Gas Summit (EAOGS) will take place in Nairobi this October, and we'll see what a few months more will bring. OE

Mozambique: resource curse or opportunity?

Mozambique is thought to be the jewel in East Africa's crown, but will its abundant gas resources pay off for the country? Audrey Leon reports.

Mozambique, with all its natural beauty and massive resources, has been a hot topic in the industry for some time. While the country is recognized for being one of the fastest-growing economies, with 7.6% growth in GDP in 2013, it still has plenty of challenges.

Ana Maria Raquel Alberto, commercial counselor for the Embassy of Mozambique, told attendees at this year's Offshore Technology Conference (OTC) in Houston, that despite challenges that include poverty, qualified workers, training, and infrastructure, the country desires to be an attractive partner with industry. "We want Mozambicans to be employed by your companies," she says.

While Mozambique is energy resource rich, only 12% of Mozambique's population has access to electricity, according to World Bank data. Power transmission and remoteness are two key challenges that Mozambique needs to address, according to IHS' Chief Upstream Strategist Bob Fryklund, who also spoke at OTC. "Mozambique has a way to go; that's why we see FLNG as a production option. The remoteness is a challenge."

Resource curse

In his presentation, Fryklund discussed the possibility of Mozambique falling victim to the resource curse. "Mozambique is in a race to figure out what to do with its resources, asking should it be available for domestic use or export," he says.

Fryklund estimated that Mozambique contains oil resources of 2.5MMbbl, and natural gas resources of 200Tcf and growing, calling the country's resources a "world-class amount of gas." However, Fryklund feels it is a race to monetize those rich resources. "That's where the curse comes in," he said. "People are trying to get in there first."

Fryklund continued, telling the OTC audience that with 30 million tons of LNG at stake, East African LNG needs to be priced competitively. When compared to Qatar, the Middle Eastern country's gas is still the cheapest.

"You have the US, Canada, West Africa all coming up. There's such a thing as 'mega-project disease,' Fryklund says. "We're competing against ourselves. We're trying to do so much at the same time: Using the same people, technology, EPC contractors."

Resource paradox

However, Fryklund believes governments that find a way to balance maximizing their investments and taking care of their local workforces will do well, and cites Norway as an example. Currently, several East African governments, including Mozambique and Tanzania, are revising regulations and production agreements. "Many governments in East Africa are going through debate on whether they should increase fiscal take now or choose a more balanced approach," Fryklund says. Local content is a huge topic in several countries including Brazil, Ghana, Nigeria, and Angola. Fryklund cites Nigeria and Ghana in particular for setting high local content requirements 45% and 50%, respectively.

"Many countries are reconsidering local content. Nigeria set a record with Egina – 45%, but it needs to be competitive and sustainable," he urges. "When these projects finish and work is done, you're unemployed. Not a problem if you have more projects lined up – this is where competitiveness comes in."

The future

In May, Italy's ENI touted Mozambique's latest find: a 25m gas column in good-quality Paleocene reservoir sandstones was discovered by the Agulha 2 well in Area 4, which ENI operates through ENI East Africa (70%). The find also confirmed the southern extension of the field. Total resources discovered in Area 4 are estimated at 85Tcf.

Houston-based Anadarko and ENI have teamed up to develop a two-train onshore LNG facility at Afungi in Palma, located in the Cabo Delgado province, by 2018. The partners eventually aim to have a capacity for 50MTPA of LNG.

Fryklund says what Anadarko and ENI are doing is the right idea because while they own their own trains and resources, uniting to build an onshore LNG facility will cut down on costs. He noted a similar project, Atlantic LNG in Trinidad and Tobago, serves as a model for this type of project. Current owners BP, BG Group, Shell and Trinidad and Tobago LNG hold stake in the four-train Atlantic LNG facility, which has a total production capacity of 15MPTA.

In April, ENI announced a pre-FEED for two 2.5MTPA floating LNG facilities to produce from its Mamba gas field. An investment decision is expected next year. ENI said investments in Mozambique could tally up to US$50 billion. OE

IHS' Chief Upstream Strategist Bob Fryklund addresses the 2014 Offshore Technology Conference. Photo: Audrey Leon/OE.

Tank support for the LNG revolution

A modern descendant of the first LNG containment system for ships could become one of the key technologies carrying gas transport and trading into tomorrow. Joe Evangelista reviews its evolution.

When the new Panama Canal opens in late 2015, it will give easy cross-ocean access to much of the current world LNG carrier fleet. Such ease of transport could help the current regional pricing of natural gas and give rise to a consistent worldwide market in which gas is traded like oil. If that happens, a regular spot market for LNG could develop, presenting new opportunity as LNG traders would need carriers that can travel with partially loaded tanks.

Based on the design of traditional bulk liquid cargo spaces, the IHI-SPB is a prefabricated metal tank designed for transporting liquefied gases. It has a particular combination of characteristics that is drawing intense interest from the energy sector among operators considering building floating LNG facilities and from the shipping sector among owners contemplating the emergence of an LNG spot market.

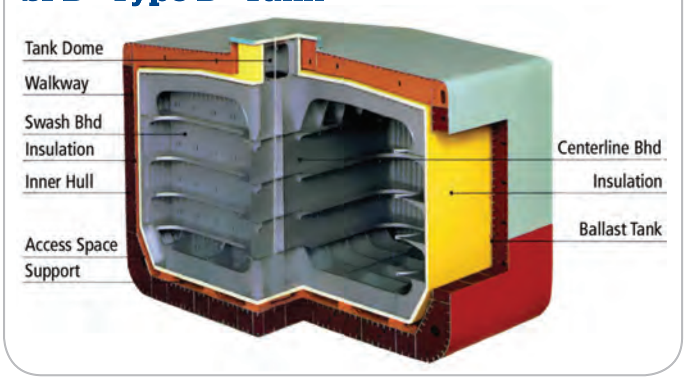
Tank support for gas-fueled initiatives

Developed in Japan by Ishikawajima-Harima Heavy Industries (IHI), the next-generation LNG containment system has spent a long time waiting for its day in the sun. It received approval in principal (AIP) from ABS in 1983, made its first appearance in an LNG carrier in 1993 and now is poised to help the natural gas industry grow, evolve and meet the needs of a changing world.

