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Intelligent Oilfield

Offshore Engineer • March 2015

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Feature

Intelligent Oilfield

ON THE COVER

Long-awaited. In mid-February, Statoil and partners reached a final investment decision on the 2.35 billion bbl Johan Sverdrup field, located in the Norwegian North Sea. Discovered in 2010, the field's development is a major success given the current reduced CAPEX climate. Wood Mackenzie recently valued the field at US$11.2 billion.

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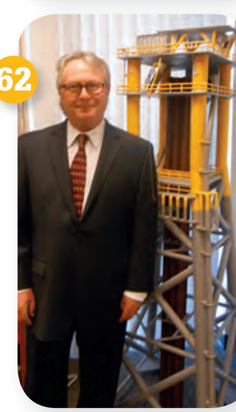

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“I was very interested to hear the industry leaders’ views on future developments in North Sea.

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Spotlight on New Zealand

Audrey Leon takes a look at recent exploration efforts offshore New Zealand.

The Maari wellhead platform in the Taranaki Basin. Image from Arup.

What's Trending

Ups and downs

- **Shell to return to Arctic**
- **Caribbean FLNG delayed**
- **Repsol in Talisman takeover**

People

Newman steps down

Transocean President and CEO Steven Newman resigned from the company in February. Ian Strachan, Transocean's chairman, will serve as interim CEO until a permanent replacement is found.

Voices

Tech driven. With the adoption of digital oilfield technologies, OE asked:

Are processes in place to fully utilize digital oilfield technologies, and if not what more needs to be done?

From predictive intelligence and diagnostics through to wireless, remote monitoring and greater intelligence subsea, digitizing oilfield technologies gives operators more knowledge on their offshore reservoirs than ever before. Yet, it's not just about technologies. It's about how we create a collaborative environment for reporting, monitoring and information sharing and how we capture value from real-time information. It's only through the integration of people, processes and technology that we can truly create the digital oilfield. There's always room for improvement and we must never stand still.

Ottar Vikingstad, Vice President Global Sales, Roxar, Emerson Process Management

The industry has done a great job of deploying digital control technologies to improve operational efficiencies and overall safety. As the industry continues to expand its use of Ethernet-based control and communication networks, protecting those networks from cyber security threats becomes absolutely critical. A previous best practice was to protect the network from outside attacks through firewalls. While external threats are still a concern, industry research shows that internal sources actually make up more than 60% of all security threats. A layered security approach, like Defense in Depth, is an ideal way to help contain security issues.

Tim Wallaert
Director, Oil and Gas Solutions, Belden

Digital technologies could be better utilized to track real-time reservoir conditions – particularly in the case of multiphase sampling and the accurate capturing of fluid properties that are so vital to flow measurement and flow assurance. Too often in the past, manual-based processes and lengthy waits on laboratory results have characterized such processes. There's a need for real-time, multiphase sampling information direct from the wellhead. Digital technologies are playing a vital role in achieving this.

Eivind Gransaether
CEO, Mirmorax

The oil and gas industry has made enormous strides in the embracing of digital technologies but more needs to be done. Nowhere is this better seen than in gas lift where operators are often dependent on wireline interventions to alter injection rates (with all the accompanying risks) and have little information on pressures and temperatures at the point of gas injection. Against the backdrop of low oil prices and the need to increase recovery, the digitization of gas lift technologies can't come fast enough.

Ian Anderson
Chief Operating Officer, Camcon Oil

The infrastructure of digital oilfield technologies is more advanced in the subsea and downstream segments of the global oil and gas market than in the upstream segment. Before processes can align, the gaps between a contractor's specifications and an operator's demands for increased data quality, reliability and accuracy must be closed. To increase cost-effectiveness and enable automation and optimization, the industry needs to continue its efforts to standardize initial designs and to increase modularity. Investment in digital infrastructure for smart sensors is essential in reducing operational costs, eliminating the need for upgrades, enabling enhanced data management and ensuring success with integrated operations across rig fleets.

Håkon Vidar Straume
Product Line Director, Data Acquisition
NOV

Few companies have aligned their processes to fully utilize digital oilfield technologies and thus maximize the return from their investments. Collaboration rooms are a great example of this. How many of these rooms have been designed by AV specialists with little regard to the processes expected to be run in the room?

In terms of what more needs to be done; taking a more holistic view to incorporate the people and process components of a business is always a good start. As is realizing that the implementation of new technologies is a "journey." The value from the technology is not fully realized once the implementation project is over. The business needs to embrace change – become a "learning organization" that understands technology will change it over time and dynamically adapt to that change.

Jan-Erik Nordtvedt
SPE Intelligent Energy Programme Chair 2014
and President and CEO, Epsis

The digital oilfield is a journey, not a single project. Oil and gas operators go through phases of implementation to fully realize all the benefits of the technologies enabling this vision. Not all companies are in the same stage of the journey. As oil and gas operations move through the digital oilfield journey, processes - such as technical competency, access guidelines, security policies, standards adoption and workflow automation, among others - are required to enable the effective deployment of intelligent sensors and equipment, a robust and secure communication infrastructure, pervasive visualization systems and analysis tools to turn field data into actionable knowledge.

Luis Gamboa
Global Oil and Gas Market Development Manager, Rockwell Automation

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ThoughtStream

Professor Alex Kemp, University of Aberdeen

Low oil prices and activity on the UK Continental Shelf

It is widely accepted that the UK Continental Shelf (UKCS) is a high cost petroleum province by world standards. The collapse in oil prices from over US$100/bbl to less than $50 can thus be expected to have a substantial effect on activity levels.

It should be recognized that even before the price fall investment in new fields and projects was set to fall significantly from 2015 onwards. This is a reflection of the near completion of a few very large investments with rampant cost inflation.

At current oil prices, many new projects which would have been acceptable at $100 are no longer viable. The upstream industry in the UKCS ended 2013 in a negative net cash flow position. This will have become worse in 2014. Given this, and the increased capital rationing, investment budgets have been significantly cut. Studies undertaken by the present writer indicate that if a real oil price of $70 for investment screening were to prevail rather than one of $90 in real terms (i.e. with both increasing at 2.5%/yr) over the period to 2050, cumulative production would be around 12 billion boe, rather than 15 billion boe, and field investment would be £81 billion at 2014 prices, rather than £122 billion.

But this somber prospect need not become a reality, even if oil prices remain relatively low. The outlook can be transformed through a combination of changes in government policy and self-help within the industry. The Wood Review and studies undertaken as a consequence of the current environment both point the way to the achievement of substantial new activity.

Research undertaken by the present writer indicates that, if production efficiency could be increased from the present 60% to 70% through a combination of more effective regulation by the new Oil and Gas Authority and enhanced implementation of the relevant measures by the industry, the resulting increase in production and revenues over the next few years could be very substantial.

It had become clear well before the price collapse that the present tax system in the UKCS was no longer appropriate for the attainment of maximum economic recovery. This has now been recognized by the UK government, and the current debate is concerned with the extent of the reforms which are necessary.

Currently, the UK government is giving priority to the introduction of a basin-wide investment allowance against the Supplementary Charge. Research by the present author indicates that, if this allowance were implemented at a rate of 50% or 62.5% the result would be a substantial increase in investment totalling many £ billions in the period to 2050. There would be a win-win situation for both the industry and government as the allowance would only be given for new investment. There would be a significant net increase in longer-term tax revenues as well as capital expenditure and production.

The industry is pressing for a reduction in the rate of Supplementary Charge from its present level of 30%. The case for this has become stronger recently as a result of the price collapse and the consequent negative cash flow position of the industry. A combination of a substantial investment allowance and reduction in the headline rate of the Supplementary Charge could significantly improve the investment environment for new field developments, incremental projects and exploration.

With respect to self-help, the most obvious response to the price fall is through cost savings. Many companies have already announced redundancies and reductions in contractor rates. But little attention has been given to the further consequences of achieved cost savings. Research by the present author indicates that, if the industry effected cost savings of 15% applicable to both investment and operating activities the result could be that over time significant numbers of new fields and projects could become viable when they were uncommercial before the cost savings. In fact, over time the investment expenditures relating to new projects could exceed the value of the cost reductions effected in projects which were in any case viable at the relatively low price.