Although the IHI Group merged its shipbuilding division with Universal Shipbuilding to form Japan Marine United (JMU) in early 2013, the containment system retains its original name: the IHI-SPB tank. SPB stands for self-supporting, prismatic IMO Type B independent tank containment system. The word "independent" means the cargo hold is not integral to the ship's hull. "Prismatic" refers to the tank's beveled geometry. And "Type B" denotes its classification under the *IMO Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk*, more commonly known as the International Gas Code (IGC).

The principal attractions of the tank are a proven immunity to sloshing problems that allows LNG ships to go to sea partially loaded – even in harsh weather – and a customizable geometry that, among other benefits,

SPB "Type B" Tank



The SPB "Type B" tank was developed in Japan by IHI and received AIP from ABS in 1983. Photo from ABS *Surveyor*.

ABS-classed *Sanha*, the world's first LPG FPSO.

results in the kind of flat-deck vessels needed for floating processing plants

While JMU was not the pioneer of this technology, the company applied sophisticated computer analysis capability to redevelop and improve on the original concept to make it work as a Type B tank and incorporated it in the *Sanha*, the world's first FPSO for LPG.

A history of LNG containment

The first maritime LNG containment system was a prismatic tank of the Type A variety, installed in a World War II-era cargo ship converted for gas carriage under ABS class in 1958. Renamed *Methane Pioneer,* the ship carried LNG from Lake Charles, Louisiana, to the Canvey Island terminal in England. The success of that conversion – the vessel remained in service for a decade and finished up doing LPG storage – may have significant repercussions in light of today's changing gas markets.

Another ancestor of the SPB tank made LNG transport a global business in 1964,when the first purpose-built LNG carriers, ABS-classed *Methane Progress* and *Methane Princess,* entered service. These vessels used an update of the prismatic Type A concept developed by the Conch Co. The inner hull was lined with insulation, and the tanks rested on wooden support blocks.

IHI began building prismatic Type A tanks for LPG, ammonia and ethylene carriage in 1960. After making a name in those sectors, the company focused its engineering efforts in 1980 on the challenge of evolving the Conch concept into a freestanding or self-supporting Type B tank. Rigorous studies were made to substantiate the design, including ship motion analysis, FEM (finite element method) analysis of the tank and hull, fine-mesh FEM analysis of local structures, fatigue analysis and crack propagation analysis. Even the insulation system, which is not load-bearing, was subjected to extensive model tests. The tests further demonstrated the suitability of the system to withstand dynamic loads caused by ship motion and thermal cycling and proved its liquid leakage protection for a continuous 15-day period.

Raising the future through the past

SPB technology first entered service in 1993 aboard *Polar Eagle* and *Arctic Sun*, a pair of ABS-classed vessels built at the IHI shipyard in Aichi. Although only two vessels were built with the SPB system, their record during 20 years of nonstop service on one of the world's most severe and challenging runs thoroughly proved the strength and durability of the tank design. The shipbuilder now sees an opportunity for its containment technology to take an important place in emerging LNG markets and applications.

This design eliminates the sloshing problem and has proven capable of handling partial loading under extreme sea conditions. This makes it a viable candidate for floating terminals, where tanks are constantly in a state of partial filling.

Internally, the tank is modeled on conventional bulk liquid cargo holds – a stiffened plate structure subdivided into four spaces by a centerline liquid-tight bulkhead and swash bulkheads. As in a traditional bulk liquids carrier, the bulkheads control the natural frequency of the cargo. By preventing ship motions from creating resonance with the liquid, they eliminate sloshing problems, and the capability for partial loading allows a ship to quickly leave the berth in the event of an emergency.

LNG projects on the rise

By Stephen Gordon, Clarkson Research

Rapid development in the LNG sector underscores the significant role technology will continue to play in the natural gas industry and energy markets. LNG shipping has grown significantly over the last 20 years, accounting for 32% of all natural gas trade in 2012 – up from 24% in 1990. Between 1990 and 2012, LNG trade increased by a compound annual growth rate of 7.2% compared to 5.4% per annum for pipeline gas and 2.4% for global gas demand over the same period. Global LNG trade increased from 52 million metric tons (mmt) in 1990 to 222mmt in 2010. By 2013, trade volumes had increased to an estimated 244mmt.

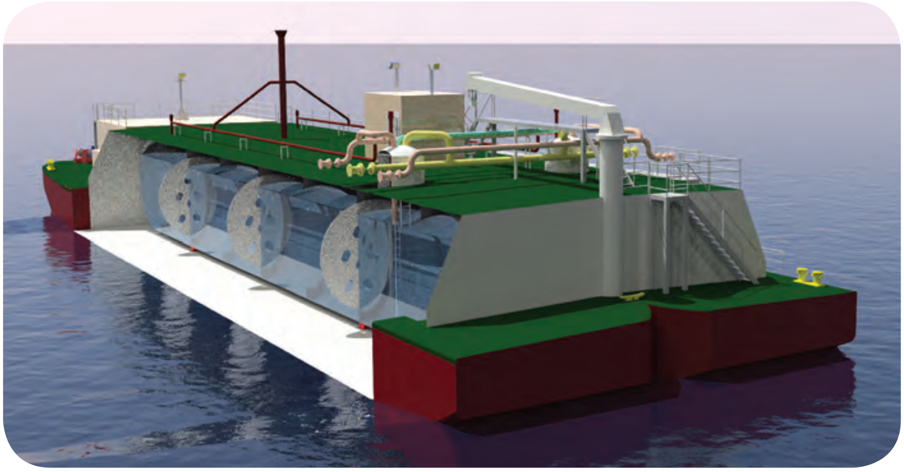
At the end of 2004, only 10 countries were exporting LNG. At the beginning of April 2014, there were 17 countries (with 89 liquefaction trains) that have LNG liquefaction infrastructure. The total production capability of these units is estimated at 293mmt per annum. Qatar remains the largest exporter, with volumes reaching 78mmt in 2013, equivalent to one-third of global exports.