It follows from the above that a combination of targeted tax reliefs, more effective regulation, and carefully designed and implemented cost savings could produce a substantial increase in activity relating to investment expenditure, operating expenditure, production, and tax revenues. A challenge will be to effect the necessary cost savings in such a manner that production efficiency is still enhanced, and the expertise within the sector (oil companies and supply chain) continues to be deployed to best effect. OE

__Alex Kemp__ is currently Professor of Petroleum Economics and Director of Aberdeen Centre for Research in Energy Economics and Finance at the University of Aberdeen. He has published more than 200 papers on petroleum economics. He was a specialist adviser to the UK House of Commons Select Committee on Energy in 1980-1992, and in 2004, and 2009. From 1993-2003, he was a member of the UK Government Energy Advisory Panel. He was awarded the OBE in 2006, for services to the oil and gas industries. He wrote The Official History of North Sea Oil and Gas, published in 2011, in two volumes.

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Global E&P Briefs

A US issues proposal on Arctic drilling regulations

The US Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM) released proposed regulations for exploratory drilling activities on the US Arctic Outer Continental Shelf. The regulations focus solely on offshore exploration drilling operations within the Beaufort Sea and Chukchi Sea planning areas.

According to BSEE, the proposed rule seeks to address issues relating to design, development of an integrated operations plan, the ability to deploy source control and containment equipment, and procurement of – and the ability to deploy – a separate relief rig in the event of loss of well control situation, the ability to monitor and respond to ice conditions and other adverse weather events, the ability to effectively manage contractors, and the development and implementation of an oil spill response plan.

B Supermajors team up for Gulf exploration

A team of supermajors led by Chevron are exploring and appraising 24 jointly-help offshore leases in the northwest portion of Keathley Canyon in the deepwater Gulf of Mexico. The deal between Chevron, BP, and ConocoPhillips, covers the Tiber and Gila discoveries, and the Gibson exploratory prospect. Further exploration and appraisal will be done of these leases, in addition to evaluating the potential of a centralized production facility, which would provide improved capital efficiency, similar to Chevron's Jack/St. Malo project. Chevron recently acquired an interest in Tiber and Gila from BP. Chevron, BP and ConocoPhillips already held interests in the Gibson prospect.

Noble bites Madison dust

The US Gulf of Mexico deepwater Madison well has been plugged and abandoned after failing to find commercial hydrocarbons. Operator Noble Energy drilled the well to a total depth of 16,850ft, in 7149ft water depth, on Mississippi Canyon 479. It reached the targeted Upper and Middle Miocene objectives. Noble Energy has 60% working interest with partner Stone Energy Offshore holding the remaining 40%.

D Explosion kills six off Brazil

BW Offshore confirmed that an explosion on the *Cidade São Mateus* FPSO, offshore Espirito Santo state, Brazil, has resulted in six dead, three missing. There were 74 workers onboard at the time of the explosion, which happened at 12:50pm local time on 11 February.

The explosion is thought to be caused by a gas leak in the pump house. BW Offshore says production on the unit was shut in and shut down. Before the blast, the FPSO was working the Camarupim and Camarupim Norte fields, about 120km offshore. The FPSO began production at Camarupim in 2009. The concession is operated by Petrobras (100%) and the Camarupim Norte concession is a partnership between Petrobras (75%) and Ouro Preto Energia (25%).

E Campos basin find for Petrobras

Petrobras has made a new heavy oil discovery in concession BM-C-35 (exploratory block C-M-535), in the Campos Basin post-salt layer. The discovery was made while drilling well 1-BRSA-1289-RJS (ANP nomenclature) / 1-RJS-737 (Petrobras nomenclature), informally known as Basilisco.

The well is about 143km from the city of Armação dos Búzios, on the coast of Rio de Janeiro state, in 2214m water depth. The accumulations consist of heavy oil and can be found in two different reservoir depths, at 3190m and 3521m.

Petrobras, which is operator with 65% interest, will now with its partner BP (35%) assess the extent of the discoveries, as well as the concession's exploratory potential.

F Carribean FLNG delayed

Belgium's Exmar announced that operator Pacific Rubiales Energy will delay start-up for the Caribbean FLNG project offshore Colombia, which was to be the first operational FLNG facility.

Exmar said that Pacific Rubiales attributed the delay to "unfavorable energy market conditions," but that the company remains committed to the project. Exmar said the company plans to take delivery of the FLNG vessel in 2H 2015.

"The uncertainty in oil prices continues and although we believe that oil prices will recover, we are taking a cautious view on the timing, reducing both our costs and our 2015 capital budget to match expected cash flow," said Ronald Pantin, CEO of Pacific Rubiales Energy.

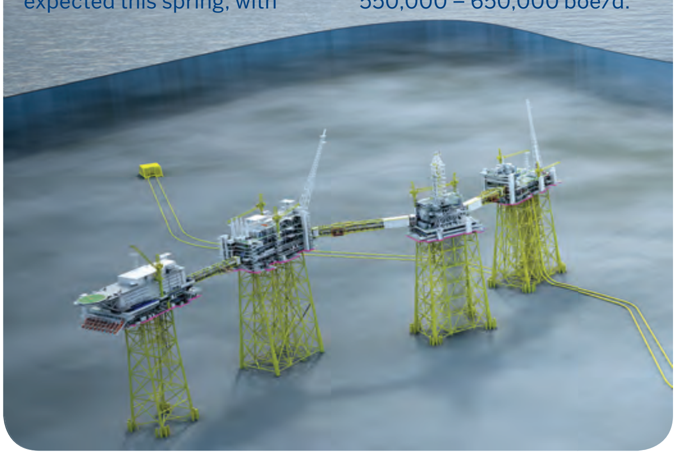
G Johan Sverdrup plan submitted

Statoil and its partners have submitted their development plan for the Johan Sverdrup field to the Norwegian Ministry of Petroleum and Energy.

The US$15.4 billion phase one plan for the giant Johan Sverdrup field comprises four bridge-linked platforms, with power from shore, and three subsea water injection templates. Approval is expected this spring, with first oil expected for the end of 2019.

The full field development cost is estimated at $22.4-28.9 billion, unlocking up to 3 billion boe.

Development phase one will have a 315,000-380,000 b/d production capacity, with recoverable resources projected at 1.4-2.4 billion boe. Full production is estimated at 550,000 – 650,000 boe/d.



H Providence gains ground

Providence Resources has reached agreement with a proposed farm-in on its Barryroe asset, in the Celtic Sea offshore Ireland. Providence plans for early production at the Barryroe field of about 30,000b/d, using a small wellhead platform and floating storage and offloading vessel, however the project has been waiting for development funding.

Providence Resources has also acquired Chrysaor's Irish subsidiary, Chrysaor Exploration & Production Ireland. The deal sees Providence take over 26% interest in the Spanish Point field, in Frontier Exploration License (FEL) 2/04, offshore Ireland, and 26% stakes in both in FEL 4/08 and FEL 1/14. The licenses cover an area of about 2000sq km about 175 km off the west coast of Ireland, in Quadrant 35 in the northern Porcupine Basin.

I VAALCO continues at Etame

VAALCO Energy began first production from the Etame 10-H well, at approximately 3000 b/d, on the Etame Marin block, offshore Gabon.

Etame 10-H, the second well of a six-well development drilling campaign, was drilled with Transocean's Constellation II jackup rig to a measured depth of 3144m, while intersecting more than 180m of high quality reservoir within an oil-bearing portion of the Gamba sand.

J Sterling farm-in on Mauritania

Sterling Energy has agreed to acquire a 40.5% stake in the Block C-3 production sharing contract (PSC) offshore Mauritania from Tullow Oil's Mauritanian subsidiary.

The Block C-3 PSC is in the first phase of the exploration period. The block covers about 9800sq km which Tullow acquired 1600km of 2D seismic, which will be processed during 2015.

Tullow currently holds a 90% stake in the license with Société Mauritanienne Des Hydrocarbures Et Du Patrimoine Minier (SMH) holding the remaining 10%.

K Noble suspends Israel investments

Noble Energy is suspending any further investments in the expansion of Tamar, and initial development of Leviathan until regulatory issues are resolved with Israel. Noble President and CEO David Stover said the recent decision by the Antitrust Authority to not submit the agreed consent decree for final approval was a direct reversal of their prior agreement, and another example of the uncertain regulatory impairment in Israel. An agreement was reached in 2014 between Noble Energy, its Leviathan partners, and the Israel Antitrust Authority for the consent decree that included the divestiture of the Tanin and Karish gas fields, in an effort to support competition of supply, and move forward the development of Leviathan.

Leviathan is Noble's largest exploration discovery in its history with an estimated 19Tcf of gross natural gas resources, representing the largest deepwater natural gas discovery in the world in over a decade. The Leviathan project is located on the Rachel and Amit licenses off Israel in 5550ft of water. Noble anticipated that Leviathan's first phase would be approved in 2014.

L Nasr field first oil

First oil from the Nasr oil field, 130km offshore Abu Dhabi, has begun, according to Japan's INPEX.

First production has been achieved through existing facilities – the Abu Al Bukoosh (ABK) and Umm Shaif oil fields, adjacent to Nasr. From here, oil is piped via and existing pipelines to Das Island, and then on to international markets.

Full field development work, which will see production increase to a peak rate of 65,000bo/d, is in progress.

The field is being jointly developed with Abu Dhabi National Oil Company (ADNOC), BP and TOTAL.

M Goliat en-route

Eni's Goliat cyclindrical floating production, storage and offloading (FPSO) platform, built in South Korea and now destined for the Barents Sea, has finally been loaded ready for transport to Norway.

The 107m-diameter Goliat platform, which will produce the first oil from the Barents Sea, in what will be the world's northern-most offshore oil field, has been loaded on to the *Dockwise Vanguard* – the largest marine transport vessel in the world.

It will transport the FPSO around the southern tip of Africa, before heading to Hammerfest, Norway, on a journey expected to take around 60 days.

Tie-in operations and preparations for production, in field, will take place during the summer, with first oil scheduled for mid-2015.

N Meo eyes Beehive

MEO Australia is considering drilling on its Beehive oil prospect after an international exploration company executed an option that will allow it to farm-in to any of MEO Australia's WA-488-P, AC/P50 and AC/P51 permits off northwestern Australia.

The move could see the farminee firm take 30% interest in WA-488-P, in the Petrel sub-basin, containing the significant Beehive prospect, and fund 30% of future spending on the permit. It could also take an additional 10%, which would cover the costs of a 3D seismic survey over the Beehive prospect, and a further 40% to cover drilling costs on the proposed Beehive-1 well, leaving MEO with 20% participating interest.

MEO gas made analogies with Beehive, which contains two prospects, in the Lower Carboniferous and Ordovician, to the Ungani oil discovery in the Canning basin, the giant Tengiz field in the North Caspian basin and the Buried Hill oil fields in the Tarim basin of China.

The company says Beehive could contain up to 598 MMstb P50 prospective recoverable resources in the Carboniferous and 328 MMstb in the Ordovician. The company says the two prospects could be tested with one well and is "ready to drill."

Contract Briefs

BP, Maersk enter 5-year training contract

BP and Maersk Training singed a five-year contract that will offer advanced training programs for BP's offshore drilling teams to be based in Houston.

Maersk Training plans to open a new state-of-the-art facility in Houston by 2016 that will feature highly interactive simulators replicating nearly every critical job on an offshore drilling rig.

BP will use the facility to train integrated offshore drilling teams – comprised of BP employees and contractors — in what it calls an "immersive simulation environment."

The Houston facility will include simulators for cyber drilling, vessel bridge, cranes and engine room, plus an emergency response room. In addition, Maersk Training will equip the facility for ship-handling operations to serve the maritime training market.

KANFA wins Cape Three Points work

Sevan Marine subsidiary KANFA won a letter of award for the engineering, procurement and construction (EPC) of four process modules for the FPSO *Yinson Production*.

The contract is expected to last 15 months and be worth about US$50 million. The FPSO will be deployed at the recently sanctioned Offshore Cape Three Points Block (OCTP), in the Tano Basin, about 60km offshore Ghana.

Eni selects TOOLS to supply Goliat

Norway's TOOLS has won a contract from Eni Norge for the provision of services and supplies to the Goliat FPSO, which has a planned production startup date in mid-2015.

The three-year contract, which has extension options, includes the provision of tools, pipes and fittings, transmissions, cleaning products and other supplies for the Goliat project.

ABB gets US$50 million Petronas FLNG contract

JGC Corp. awarded ABB a US$50 million contract to supply the electrical system for a floating liquefied natural gas (FLNG) facility, and the second to be owned by Malaysian oil and gas company Petronas, the PFLNG2.

Under the terms of the contract, ABB will support the optimization of the facility's electrical side by designing, manufacturing and supplying transformers, switchboards, motor-control centers and power management system.

In addition, ABB will also manage the installation of the equipment and ensure the electrical supply is integrated with the systems it is powering.

Wood Group bags Woodside contract offshore Australia

Wood Group Kenny has secured a contract with Australia's Woodside to provide the front-end engineering design (FEED) of the flowline system, and associated procurement support, for the proposed Greater Western Flank Phase 2 (GWF-2) development for the North West Shelf Project, offshore Western Australia.

The work scope includes engineering and procurement support services for the 16in. GWF-2 corrosion resistant alloy rigid flowline system, flowline end termination structures, inline tee assembly structures, mid connection structure and subsea tie-in spools.

The primary engineering focus of the GWF-2 flowline FEED is to develop the flowline system for the final investment decision planned for 2H 2015. ■

The 22,400-tonne Mariner jacket under construction at Dragados Offshore's yard in Cadiz, Spain.
Images from Statoil.

Constructing Mariner

The Mariner heavy oil discovery on the East Shetland Platform in UK block 9/11 will be one of the largest offshore developments on the UK Continental Shelf in more than a decade. Meg Chesshyre checks on its progress.

Construction for Mariner, one of the largest recent UK North Sea offshore developments, is in full flow. Some four different yards are all producing different elements of what will become the Mariner facilities, sitting in license 335, on the East Shetland Platform of the UK North Sea, approximately 150km east of the Shetland Isles.

The project is on schedule for first oil in 2017, and is expected to be in production for more than 30 years. Mariner was first identified on 2D seismic data acquired in 1977, which led to Union Oil picking up the license in 1980, and drilling the 9/11-1 well in 1981, discovering oil in both the Heimdal and Maureen sand members.

Since Mariner was first discovered, the field has been subject to a number of development studies and concepts by the different operators.

Since the P335 licence was awarded (1980) and the 9/11-1 discovery, five seismic surveys have been acquired, a further 18 wells have been drilled and the license has seen four changes in operator. The license equity history lists 12 companies that have been involved in the project with up to three partners at any one time. Statoil assumed operatorship from Chevron in 2007, with partners JX Nippon joining the group in 2012 and Dyas in 2013.

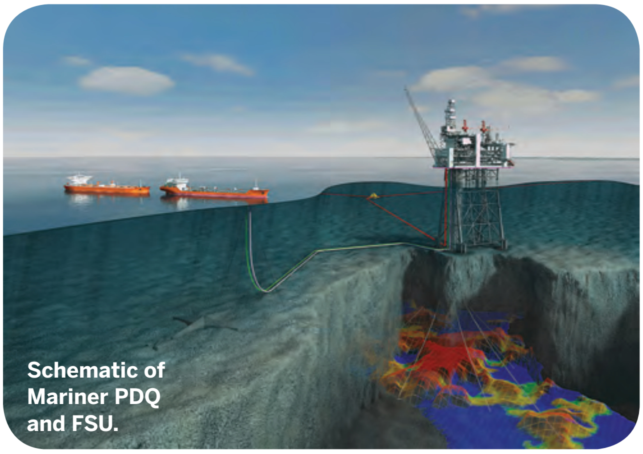
Statoil is the first company to put forward a development concept that addresses the complexities of the field, in particular imaging the Heimdal reservoir, reservoir management, recovery rates and project execution.

The field development concept includes a production, drilling and living quarters (PDQ) platform with a floating storage unit, together with a jackup rig assisting initially. In total this means a gross investment of more than US$7 billion for the project. The development will contribute to more than 250 MMbbl reserves and provide a long term cash flow over a 30-year field life. Improved oil recovery together with additional near field volumes, for example Mariner East and near field exploration, aim to extend the development beyond 30 years.

Construction

The load-out, transportation and installation of the 22,400-tonne jacket from Dragados' yard in Cadiz, Spain, in May/June will be one of the major milestones this year. Subsea, umbilicals, risers and flowlines installation will also take place this year.

Last summer, first steel was cut on the floating storage unit at Samsung and on the 36,000-tonne platform topsides at Daewoo Shipbuilding & Marine Engineering in



Schematic of Mariner PDQ and FSU.

Korea. Sailaway and installation of the topsides is planned in 2016. The Cat J jackup, designed to Statoil's specifications, to be owned and operated by Noble, is under construction at Sembcorp Marine's Jurong yard in Singapore.

Tackling Heimdal

The main, deeper (at about 1492m) Maureen reservoir is currently planned to have 17 producers and five water injectors, with first oil from the Maureen reservoir in 2017. The Maureen reservoir has 14º API gravity oil and an oil viscosity of 65 cP, with excellent reservoir properties. The reservoir itself is very well understood; it has a clear seismic response, can be correlated between wells and has good core recovery.