The import side of the LNG business comprised 107 facilities at locations in 30 countries at the beginning of April 2014. And growth in this sector is expected to continue. There are 16 LNG liquefaction plants under construction, with a further 27 projects that have received FID or are at the FEED stage. These developments, along with other potential projects, are expected to support firm trade growth over the long term, despite short-term delays to project startups. It is worth noting that there is significant potential for export growth in the US and Australia.

Global numbers for 2013 indicate Asian nations accounted for three-quarters of global LNG imports, with Japan, South Korea, India, China and Taiwan ranking as the top five LNG import destinations. LNG trade routes between countries have multiplied as well, increasing from 45 in 2003 and 93 in 2008 to 168 in 2013.

Changes in the global LNG carrier fleet also reflect an expansion. In 1996, the fleet stood at 90 ships, nearly doubling to 174 by the start of 2005 and rising to 361 by the start of 2011. Today, the fleet stands at 392 vessels.

With the global demand for gas escalating, the LNG industry is poised for continued growth. ■



JMU says the shape flexibility of the IHI-SPB makes it an ideal alternative to the Type C tank, shown here in concept renderings for TOTE's gas-fueled containerships and Waller Marine's articulated tug barges. Images courtesy of TOTE and Waller Marine

New future, new ideas

The performance of the two existing SPB-equipped LNG carriers indicates this technology could help the LNG sector evolve and advance into new markets and services.

The main factor that has kept SPB technology out of the LNG building boom of the last decade was not performance, but price. Until 2012, an SPB containment system for an LNG carrier cost about 15% more than a comparable membrane system. Today, according to the manufacturer, the SPB premium is less than 10% more than a membrane system. As orders increase, there is an expectation that production efficiencies will further lower costs. This could well be aided eventually by efficient licensees building tanks in other countries.

Most enquiries for SPB systems to date have come from energy companies considering floating production, storage and terminal facilities for offshore developments, but recently, with Japan looking to increase LNG imports over the coming decade, interest in the system among domestic shipowners has begun to rise.

As SPB tanks are, by nature, custom-built for each ship, they can be tailored to fit any hullform. This raises the possibility of converting existing ships for LNG service, presenting a potential boon to emerging markets needing shuttle tankers and shipowners looking to change the direction of a half-built vessel. While all this may not mean the coming of a future world fleet containing combination carriers with liquefied gas capacity, or parcel tankers hauling LNG as just another hazardous cargo, it does seem to signal interesting times ahead. OE

EDITOR'S NOTE: *A version of this article appeared in the Fall/Winter 2013 issue of Surveyor, a quarterly magazine from ABS.*

Differentiating among tank types

The IGC Code defines membrane tanks as well as three type categories for independent LNG cargo tanks.

Membrane tanks are non-self-supporting tanks which consist of a thin layer (membrane) supported through insulation by the adjacent hull structure. The membrane is designed in such a way that thermal and other expansion or contraction is compensated for without undue stressing of the membrane. This containment system requires a complete secondary barrier capable of containing the cargo for a 15-day period, and typically the membrane tanks do not exceed a 0.25 bar design vapor pressure; however if the hull scantlings are increased accordingly the design vapor pressure may be increased to 0.7 bar. Today, Gaztransport & Technigaz (GTT's) systems, which are approved by all major classification societies, have a capacity range for existing vessels of 20.000-266.000cu. m. The tanks are also being considered for smaller-sized LNG carriers and LNG barges, as well as fuel tanks on gas-powered vessels.

Type A tanks are designed primarily using recognized standards of classical ship structural analysis and constructed of a plane surface. The code limits this type of tank to a vapor pressure of less than 0.7 bar, and where minimum design temperature is below -10°C, requires a complete secondary barrier capable of containing the cargo for a period of 15 days in the event of a ruptured or leaking tank.

IMO Type B independent tanks are defined as "designed using model tests, refined analytical tools and analysis methods to determine stress levels, fatigue life and crack propagation characteristics." One of the key characteristics for Type B designation is compliance with the "leak before failure" concept, under which crack propagation analysis by fracture mechanics techniques must demonstrate that if a crack in the system should develop, its growth will not be rapid enough to allow excessive leakage into the cargo hold. A partial secondary barrier, which can consist of a spray shield and drip pans, is required for independent Type B tanks with minimum design temperatures below -10°C. Prior to the IHI-SPB, all Type B tanks were spherical vessels of the Moss-Rosenberg design.

Type C tanks are spherical or cylindrical pressure vessels, like those typically seen topsides on LPG carriers. Because these tanks can be made to fit into any available space in the ship, the Type C tank is ideal for the fuel tanks in gas-powered vessels. ABS granted AIP for this application in 2011 when JMU developed a concept design for a gas-fueled containership. This is the type indicated for the fuel tanks being fabricated as part of the design for TOTE's gas-fueled containerships and Waller Marine's articulated tug-barges for local LNG distribution and supply. ■

Floating LNG facilities:

are they 'vessels' for purposes of liability limitations?

Vinson & Elkins' David Lang and Paul Greening discuss determining whether and FLNG facility can receive limitations of liability for maritime claims.

The oil and gas industry relies on a wide range of maritime infrastructure to undertake its offshore exploration and production activities. Shell and Texaco pioneered offshore drilling with the first barge-mounted drilling rig in 1947. Offshore production of oil and gas relied on infrastructure predominately fixed to the seabed until Shell deployed the first FPSO (the *Castellion*) in 1977. Today, more than 200 vessels are deployed worldwide as FPSOs. Offshore technology (as well as gas liquefaction technology) has evolved so that there are numerous floating LNG regasification facilities in operation and a number of floating LNG production facilities under development and construction.

As various concepts for floating facilities for production and regasification of LNG (FLNG) take shape, it is useful to evaluate certain maritime principles and their applicability to FLNG facilities. In particular, it is useful to consider whether liability limitations traditionally afforded to trading vessels will apply to FLNG facilities.