However, the shallower (1227m) Heimdal reservoir has long been considered the main challenge at Mariner and could, at least until recently, not be mapped seismically. The challenging nature of vintage seismic led towards a stochastic reservoir model. The Heimdal has 12º API gravity oil and an oil viscosity of over 500 cP, again with excellent reservoir properties. The current development strategy based on the stochastic model is pattern drilling using an inverted nine-spot pattern, which is planned to have 39 dual multi-lateral production wells and 32 water injectors. First oil from the Heimdal reservoir will follow on from the Maureen plateau to optimize plateau production.

In 2012, a full field broadband seismic survey was acquired, with final processed products were available in 1Q 2014. This applies the newest advances in acquisition and processing technology to obtain better imaging of the Heimdal sands. There has subsequently been a focus on integrating the new seismic data into a more deterministic reservoir model. A more deterministic model would greatly improve well planning, geo-steering and therefore optimize the Heimdal development, moving away from pattern drilling towards more target driven drilling. The improved image of the Heimdal sands and their distribution across the Mariner licenses on the new seismic data will ultimately be tested when drilling of the Maureen production wells starts in 2017.

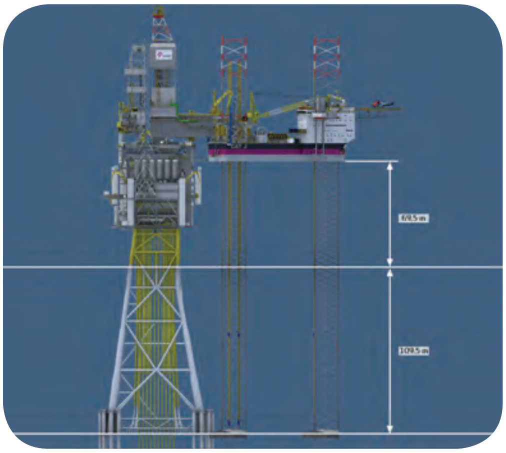
130-well program

Over the field's lifetime, as many as 130 well targets are planned. This will be a major factory, delivering one well per month in the first years of operation. Submersible pumps will be needed to bring the oil to the surface. Statoil's experience from its own heavy oil projects, like Grane on the Norwegian Continental Shelf and Peregrino in Brazil, has made a significant contribution here. The development of directional drilling, long horizontal wells and multi-laterals was crucial for Mariner's development, allowing increased exposure to the reservoir and the ability to reach more well targets. This technology was not available when Mariner was first discovered.

Drilling is planned to start in 2016. Odfjell has the platform drilling contract. The main Mariner platform will include a drilling rig and a well intervention and completion unit. The intervention and completion unit is an innovation that will allow Statoil to run completions and set submersible pumps without using the drilling rig. The wells will have sophisticated valves that automatically shut out reservoir zones with high water cut. In addition, the newbuild jackup rig will be located next to the Mariner installation, working through well slots on the platform for the first 4-5 years.

A contract for integrated drilling and well services on the Mariner field was awarded to Schlumberger Oilfield UK in December 2014.

Chris Andrew (left) vice president for asset management for Statoil in Aberdeen and Gunnar Breivik (right) MD for Statoil production UK and head of the Aberdeen office, in front of the Mariner jacket under construction at Dragados Offshore yard in Cadiz, Spain.



Schematic of Statoil's Cat J design rig currently under construction at Sembcorp Marine's Jurong yard in Singapore for use on Mariner.

A total 22 drilling and well services are included in the scope, including a logistics support responsibility that goes beyond the normal scope for similar Statoil contracts. The contract started in January 2015 and runs for four years, with options to be extended several times for further four-year periods. The contract with Schlumberger Oilfield also includes options for Bressay, another Statoil operated field on the UKCS, currently in the concept evaluation phase.

"Mariner is by all accounts a large and challenging project," says Gunnar Breivik, managing director of Statoil Production UK and head of the Aberdeen office. "When Mariner starts producing in 2017, it will be 40 years after the first seismic that identified the structure. The discovery well was drilled already in 1981. Several operators have worked hard on this project before us. We are proud to be the operator able to bring this field on stream, but we are building on decades of good work by many others."

Statoil is the operator of the Mariner field with 65.11% equity. Co-venturers are JX Nippon Exploration and Production (UK) (28.89%) and Dyas (6%). OE

Back to basics

Neil Duffin, President ExxonMobil Development Co.

Getting engineering back to basics isn't just about standardization anymore. Industry executives at the annual GE Oil & Gas summit in Florence advocated for simplicity in order to keep costs low and get projects done right. Elaine Maslin reports.

Back in the first half of 2014, capital discipline was a big fixture on the tables of oil executives globally. Then, over a period of six months, the oil price fell to its lowest in nearly six years.

The reasons for the fall in oil prices have already been well aired and the responses rapid – job cuts, swift and deep, running into the thousands, at operators and contractors.

Downturns have become a cyclical feature of the industry. So, many have been asking, how can the industry address this latest down turn in a way that means it comes out the other side stronger and more resilient – and not simply primed for the next cycle?

Engineering has come under the spot light as one of the areas that could be addressed, and it's not just about standardization. Neil Duffin, President ExxonMobil Development Co., says the industry needs to get its engineering "get back to basics" and get it right, up front. Engineering, he says, has been allowed to do its own thing too much.

Turning the tide around at ExxonMobil has involved a discussion around "minimum kit," but also around, where possible, designing one to build multiple, instead of re-engineering the latest design, he says. Re-calibrating how the industry engineers its projects will have the greatest impact on capital costs, he told GE Oil & Gas' annual meeting in Florence, early February.

How did we get here?

"When you look at how much money has been spent in our industry, the numbers are staggering," Duffin told the event – over US$800 billion was spent in 2014 in the upstream industry. As spending increased, so did engineering, procurement and construction (EPC) backlogs. "This has meant the industry has been struggling to keep up with demand," he says. "In some cases, industry has not enable to pull it off and costs have got out of control."

Also speaking at the event, Rod Christie, CEO Subsea Systems, GE Oil & Gas, cited figures published before the oil price plummet which say 64% of oil and gas upstream projects were facing cost overruns and 73% were running over schedule.

Quick stats

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

New discoveries announced

Depth range	2012	2013	2014	2015
Shallow (<500m)	75	74	64	1
Deep (500-1500m)	23	19	25	2
Ultradeep (>1500m)	36	34	12	2
Total	**134**	**127**	**101**	**5**
Start of 2015	135	125	90	-
date comparison	-1	2	11	5

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	11	452.75	4363.28
Deep	16	1616.00	2935.00
Ultradeep	50	15,843.25	19,173.00
United States			
Shallow	18	101.80	254.00
Deep	18	1219.27	1580.48
Ultradeep	26	3906.50	4020.00
West Africa			
Shallow	182	4803.82	23,572.05
Deep	45	5767.50	7930.00
Ultradeep	18	2135.00	2890.00
Total	**384**	**35,845.89**	**66,717.81**
(last month)	(398)	(37,822.89)	(69,237.81)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1177	45,074.12	628,316.23
(last month)	(1236)	45,354.59)	(620,138.46)
Deep	161	10,853.24	120,623.91
(last month)	(166)	(11,507.24)	(118,058.91)
Ultradeep	104	22,227.75	40,850.00
(last month)	(113)	(23,242.15)	(68,040.00)
Total	**1442**	**78,155.11**	**789,790.14**

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,232	(41,645)
Planned/ possible	24,574	(24,686)
	65,806	(66,331)
8-16in.		
Operational/ installed	81,420	(81,813)
Planned/ possible	48,923	(48,485)
	130,343	(130,298)
>16in.		
Operational/ installed	92,627	(92,693)
Planned/ possible	39,767	(39,013)
	132,394	(131,706)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	286	(285)
Under development	46	(44)
Planned/possible	336	(341)
	668	(670)
Fixed platforms		
Operational	9299	(9324)
Under development	85	(120)
Planned/possible	1370	(1399)
	10,754	(10,843)
Subsea wells		
Operational	4783	(4789)
Under development	378	(361)
Planned/possible	6564	(6569)
	11,725	(11,719)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	23,763.00	20,900.41	36,692.73	33,428.02	24,440.98	29,310.48	31,987.18
(last month)	(23,710.48)	(28,214.64)	(29,514.12)	(36,573.66)	(25,223.04)	(27,872.19)	(35,582.14)
Deep	481.00	4445.73	4375.97	3475.55	3155.96	6765.81	14,386.51
(last month)	(484.30)	(4343.62)	(4855.45)	(3510.66)	(3703.79)	(6566.83)	(13,724.76)
Ultradeep	2928	2368.31	2202.73	6182.92	6149.47	5053.15	9841.71
(last month)	(2928.00)	(2749.62)	(1869.95)	(4499.41)	(9190.33)	(10,453.02)	(9225.39)
Total	**27,172.31**	**27,714.45**	**43,271.43**	**43,086.49**	**33,746.41**	**41,129.44**	**56,215.40**

13 February 2015

As well as increasing costs, big back logs led to "softer issues," such as staff tending to move around companies a lot, creating "mismatched cultures," leading to projects that are not ready to execute when they come off the drawing board, Duffin says.