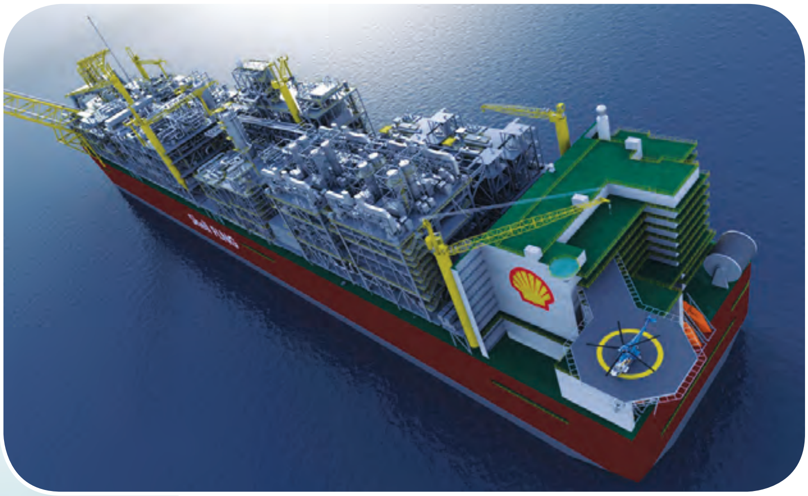
The question of whether FLNG facilities will be treated in a similar way to commercial trading ships, such as tankers, or whether they will be regulated as if they were permanent offshore installations, such as well head platforms, is a critical question from a legal and regulatory perspective. It determines not only which laws and regulations will apply to the operation of such facilities, but, crucially, whether their owners will be afforded limited liability with respect to third parties in the event of a serious incident.

Various international regimes generally allow the owners and charterers of traditional "vessels" or "ships" to limit their liability in the event of loss or injury to persons or things caused by or on board a ship. The key regimes include the following:

- **Limitation of Liability Convention 1957 and 1976 (as amended by the 1996 Protocol; 1957 LLMC and 1976 LLMC, respectively):** entitles a "shipowner" (which includes a charterer, manager or operator) to limit its liability with respect to death, personal injury and property damage occurring on board or in direct connection with the operation of a ship to an amount calculated by reference to the ship's gross tonnage.
- **International Convention on Civil Liability for Bunker Oil Pollution Damage (Bunker Convention):** limits an owner's liability for pollution and environmental damage caused outside the ship by contamination resulting from the escape or discharge of bunker oil from the ship.
- **International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances at Sea (HNS Convention):** if ratified, will provide for a liability and compensation regime for environmental damage caused by spillages of hazardous and noxious substances (including LNG) by ships at sea.
- **Federal Limitation of Shipowners' Liability Act in 1851 (US Limitation Act):** Like the 1957 LLMC and 1976 LLMC (neither of which have been adopted by the United States), limits shipowner liability for damages to third parties arising out of the ship's operation.

Applicability of shipowner liability limitation regimes to FLNG facilities

Given the potentially enormous risk exposure that is now a reality of operating offshore, one might assume that it would be clearly established whether or not the owners, charterers and operators of any FLNG facility are entitled to limit their liability under conventions such as the 1957 LLMC, 1976 LLMC, the US Limitation Act, Bunker Convention and HNS Convention (once ratified). In reality, the scope of coverage of such conventions is a somewhat grey area. In order



Rendering of Shell's *Prelude* FLNG. Photo from Shell.

to benefit from the liability limits set by such conventions, the specific facility in question would need to fall within the scope of the definition of a "ship" (in the context of the LLMCs) or a "seagoing vessel" or "seaborne craft" (in the context of the Bunker Convention and HNS Convention (once ratified)) or a "vessel" (in the context of the US Limitation Act).

What constitutes a "ship" or a "vessel"?

The provisions of the LLMCs clearly indicate that the convention is intended to apply to all "ships" other than "drilling ships or floating offshore platforms connected to the seabed."

To determine the applicability of the LLMCs to an FLNG facility, we must therefore determine that the facility is a "ship" and that it is neither a "drilling ship" nor a "floating offshore platform connected to the seabed." While there may be some interesting questions as to whether a particular FLNG facility might fall into the latter category, this article will focus on the question of what makes a facility a "ship" for purposes of the LLMCs. Unfortunately the word "ship" is not defined in the LLMCs, so we need to look to other conventions, sources of legislation and case law for guidance.

In the UK, the LLMC has been implemented domestically by the Merchant Shipping Act 1995, which defines a "ship" to include "every description of a vessel used in navigation." The inclusion of a vessel "used in navigation" is an important practical refinement of the definition of what constitutes a "ship" but there is still significant room for interpretation of what it means to be a "vessel" and "used in navigation."

Looking to recent case law in both the UK and the US provides a useful indication of how a court would go about defining the key characteristics of a floating facility that must be present (or not present) in order for such floating facility to be regarded as a "ship" or a "vessel" for the purposes of attracting limited liability under the various international regimes.

A review of the relevant case law in the UK and the US suggests that it will be the satisfaction or non-satisfaction of certain criteria that will be critical in determining whether a particular FLNG facility can be regarded as a "ship" for the purposes of attracting limited liability under the various regimes.

United Kingdom

1. Use of the ship in navigation

2. In 2005, in R v. Goodwin, the English Court of Appeal considered the practical meaning of the phrase "used in navigation" and concluded that a "ship" for the purposes of the Merchant Shipping Act will not include craft that are simply used for having fun on the water without the object of going anywhere (in this case, a jet ski), reasoning that the words "used in navigation" require some kind of "ordered progression from one place to another." In the UK context, it would therefore appear that if the FLNG facility in question is capable of "ordered progression" from "one place to another" (e.g. relocation from one site to another), it may qualify as a "ship" under the Merchant Shipping Act and, as a result, the owners, manager, charterers and operators of such FLNG facility would be afforded the benefit of the limitation of liability regime. Although the issue has never been tested before the courts, the question of how frequently a particular FLNG facility relocates (and by what method) could well be a secondary consideration of the court in determining whether such facility should be regarded as a "ship."

3. Purpose of the ship

4. In 1945, the English Court of Appeal was asked, in Polpen Shipping Company Limited v. Commercial Union Assurance Company Limited, to determine whether a seaplane should be regarded as a "ship" for the purposes of the Merchant Shipping Act (as in force at the time). The court stated that in order to determine whether a craft should be regarded as a "ship" for the purposes of the Merchant Shipping Act, a court should look to a craft's "purpose" and stated that a "ship" requires a "hollow structure intended to be used in navigation (i.e. intended to do its real work on the seas or other waters, and capable of free and ordered movement thereon from one place to another)." In applying this rule to the facts of case, the court determined that a seaplane's real work is to fly as it was constructed for that purpose, and its ability to float and navigate short distances is merely incidental to that work.

Applying the same logic, it could be argued that an FLNG facility's main function is the production, storage and offloading of LNG or the receipt, storage and regasification of LNG and thus, although it may be capable of free and ordered movement across waters, the FLNG facility is not a "ship" because its navigational function is merely incidental to its main function.

Prelude's hull launch h from Geoje, South Korea in 2013. Photo from Shell.

As the world's first FLNG project, *Prelude* has a production capacity of 3.6mtpa LNG. Photo from Shell.

United States

Although the US has not acceded to the IMO conventions described above, recent US case law has considered what characteristics must be met for a craft to satisfy the meaning of the term "vessel." The term "vessel" is defined by the US Rules of Construction Act, 1 U.S.C. §3 as "every description of watercraft or other artificial contrivance used, or capable of being used, as a means of transportation on water."

In a recent 2013 case, Lozman v. City of Riviera Beach, Florida, the US Supreme Court considered whether the owner of a floating home was subject to maritime law on the basis that such watercraft was "capable of being used, as a means of transportation on water." In interpreting this language, the Supreme Court held that such phrase should encompass "practical" possibilities, not merely "theoretical" ones.

In other words, "a reasonable observer" must, when looking at any floating structure's "physical characteristics and activities … consider it [to be] designed to a practical degree for carrying people or things over water." The "floating home" in question had no self-propulsion but this, of itself, was not deemed to be conclusive evidence of "non-vessel" status. Additional facts such as a lack of rudder or other steering mechanism, unraked hull, a rectangular bottom 10in. below water level, no special capacity to generate or store electricity unless from land, rooms designed in a non-maritime style, and the fact that its windows were ordinary French windows were also considered by the US Supreme Court before ruling that the floating home did not meet the criteria to fall within the definition of "vessel" under the Rules of Construction Act.

In reaching its decision in the 2013 Lozman case, the US Supreme Court considered a number of earlier US maritime cases. Of particular note is a 2005 case, Stewart v. Dutra Construction Co., where the Supreme Court considered whether a dredge (in this case a massive floating platform used for silt dredging that moved using a towing system of anchors and cables) was found to serve a waterborne transportation function. The Supreme Court found that the dredge in question did meet the requirements to categories as a "vessel" and in so doing, acknowledged the following as important factors to consider in determining "vessel" status:

- water transportation need not be the "primary purpose" of the structure in question; and
- watercraft need not be in motion to qualify as a vessel so long as the structure is not "permanently attached" to the ocean floor or land (although exactly how long the facility would need to stay in one position to be classed as "permanently attached" was not ruled on in this case).

What constitutes a "seagoing vessel" or "seaborne craft" under the Bunker Convention/HNS Convention?

The Bunker Convention and HNS Convention define a "ship" to mean "any seagoing vessel and seaborne craft, of any type whatsoever." This definition appears all-encompassing but there is still significant scope to argue that certain FLNG facilities would fail to meet this requirement.

The meaning of "any seagoing vessel and seaborne craft" has not been judicially determined. Based on the Oxford English Dictionary meanings of the terms, the term "craft" is a generic term for a "boat or a ship." This simply leads us back to a requirement for movement on water as an essential criterion in order to fall within the meaning of either "seagoing vessel" or "seaborne craft."

Conclusion

FLNG facilities are an example of floating offshore craft that are often neither "ships" in the conventional sense of the word nor are they easily categorized as fixed offshore facilities in the same way as drilling rigs and various types of other offshore floating platforms. As this article demonstrates there is clear difficulty in defining the legal category into which FLNG facilities should fit.

A number of large-scale FLNG projects are currently either under construction or being proposed which (simply because of their scale) are more likely to exist solely as permanent facilities until final decommissioning. This can be contrasted with FPSOs converted from existing oil tankers and certain small- and mid-scale FLNG facilities converted from existing LNG tankers which, although stationary for extended periods, are (by their nature) designed to sail or navigate from place to place once production, regasification or offloading operations in a given area is complete. Although it is clearly more likely that an FLNG facility converted from existing tankers would be treated as a "vessel," consideration must be given to the specific modifications that have been made to the tanker on conversion to the FLNG facility. For example, if an FLNG facility has its motive power and steering disabled due to long term anchoring it may no longer be "practically" capable of carrying people or things over water.

Determining whether an FLNG facility will receive the benefit of limitations of liability for maritime claims will require consideration of the physical characteristics of the facility and the jurisdiction in which it is employed. As this article highlights, such a determination will not be black and white and will involve an assessment of how the applicable regime defines a "ship" or a "vessel" and the unique attributes of the relevant FLNG facility. OE

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***Paul Greening** is an Associate at Vinson & Elkins and is based in Hong Kong. His practice focuses on international energy, utilities and infrastructure projects. Greening earned a LL.B with honors and a B.E (Chemical) with honors from the University of Melbourne, Australia, in 2005. Greening is dual qualified in both England and Wales and Australia, and he currently practices English law in V&E's Hong Kong office.*

Developments in the natural gas and liquefied natural gas (LNG) industries are putting new demands on LNG shipping, triggering new specialized LNG carriers. Lars Petter Blikom sets out why.