"There's nothing worse than a whole bunch of engineers together who have never worked before and who have all got their own ideas trying to work on an integrated plan and what you can end up is with a product you just can't execute," he says.

"It's not just engineering," he adds. "It's having people with execution capability sitting in the upfront piece in concept select and design so that what comes off the drawing board is actually something you can execute. That's not just our industry, look at car manufacturing. You don't just let the car designer design a car and send it to the marketer. I think we've slipped too far into letting engineering do its own thing."

Duffin also says there's been a tendency to take the last design and work from it for the next project, building in more space for safety reasons, adding addition equipment, more alarm systems, monitoring, etc.

"Before you know where you are you've added weight because you've got more cable trays running all over the platform and people forget that it doesn't take much so say you now need more people to work because you've got more equipment," he says. "You would think, because of advanced technologies, you would be going down in number of people, not up, but the more complexity you take offshore the higher the risk you are running."

Recalibration

"What can the industry do? We can simplify it (engineering), get to the minimum kit and work it from there. I can't belabor enough the importance of up front end engineering and getting it right. Sometimes there's a rush to get from engineering to execution. Where the industry has done that, in general, they've paid a very hefty price, particularly the more complex projects.

"If you get into execution and for whatever reason, whether it for socio-economic reasons, whether the engineering is just not the quality you are looking for and you have to re-engineer as you are construction, or civics works not right or environmental factors have changed the original principles design.

"Upfront engineering and concept select, if we as an industry can recalibrate that, back to the expertise we had before, we could make a big difference on our capital cost structure."

Duffin also says the industry needs to change its mindset towards engineering. "Within Exxon, we've got a discussion around minimum kit," he says. "Start with minimum kit and then justify what you have to add, not start with what you've got and tell me it's not economic then tell me what you are taking off, because in many cases it's not economics with what has been designed and I think we all know that. It's takes a different mindset."

Exxon has also been looking at a "design one build many" concept. "We've had opportunities where we are working with industry to say, if we spend the time up front, because we know we have multiples coming, let's deign that first piece of kit really well, get the engineering done, then get into execution so we can repeat it, and train the work force so that

Bernard Looney, chief operating officer production, BP

in the third and fourth cases the costs are drastically less," Duffin says.

Another area which has seen costs increasing is where developments are in remote locations, which see costs in mobilization, logistics, but also training at remote sites. Duffin suggests modularizing projects so that work can be taken to a site more hook-up ready, reducing complexities, manpower needs and training requirements on site.

Collaboration

Bernard Looney, chief operating officer production, BP, says the industry needs to focus on more collaboration "with a purpose." "The cost structure of this industry I believe was too high at $100/bbl, let alone at $50/bbl," he told the annual GE Oil & Gas meeting.

"That is calling for some radical changes in the way we do our business and the way we do that is around how we work with our suppliers."

Looney gave an example of where BP had worked with GE Oil & Gas to reduce down time on its deepwater drilling rig fleet. BP has about 16 deepwater drilling units globally, says Looney. "In 2012, we along with many in our industry suffered a lot of downtime from the blow out presenter," he told the event. "In 2012, we suffered about 600 days of downtime in our 16 rig fleet, the equivalent to two rigs being out of action for the entire year. We sat down with GE to try and halve that within two years. By working with GE we took that 600-day number down to 200 days. That's still too much, but that 400-day saving of waste is worth about half a billion dollars. Ideas like this will last a lot longer than sending you a letter asking you to take 10% out of your cost base." OE

FURTHER **READING**

Read more: Inefficient producers will be driven out - OE Digital
http://www.oedigital.com/component/k2/item/8135-inefficient-producers-will-be-driven-out

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	113	91	22	80%
Jackup	420	356	64	84%
Semisub	177	156	21	88%
Tenders	34	21	13	61%
Total	744	624	120	83%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	35	32	3	91%
Jackup	83	62	21	74%
Semisub	27	22	5	81%
Tenders	N/A	N/A	N/A	N/A
Total	145	116	29	80%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	17	10	7	58%
Jackup	119	106	13	89%
Semisub	37	30	7	81%
Tenders	24	12	12	50%
Total	197	158	39	80%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	25	1	96%
Jackup	9	7	2	77%
Semisub	34	33	1	97%
Tenders	2	2	0	100%
Total	71	67	4	94%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	51	49	2	96%
Semisub	46	43	3	93%
Tenders	N/A	N/A	N/A	N/A
Total	98	92	6	93%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	109	93	16	85%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	113	96	17	84%

Sub-Saharan Africa

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

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	7	3	4	42%
Jackup	25	20	5	80%
Semisub	14	11	3	78%
Tenders	N/A	N/A	N/A	N/A
Total	46	34	12	73%

Source: InfieldRigs

17 February 2015

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

When automation, not if

Automation on the drillfloor has been slow to take off – but it is coming as advances in enabling technologies are made. Elaine Maslin looks at work ongoing in the field.

Automation on the drillfloor has been slow to take off – but it's coming and there will be no going back, according to many.

According to the Gartner "Hype Cycle" curve, drilling automation has been in a trough of disillusionment, says Geoff Downton, a founder member of the SPE's drilling systems automation technical sections (DSATS), from Schlumberger. But, it is now on its way out of the trough, and, there's no going back. "It's not a case of 'if automation,'" he told the SPE Drilling Automation seminar held in Aberdeen late 2014.

But, drilling automation doesn't necessarily mean automating the full system, and it will require advances in enabling technologies, such as downhole communication links and open architecture, says John Macpherson, Chairman of DSATS and a senior technical advisor for Baker Hughes. "Across industry there is much better understanding of automation and that we are not going to automate everything in one go," he says.

DSATS was set up in 2008 to accelerate the development and implementation of systems automation in the well drilling industry. Its definition of drilling systems automation includes, importantly, everything that's in real time, from the drill bit to shore, including monitoring, advising, controlling and autonomous systems.

Currently, autonomous systems have been developed for down hole – because they need to be. The surface is automated to a certain extent, with the driller remaining in the loop. Onshore teams are then able to monitor, but not control operations.

Subsurface communication complexities

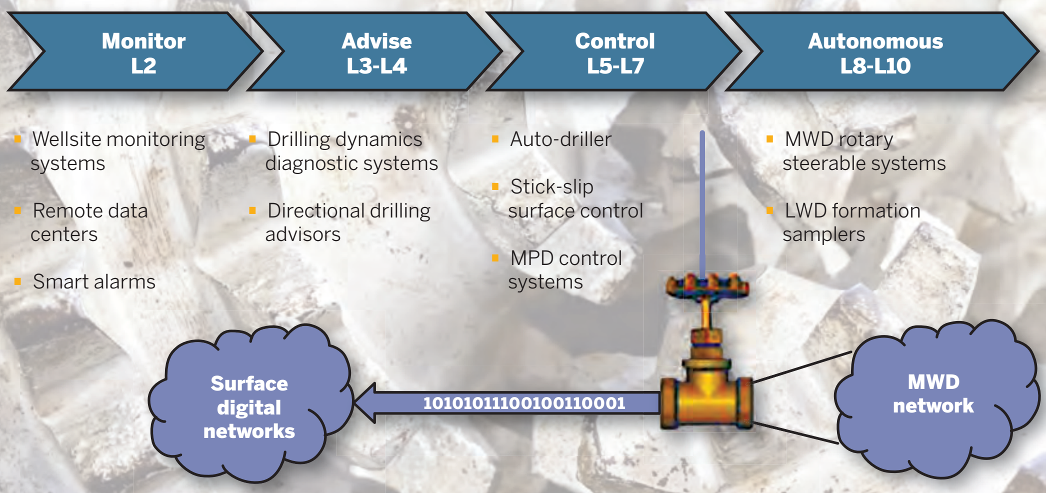
A key challenge for automation is understanding the complexities of the subsurface, in real-time, which, combined with low data uplink rates, means grafting on an automated downhole mechanical system into the drilling process which is not as simple as it might sound.