Enter the specialized LNG carrier

Photo from DNV GL.

LNG shipping is in many ways a mature and established industry; up until now LNG ships have had a fairly standard design. At the end of 2013, the global LNG carrier fleet counted 357 ships, and another 108 ships were on the yard order books.

Despite being built over a period of almost 40 years, these ships haven't changed much. They have two choices of cargo tanks; membrane tanks or spherical tanks, and they have three choices of propulsion machinery; dual fuel diesel electric (DFDE), slow speed diesel/gas direct drive, or gas fueled boilers and steam turbines.

Aside from tanks and machinery, they are all generally the same. Size-wise they also follow the standards of the industry, which have evolved somewhat over the past 40 years as the "standard" size has grown from 125,000cu. m, through 137,000cu. m and 145,000cu. m, to today's size of about 160,000cu. m.

A ship built in accordance with a standard size and specification has many benefits. For one thing, it makes the ship itself a commodity. When every ship is the same and it can do the same job, it allows for the trading of the ships themselves—an activity ship owners are quite fond of. There is also an operational benefit to having standard ships; all the ships can load and unload at

all the world's export and import terminals. This creates flexibility in shipping, opens up opportunities for portfolio optimization and cargo diversion, and establishes a "cargo size" as a tradable volume.

Yet, changes in the natural gas and LNG industries will inevitably lead to a rethink of LNG ship design. It seems clear that the standard ship is not always the best option, and often it is not even a viable option.

Take, for example, the long term trend in the LNG industry for LNG export plants and import terminals to move to offshore locations. In benign waters, these plants and terminals can still be served by standard ships, but as soon as wave heights exceed a couple of meters, special purpose vessels will be necessary. They may need dynamic positioning capability for safe berthing and station-keeping, and they may need special connection arrangement for tandem offloading systems.

LNG supplies are also needed now in new, more challenging areas, such as the Arctic. LNG carriers serving LNG plants here will have to be built according to ice class rules. This means reinforced steel plates in the water line, more engine power, propellers able to break ice, special hull shape, and various other properties not offered by the standard LNG carrier.

Another driver for new ship design comes from the shift in LNG being used historically mainly for power plants, industry, and domestic heating and cooking in areas, with dense gas distribution grids, to off-grid applications in the future. Such applications include power generation in areas with no distribution grid, isolated industrial complexes, islands, and also transportation, where LNG and compressed natural gas (CNG) are being widely adopted in many markets.

For all these applications, natural gas eliminates most local emissions, contributing significantly to improving air quality—a growing problem for emerging Asian cities. Making natural gas available to these consumers requires a different supply chain than exists in the natural gas industry today, and there will be new requirements also to the ships serving this supply chain in the future.

We will see a greater demand for small- and medium-size ships. We will see increased use of flexible hoses for loading and offloading, which again drives a need for new connection systems, and we will see use of a wider selection of LNG containment systems, driving new operational requirements to pressure and temperature control, gas quality, etc.

LNG is gaining traction as a marine fuel, and within a few years we expect to see LNG bunkering going on in all the big ports around the world. This bunkering process will have to be served by special-purpose LNG bunkering ships and barges. These bunkering ships will not be very different from small LNG carriers, but they will have some additional features, such as dynamic positioning capability for efficient mooring, a special bunkering arrangement with either flexible hoses or loading arms, and additional systems for vapor return and cargo pressure control.

As a lot of the future growth in natural gas demand comes from power production, both small and large scale, it doesn't come as a surprise that floating LNG power barges/ships emerge. By having LNG storage tanks, re-gasification capability, and a power plant onboard, the unit can supply electricity instead of gas to shore, a great advantage in many areas, e.g. those that have limited land area available for accommodating future power sources.

There is also increased focus on providing ships in port with power from shore—referred to as cold-ironing—and LNG power barges could be a good alternative to this practice in many ports. Again, a standard LNG ship can't be used for this, as it will face a whole set of new requirements, spanning regulatory, operational, technical, and commercial aspects.

Over the coming years, global energy markets will change and adapt to meet future requirements for reduced carbon footprints and less local pollution. Natural gas is the cleanest of the fossil fuels, and is expected to constitute a significant share of the global energy mix for years to come. But in order to make sure we maximize the environmental effects of natural gas, it is important to utilize natural gas in applications where even cleaner options are not available.

For the industry to reach these customers, it will be necessary to redesign business models and supply chains for natural gas and LNG. This means new concepts in ship design. These are already materializing and the shipping industry is responding by designing and ordering new types of ships. So the question is not really whether this will happen, but how quickly? OE

***Lars Petter Blikom** is Segment Director for LNG at DNV GL, with global responsibility for business development within the LNG industry, covering both classification of ships, and advisory services. Lars Petter studied for an MSc degree in marine technology from NTNU before joining legacy DNV.*

Photo from DNV GL.

Solutions

Expro ExACT

The Expro ExACT (Expro annulus-operated circulating and test tool), a newly designed drill stem testing tool, offers flexible application to fit with a range of downhole operational conditions and objectives. The new tool is suited for gas wells and deepwater markets. Rated at 15,000psi and capable of operating in temperatures of up to 400˚F. ExACT features minimal fast-cycling to position the ball and ports in the required position, shortening times between cycles. Expro deployed the ExACT system in its first live offshore well for a tubing conveyed perforating "shoot and pull" in the Vermillion field in the Gulf of Mexico, following trial work onshore in Brazil last year. During its deployment, TCP guns were fired using a pressure-activated firing system set to detonate with 2400psi applied annulus pressure. Using a bespoke in-house software program, the ExACT tool was set up at surface to fully function downhole with applied annulus pressure between 1100psi-1400psi, leaving the desired firing head safety margin of 1000psi. Post-job analysis of gauge data verified that ExACT was operating within 50psi of calculated values in all tool positions.