"There is a lot of devil in the detail and when you start putting automated systems together you find things that are not as you would like in existing systems," says Macpherson. "Downhole, we can make measurements in the string, of the borehole wall, even ahead and around the drill bit. You get some idea of what's happening and there's even actuation in terms of the steering systems we have. But really that's the challenge, trying to control this process."

"We have a downhole tool, which has its own control systems. It measures some tool response, it's influenced by what it's drilling through and it's influenced by drilling parameters from the surface. The tool can steer, it has measurements, but it may not be necessarily where you want it to be, and the uplink is slow, and the downlink really slow. Trying to [maintain] control with these delays, coupled with human intervention, makes control from a process perspective very interesting. From an automated control perspective, this is a particularly challenging problem that has to be addressed."

One of the bottlenecks is the communication between downhole and topside, with uplinks, in the best cases, at about 40 bits per second at the moment. But, such bottlenecks are being addressed. Wired pipe could offer an answer to the downhole

The current level of automation in drilling



Images from DSATS. Both images first appeared in SPE paper 166263.

data issues, under the right economics, providing an alternative to mud pulse telemetry, Macpherson says.

Standardization

DSATS is working to address some of the challenges in drilling automation – and allow smaller companies, or even companies outside the oil industry, to provide solutions – by opening up the communications systems and infrastructure "so everyone can play."

It has promoted a communications protocol (OPC-UA), which is being adopted by the industry. The protocol describes how data moves between different objects, allowing a third party to safely plug in and provide applications to optimize the system.

DSATS is now working on a rig information model to allow a third party to know what it is looking at when it plugs into a rig system. This would include environmental information and hardware limits, in order for the third party to control the rig equipment.

Once refined, the rig information model will be handed as a recommendation to a third party, such as Energistics, who will build it into recommended guidelines for drilling systems automation, and perhaps eventually into a standard. Energistics is responsible for WITSML, a web-based version of the Wellsite Information Transfer Specification (WITS) a common communication protocol.

A further piece of work is a security and threats model for connectivity, being created jointly between the SPE and International Association of Drilling Contractors (IADC).

A further challenge is controls modeling, Macpherson says. While the capability exists to model complex systems, from the bit up to the surface, modeling from a controls perspective is a challenge due to the many elements that influence system behavior, which may or may not be known, Macpherson says.

First, there is a requirement for high quality, reliable real-time data, then an understanding of measurement delays ,which wired drill-pipe would help with, and then there is a need for real-time modeling itself. "Our perspective on modeling has to change to a control point of view, a real-time point of view. So real-time control – what measurements you make, how you close the loop, how you model the system in real time - this is probably a little beyond us at the moment, but this area is beginning to evolve and we certainly have the computer power to do it."

DSA road map

To illustrate the possible development pathway of drilling systems, a Drilling Systems Automation (DSA) Road Map initiative has been put together under the affiliation of SPE, IADC and AUVSI.

The task has been split into eight groups: Systems architecture; Communications; Instrumentation and measurement; Drilling machines; Control systems; Simulation and modeling systems; Human factors; and Certification and Industry Standards.

Each of these groups is taking the individual subject areas and mapping how the technology is likely to develop and then bring it all together to see, as a whole, how they perceive it going. This information would then be shared so that anyone with business in this area can appreciate what direction the technology is going.

The idea is that the DSA road map can also identify technology gaps, which companies might decide to pursue.

Inevitable automation

Automation on the drillfloor has been slow to take off – but it is coming as advances in enabling technologies, such as downhole communication links, as well as creating open architecture, are made.

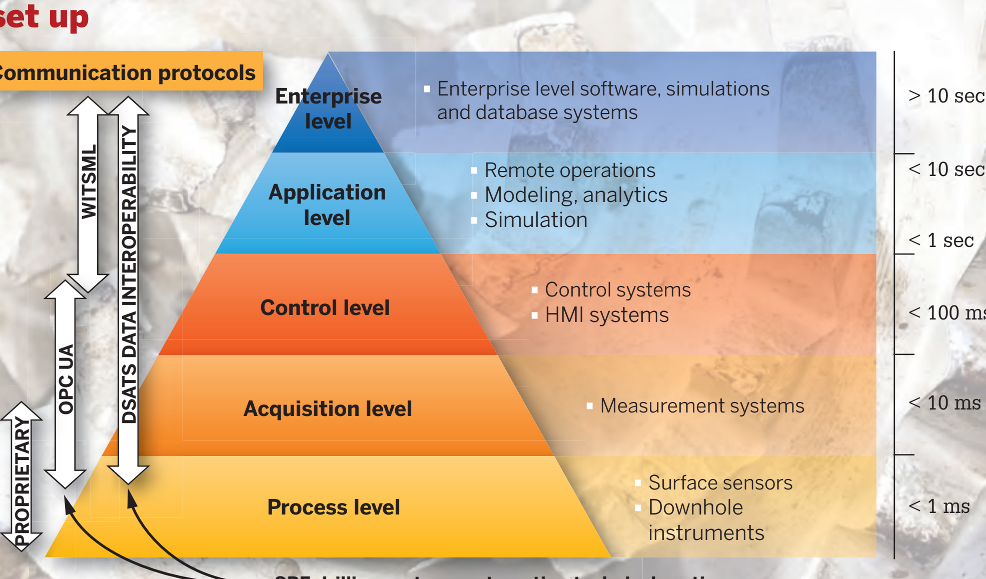
For Odd Erik Gundersen, associate professor, Department of Computer and Information Science at the Norwegian University of Science and Technology, increasing automation in the drilling process is "inevitable," and has the potential to achieve consistent higher quality and safety. "To me it's a no-brainer," he told the SPE seminar.

But, he says automation will not solve everything, particularly when it comes to situational awareness or handling unexpected events. He suggests a hybrid solution where computers can make the main bulk of decisions that are non-exceptional and do not require human creativity as part of the problem solving process, while the human is still involved in the complex decisions.

"The business model is evolving and is certainly disruptive and transformative. You know automation is going to leave this industry changed, but what the change is and how it takes place is a story that is evolving," Macpherson says. OE

FURTHER READING For more information on DSATS go to: http://connect.spe.org/DSATS/

The DSATS set up



Learning IE lessons learned

Is the oil industry good at lessons learned but not at learning lessons? – asks Jan-Erik Nordtvedt, SPE Intelligent Energy program committee chair 2014 and President and CEO, Epsis

Almost a year has passed since the SPE Intelligent Energy 2014 conference. A key discussion topic during the event was why the deployment of Intelligent Energy (IE) is taking so long. Why wasn't IE more broadly and deeply embedded in the oil companies and in the service sector? Particularly, at that time, when the oil price had been stable at around US$100/bbl for a number of years.

One would have expected that the improvement potential from IE would have made attractive business cases across the industry. Still, many of the delegates commented on the slow uptake of loosely integrated solutions. Since then, the oil price has halved. It is natural to ask if there is more or less need for IE in this environment and if one should expect more or less active IE programs in a low oil-price/lower cost environment.

There are many facets of this complex question, but I would like to focus on one – *efficiency*. Many claim that the amount of engineering work needed to produce a barrel of oil has sky-rocketed over the past decade. For example, an up to 50% increase has been reported on the Norwegian Continental Shelf (NCS). People point to compliance, technical requirements, and competency as possible reasons why this is happening.

Investment in IE

The NCS has made substantial investment in IE initiates; with many reports of significant value being realized – particularly within improved operations. Most companies have put in place video conferencing, real-time data collection, data sharing and collaborative facilities. Over the last decade, bandwidth to Norwegian offshore installations has followed Moore's law of exponential growth. This has allowed for video conferencing, data sharing, and the replication of high resolution real-time data to onshore.

In many ways, we have increased the complexity of the onshore and offshore working day – we can analyze, assess and discuss much more than before. This holds the promise of understanding the root-cause of any operational problem faster and in a better way – surely one of the pillars of IE. One should expect that this would also result in the opportunity to produce more oil with the same number of people, and thus, give an increased efficiency. But, the opposite is being experienced.

A simple, yet important, reason for this could be that the added complexity is introducing new inefficiencies, e.g. the technology is not integrating easily with the other components of the business. Video conferencing gives us the ability to put a face to a voice, real-time data to understand the dynamics of the reservoirs, and collaborative facilities the opportunity to improve decision-making.