www.exprogroup.com

Fanbeam laser radar sensor

Renishaw's Fanbeam laser radar sensor provides dynamic positioning to offshore support vessels and other marine structures. New control software adds greater performance and stability, increasing reliability of its single-target tracking capability, and allowing multiple operator stations for situations where control needs to be transferred between bridge personnel. The Fanbeam system uses position data to automatically hold vessels on station, and is typically the primary position reference during critical short-range operations, such as cargo container lifts from platform supply vessels. The system provides collision avoidance, gangway monitoring and docking assistance on vessels operating in crew supply, anchor handling tug supply, construction support, dive support, dredging and rock dumping capacities. Other applications include seismic source positioning for geophysical exploration vessels and positioning of mine detection equipment. Built for harsh environments, the system's operating temperature range is -13˚F to +158˚F (-25˚C to +70˚C), with a water/dust resistance rating of IP66, and is EN 60945/EN 609950-1:2001 compliant.

www.renishaw.com

Hoover Container Solutions' mud skip

Hoover Container Solutions added a new DOT- and DNV-certified mud skip / cutting box to its offshore product line for transportation and handling of hydrocarbon contaminated drill cuttings to and from offshore platforms. The units are designed and manufactured to DNV 2.7-1 / EN 12079 / DOT 49CFR176.340 standards and have certified slings and shackles. The roll-back lid reduces the risk of accidents. It is equipped with two 4-in. ports available for vacuum services and a pressure relief valve. The Hoover DOT-/DNV-certified mud skip / cutting box stands at 111in.-by-72.6in.-by-64.2in.

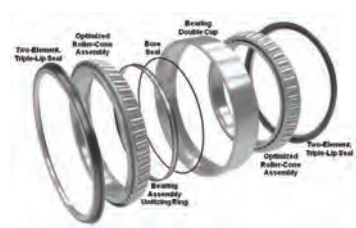
www.hooversolutions.com

Zeus NeoTem products

Zeus unveiled its new NeoTem fluropolymer line, featuring several extruded products that maintain electrical properties at high continuous service temperatures of up to 300° C / 572° F. Zeus developed processes to extrude ECCtreme ECA 3000 by DuPont into heat shrinkable tubing, insulated wire, drawn fiber and extruded tubing. Prior to NeoTem, polymer tubing and products had a maximum temperature threshold of 260° C / 500° F.

www.zeusinc.com

Timken Sheave Pac bearing assembly



Timken's Sheave Pac bearing assembly eliminate the need to re-grease the traveling block or crown block on oil rigs. The Sheave Pac assembly is designed to run an entire operating cycle between rebuild without the need for re-lubrication or additional maintenance. Due to its seal, the Timken Sheave Pac alleviates the need to re-lubricate the crown and traveling blocks above the rig platform job. The Sheave Pac assembly easily interchanges with current industry-standard bearing assemblies and seals.

www.timken.com

Activity

Pemex retreats from Repsol

Petróleos Mexicanos' (Pemex) Board of Directors unanimously voted to sell its 7.86% stake of Spanish oil company Repsol, the state-owned firm announced 4 June. Pemex expects to net US$900 million as a result of its decision, selling the shares for $27.36, up from the 2011 purchase price of $27.16. Citibank and Deutsche Bank are managing the transaction, which is expected to close 5 June. Its exit was due to low stock returns, Pemex said, while also expressing concerns over "differences with its corporate governance practices," saying that its investment did not include the "mutual benefits Pemex expected" from the "industrial alliance" that promised cooperation in upstream and LNG operations, with Pemex maintaining a 5-10% stake. Following Mexico's historic energy reform, the divestment would free up funds for projects and investments with higher domestic economic value, Pemex said. Under the reform, Pemex will be able to partner with companies for the first time since 1938.

Pemex CEO Emilio Loyola, right, with Total CEO Christophe de Margerie. Photo from Pemex.

Marathon keeps UK North Sea assets

The sale includes Marathon Oil-operated *Alvheim* FPSO. Photo from Marathon.

Marathon Oil announced it is no longer marketing its UK business after agreeing to sell off its Norwegian unit, Marathon Oil Norge AS, in a US$2.1 billion cash deal to Norway's Det norske oljeselskap ASA. The sale includes the Marathon Oil-operated *Alvheim* floating production, storage and offloading (FPSO) vessel, 10 company-operated licenses and a number of non-operated licenses on the Norwegian Continental Shelf in the North Sea. Once the transaction is completed, Det norske will have 202MMboe of 2P reserves, including the operated Ivar Aasen development and a stake in the Johan Sverdrup development project.

Ramboll buys Apply Altra

Denmark's Ramboll Group acquired Apply Altra in Aberdeen effective 2 June. The formal change in ownership was cemented with the immediate change of Apply Altra's company name, to Ramboll Oil & Gas. With presence in Norway, Denmark and now also the UK, Ramboll covers all sectors in the North Sea. "This is a strategic move for Ramboll," says Trond Helland Bynes, Executive Director of Ramboll Oil & Gas. Revealing Ramboll's underlying interests, Bynes commented that "Aberdeen is the number one city for offshore oil and gas in the UK sector of the North Sea." Under the Ramboll name, the former Apply Altra will continue to deliver facilities engineering capability to the oil, gas and renewables industry.

Peak Well Systems opens Dubai tech center

Specialist downhole tool provider Peak Well Systems has opened a new technology center in Dubai to accommodate regional technical sales and engineering teams for improved customer reach, as well as a large assembly and testing workshop facility for after-sales support. Peak Well Systems will also maintain a large inventory of rental tools in Dubai for rapid mobilization of advanced well intervention equipment to customers throughout the region. The opening of the Dubai Technology Center coincides with the upcoming market launch of Peak's ISO-14310 V3-rated SIM+ Plug Systems, a range of high performance flow control technologies.

Hanøytangen Rig Services partnership launched

Three Norwegian offshore service companies, Bergen Group, Semco Maritime, and Apply Rig & Modules, have joined forces to setup a new partnership, Hanøytangen Rig Services. The company will offer in-house front-end engineering, project planning, and management, on reclassifications, upgrades, and modifications, including installation and testing. The partnership will be led by a team consisting of representatives from each company.