Joining up the dots

However, if we're not able to align people to the same goals, get consistent execution of process (between people and crews) or link business processes to day-to-day operating procedures, the technology implemented will not give all the improvements it promises. In short, if you're not willing to change the way you work, don't expect ground-breaking results from IE solutions either.

In Norway, and probably in other oil and gas provinces, we have – in the good times – simply added more engineers to resolve a problem, because, in prosperous times, no one asks about how to save an hour or two per engineer each week; how to align the various goals, make technology stick or help to adhere to processes is not on top of the agenda. There is less focus on running more effective meetings, having standardized processes, providing situational awareness data to immerse staff in or to save time during handover. We could just use another engineer if we're not able to complete what needs done. Now, in more challenging times, we have to use fewer engineers. The result is that less work gets done.

This is not new. That we are in an industry that gets a "kick" out of technology is well known, after all this is an engineering-heavy industry. That we're not overly enthusiastic towards process adherence and knowledge-sharing is not new either. This has been on the "lessons learned" flipcharts of most organizations for years.

It seems like we're pretty good at lessons learned, but less so at learning lessons. In our current environment we will need to be. We may even find that it is hugely rewarding. Changing the way we work – ensuring process adherence and people's buy-in – will, in my mind, be a big step forward within IE. Not that we need a low cost environment to do so, but maybe it can provide the right incentive.

SPE Intelligent Energy 2016 will run 6-8 September 2016 at AECC, Aberdeen.

Jan-Erik Nordtvedt is president and chief executive officer (CEO) at Epsis and was SPE Intelligent Energy program committee chair 2014. He holds a PhD degree in physics from the University of Bergen in Norway. Nordtvedt started his career with Statoil in Norway, and has since worked more than 25 years within the oil and gas industry. Epsis assists clients in implementing and getting value from deploying integrated-operations workflows using collaboration-management software.

Transforming the future of oil

Repsol's Director for Exploration and Production Technology Santiago Quesada discusses the company's partnership with IBM aimed at developing cognitive technologies for better decision-making.

As demand for oil and gas increases and oil plays mature, operators are faced with the challenge of having to look deeper and further offshore. In the face of increasing uncertainty and geological risk, oil and gas companies are turning to advanced cognitive computing technology to aid in their search of new oilfields.

Until recently, geoscientists have been tasked with mostly manually reading and extracting information from enormous amounts of data retrieved from their exploration and production activities, including journal papers and baseline reports as well as seismic imaging data and reservoir models, wells and facilities.

Recognizing the need for an intelligent solution that could drive improvements in exploration and production, Repsol and IBM, building on their existing collaboration, recently teamed up to develop cognitive technologies that can analyze subsurface data on geology and crude reserves and, ultimately, help oil and gas companies to make better informed decisions based on that data. As a result, these companies will be able to maximize access to better exploration areas, increase the productivity of maturing oil fields and their value and mitigate environmental risks.

Based at IBM's Cognitive Environments Laboratory (CEL) in New York, the researchers will work on two prototype applications which are specifically designed to increase Repsol's strategic decision-making process in the optimization of oil reservoir production and in the acquisition of new exploration areas and production fields, both onshore and offshore. The first application will help Repsol to size up exploration blocks and the second will support the company in optimizing its strategy for the development of fields.

Repsol is making an initial investment of US$15 million to $20 million in order to develop both applications with early results expected for late 2015. The team will work together in New York and Repsol's Technology Centre in Madrid, with each company committing six to 10 employees to develop the technology.

The cognitive computing technology infrastructure has been designed specifically to extract all the relevant information from complex databases and interact with people across various devices and physical spaces. For example, the technology can process questions asked by humans in natural language and sifts through information to respond with the most likely answers. This, in turn, enables individuals and teams to make better decisions by overcoming cognitive limitations posed by big data.

In addition to spoken word, scientists in the CEL will also experiment with a combination of traditional and new interfaces which are based upon gestures, robotics and advanced visualization and navigation techniques. Using these techniques, researchers can leverage sophisticated models of human characteristics, preferences and biases that may be present in the decision-making process. The technology will also introduce new real-time factors which should be considered such as current news events around economic instability, political unrest and natural disasters.

These tools are not intended to replace the human elements and activity that takes place in oil and gas exploration and production, but to assist them in building more fluid conceptual and geological models, highlighting the impact of potential risks and uncertainty, visualizing trade-offs and exploring what-if scenarios.

The new applications developed by Repsol and IBM will improve the way oil companies visualize and develop exploration and production activities, enabling them to look for oil deeper and further offshore and in more remote areas. In addition, it is envisioned that companies from other sectors will set up their own CELs to make better informed decisions and stay ahead of the curve. OE

***Santiago Quesada** serves as director of exploration and production technology at the Repsol Technology Centre. He oversees centers in Madrid, Houston and Rio de Janeiro. Quesada joined Repsol in 1998 as a specialist in basin and petroleum system analysis in Madrid. Thereafter, he worked for the company in Argentina as exploration manager before returning to Spain in 2008 as manager of quality assurance of exploration projects. He was appointed technical director of exploration geology in 2012 before assuming his current position in 2013. Quesada received his Master of Science in geology from the University of the Basque Country.*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Acquiring geotechnical data for platform foundation design in Mexico's Bay of Campeche
Image from Fugro.

What lies beneath

Most of the Mexican side of the Gulf of Mexico remains unexplored. Dan McConnell explores the geotechnical knowns and unknowns in the basin.

With the historic energy reform transforming Mexico's petroleum sector, what will oil companies and service providers need to know about working in Mexico?

Fugro has been a major supplier of offshore survey and geotechnical services to PEMEX since 1983, providing positioning, geotechnical engineering, integrated geophysical studies, data collection of ocean currents, site characterization, risk modeling, and earthquake engineering.

Working closely with Mexican oil field services provider Grupo Diavaz, Fugro has produced more than 1500 geotechnical investigations and geophysical surveys both in shallow and deep water offshore Mexico.

Bay of Campeche

Much of the early work consisted of understanding the site conditions and soils in the Cantarell field, one of the world's offshore "supergiant" oil fields, located in the shallow waters of the Bay of Campeche.

Oil and gas fields in these waters have been under intense development for over 35 years. New operators entering production sharing contracts in these developed areas as a result of the energy sector reforms will need to understand where the existing man-made infrastructure is. Dense developments in these areas require the use of dynamically positioned vessels, instead of anchored work barges, in order to avoid interference. An


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SAFER
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accurate record of surveyed infrastructure is essential before launching any operations.

In contrast with the US shelf areas, where operators need to be concerned with highly mobile soils and punch-through hazards from shallow sands, the Bay of Campeche soils are calcareous. Foundation designs that are successful in the northern Gulf of Mexico are not adequate for calcareous sediments, in which the bearing capacity of piled foundations can be significantly weaker.

Shell's Perdido platform in the Gulf of Mexico in 2010. Photo from Shell.

Indeed, not only are the soils generally weaker, but in certain layers they are also prone to cementation along certain discrete formations where there is more sand content.

Knowing the distribution of these subsurface layers and the juxtaposition of geotechnical properties is critical for site specific foundation design. The main derivations, pile drivability and end-bearing capacity under vertical and lateral loads, are critical installation and design parameters that are calculated from laboratory analysis of geotechnical samples. Anomalous zones of weakness, such as buried reefs, are also common and must be identified and avoided when designing foundations for structures.

Other conditions affecting foundation design are slope stability, currents and scour, and seismic response, although slope stability is generally not a concern in most of the flat Bay of Campeche; nor is the area, with a few exceptions, prone to soil scour. The response of the structures to ground motions caused by earthquakes, however, is a critical factor for foundation design. Structures also need to be designed to accommodate lateral loads from tropical storms and hurricanes. Storms crossing the Bay of Campeche are less frequent than those that affect oil field structures in the northern Gulf of Mexico, but they still occur and have to be factored into designs.

Pervasive shallow gas has to be carefully mapped and monitored when planning the installation of structures. Out-of-date surveys will not suffice since enhanced oil recovery (EOR) effects need to be anticipated.

New deepwater developments in the Mexican Ridges

Mexico's first deepwater development will be the Lakach gas field, in 1000m water depth, about 100km off the Port of Veracruz. Here the geologic setting approaches the Mexican Ridges. Although surveys have been carried out in support of the specific development, there are still many unknowns with respect to ground conditions.

Calcareous soils transition to siliciclastics in the Mexican Ridges area, with different angles of repose and slope failure triggers and response. The Mexican Ridges is a compressional, seismically active area, especially just off Veracruz. This seismic activity necessitates fuller understanding of ground movement and slope instability, among other issues. Age dating slope failures and measuring potential run-out of submarine landslides are essential requirements for planning developments in this area.