INPEX opens Oslo office

Japan's INPEX Corp. created a wholly-owned Norwegian subsidiary, INPEX Norge AS, opening its first office in Oslo. Through its Norwegian office, INPEX will promote oil and natural gas exploration and production activities in the region. The company said this move is a part of its growth strategy, which includes expanding its portfolio of worldwide exploration activities.

Spotlight

By Audrey Leon

Newpark Drilling Fluid's new North American leader focused on domestic growth

In October, Newpark Drilling Fluids named Phil Vollands president of North America. Vollands is focused on growing the business and positioning Newpark Drilling Fluids as the leader in water-based fluid technology.

Vollands has plenty of industry experience. Before coming to Newpark, Vollands spent several years at Weatherford and over a decade with Varco (now National Oilwell Varco), moving to the US in 1996. He served as Varco's vice president of marketing and strategic planning. Prior to his stint with Varco, he worked as a wireline logging engineer in Canada and the North Sea after graduating from Oxford, where he received a BA and an MA in engineering science.

"We're a growing company. We can be strategic about where we focus and apply resources to gain market share."
Phil Vollands

The job at Newpark Drilling Fluids appealed to Vollands for several reasons, he explains.

"I was looking for a company that had a strong sense of mission, and in Newpark Drilling Fluids, I found a company that was committed to driving technological change in an environmentally-friendly way," Vollands says. "Newpark Drilling Fluids is a pure play. We live and die by how well we perform. That has fostered a performance-oriented culture."

Vollands is particularly proud of the technology center Newpark Drilling Fluids opened in 2013. The Newpark Technology Center – located on an 11-acre tract of land in Katy, Texas – spans 102,685sq ft, of which 37,000sq ft is devoted to research and development space.

The facility comes equipped with a field testing and services lab, designed to optimize formulations during operations. The facility is also home to the Downhole Simulation Cell, a drilling simulator that replicates downhole conditions.

"The Newpark Technology Center is second to none in the area of drilling fluids," Vollands says. "We have multiple labs, and enormous capabilities in terms of what we can do. We can give specific, tailor-made drilling fluid programs on the basis of customer input, through samples and cuttings."

"It's a great training facility. We have customers come through there," he says.

In his new role Vollands has several goals in mind. One is to continue to focus on its high-performance, water-based fluids line called the Evolution system.

"High-performance, water-based technology is taking off in all areas of North America," he says. "The Evolution System saw a quarter-on-quarter increase of 34% in 1Q 2014. We're drilling faster and further."

Vollands continued, saying: "It's all about improved performance, but it is also about doing what makes sense for the environment, rather than using diesel-based fluids, the old technology."

Domestic growth is also on Vollands long-term agenda, he explained, saying: "We're a growing company. We can be strategic about where we focus and apply resources to gain market share."

And Newpark Drilling Fluids is definitely looking to grow its market share in the Gulf of Mexico.

Newpark's product line also includes synthetic drilling fluids, which Vollands called a standard in the Gulf of Mexico. "It will be interesting to see what happens in the future there," he says. "There's certain advantages to water-based fluids including how they handle gas, the thermo properties and the lack of compressibility."

And indeed, Vollands believes that his company has plenty of room for future development. "I came from Varco where the top drive was deemed a huge breakthrough. PDC Bits, a huge break through. Automation, a huge breakthrough. Why wouldn't we think that through focused application of technology that drilling fluids wouldn't offer another major breakthrough? I think we're starting to see that." **OE**

The Newpark Technology Center. Photo from Newpark Drilling Fluids.

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Numerology

300MW is the combined capacity of the floating wind development planned for 2012 by Japan's Hitachi Zosen and Norway's Statoil. ▶ See page 21.

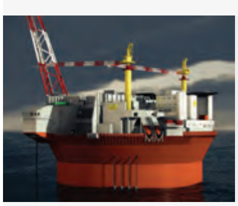
100years The amount of time Shell has been operating in Malaysia. ▶ See page 38.

7.5%

The offshore royalty rates in Tanzania, as defined by the new model production sharing agreement. ▶ See page 58.

19 discoveries have been made to date in the BP-operated Block 31 off Angola. ▶ See page 46.

13,300km The amount of seismic survey China's BGP Inc. shot of the Morondava basin off Madagascar. *(Source: BGP Inc.)*

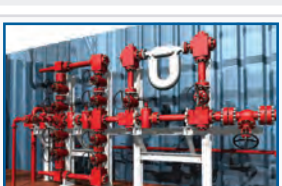


174MMbo is the estimated amount of reserves in the Goliat field. ▶ See page 16.

2500-tonne

The total weight of the Quad 204 redevelopment. ▶ See page 44.

158 wells have been drilled off Ireland over the last 50 years, with just a handful of finds. ▶ See page 34.



12-14 months **The long-lead MPD infrastructure was permanently built into the rig, enabling it to rapidly transition from "open to atmosphere with RGH" to full MPD capability, sparing 12-14 months in future rig up time.** ***(Source: Weatherford)***

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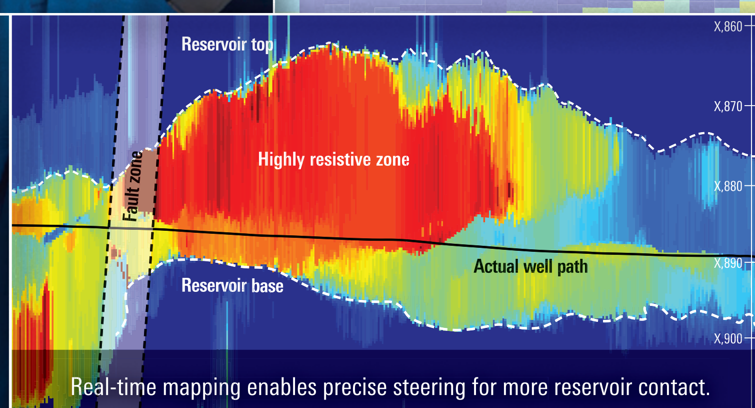

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