The Perdido

PEMEX's ultra-deepwater discoveries to date are in the Perdido Fold Belt, a trend that starts on the US Gulf of Mexico and becomes more fully developed on the Mexican side. The Perdido is expected to hold world class reserves. On the US side the discoveries and developments by Shell were some of the most technically challenging for a number of reasons, not only that the discoveries are in water depths of 3000m. It was the need for long term investment and specialized technology to develop these deepwater fields that was part of the drive for energy reform in Mexico.

The geotechnical and geophysical challenges here are similar to those in the US side of the Perdido trend. Gas hydrates were found in the Frio sands at the crest of Chevron's Tiger Shark exploratory well which, with the right geometries and depths, can present gas hazards*. Operators looking south along the Perdido should expect similar challenges including reactive clays, borehole stability, and overpressured flowing sands in the top sections of the wells.

Much is still to be explored

Although early satellite work to look for natural oil seeps indicates strong possibilities for completely new hydrocarbon plays, most of the Mexican side of the Gulf of Mexico remains unexplored. Will there be analogs to the new discoveries in the US Eastern Gulf of Mexico, or new hydrocarbon plays in the Campeche Knolls regions? Energy reform will accelerate the answers. What is certain is that the Gulf of Mexico is the world's premier deepwater hydrocarbon province and that new hydrocarbon plays will be found on both sides of the border.

Fugro's primary operational office in Mexico is in the port complex in Ciudad del Carmen and administrative offices are in Mexico City. **OE**

*Subsurface gas hydrates in the northern Gulf of Mexico, Marine and Petroleum Geology 34 2012 - Boswell et al

__Dan McConnell__ is Director of Business Delivery, Fugro. A marine geologist, McConnell has written numerous articles about deepwater site conditions, frontier marine geochemical surveys, and gas hydrates. McConnell holds degrees in Latin American History and Geology from the University of Texas at Austin.

RED gets ready

Resonance enhanced drilling could help speed up drilling time and efficiency. Elaine Maslin reports.

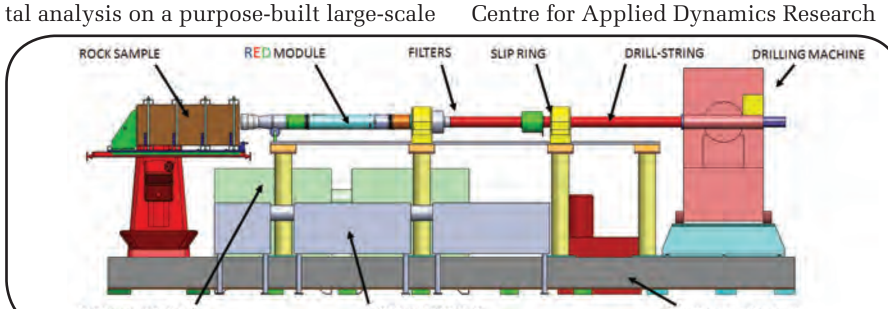
After nearly two decades research, work looking at how high-frequency impacts effect the dynamic fracturing of rocks, in a way which could significantly boost drilling efficiency, is close to completing its latest trials – with the hope the next step will be field trials.

Resonance Enhanced Drilling (RED) has been developed at the University of Aberdeen-based on research by applied dynamics Professor Marian Wiercigroch, based on theoretical mechanics.

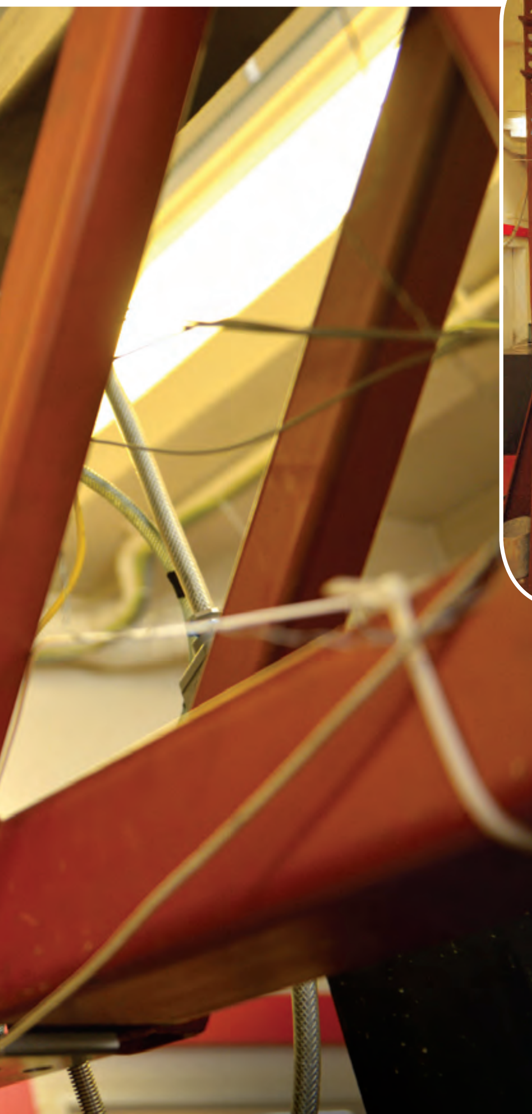
The technique, which uses high frequency, to create resonances and to generate a controllable zone at the bit, improving significantly rate of penetration and reducing bit wear, as well as stress on the bit, has its roots in theoretical dynamics and fracture mechanics. Wiercigroch has been keen to prove and calibrate the theories through experimental analysis on a purpose-built large-scale test rigs (see the photograph and schematic of the vertical and horizontal RED experimental rigs).

The result, he says, is a flexible technique, able to be optimized according to rock type, which could improve on average drilling rates by at least 40%. In case of hard rock drilling, the improvement can be as large as 250%.

"There is nothing similar out there," says Wiercigroch, who is director of the Centre for Applied Dynamics Research



A schematic of the horizontal RED full scale experimental rig (the total length is circa 8m and the rig allows for comprehensive testing programs with a large flow rates of drilling fluids).



Professor Marian Wiercigroch with the vertical RED full scale experimental rig.
Images from the University of Aberdeen.

within the University of Aberdeen's School of Engineering. "It is excellent for hard rocks and could reduce the cost of drilling significantly which is so important in the current situation."

Classic drilling technology uses axial static force (weight on bit) and rotation, to shear off layers of the formation being drilled. RED adds high frequency oscillatory loading to the rotary drill bit. In other words, with RED controllable high-frequency axial vibration is added, creating resonance conditions which dynamically fracture the rock. The frequency, typically around 150-800Hz depending on the application, with 1mm maximum amplitude, is created using a transducer, and can be adjusted according to the drilled formation.

To protect instrumentation behind the drill bit, transducer and exciter unit, a vibration isolation unit has been

The vertical RED full scale experimental rig (the height is around 4m and the rock sample is turned instead of drill-string).

included in the assembly, and has proved effective, Wiercigroch says.

Early small-scale experimental studies were launched in about 2000, using the piezoelectric transducer, with results indicating a large improvement in penetration rates, a steadily propagating crack zone, and good borehole stability. In 2006, drilling tests were carried out on basalt, pink granite and sand stone, with drilling rates improved by 20X compared to conventional drilling techniques, Wiercigroch says.

To further understand and refine the results, more theoretical studies were performed, and then bifurcation analysis, confirming the mathematical models. This meant the model could be refined to operate at "sweet spots," – the best frequencies and amplitudes.

The work also looked at how different porosity and permeability rocks would impact the stress and strain values. A joint study with Brunel University has also looked at fracture processes at the borehole.

Testing has been performed on a suite of gradually larger and larger test rigs, including a 3.4m-high rig, culminating in the full-scale, horizontal test-rig, which the university is using today, using industry-standard polycrystalline diamond compact (PDC) and roller-cone drill bits. Both rigs work by rotating the sample, rather than the rig and the most recent experiments have shown drilling time rate improvements of a factor of four and five.

Finally, the mathematics have been simplified to enable faster predictions, which means the drilling can be controlled downhole in real time, Wiercigroch says. This does mean that the current technology for communication down hole to topside, when the unit is controlled downhole, is sufficient [See "DSATS" story on page 24]. Work is also ongoing to develop the drilling head to optimize pressure pulse signals to the surface to 50 pulses per second.

"With this technology you would not have to change the drill-bit so many times because the static weight is less," he says. "This means less non-productive time. Drilling could be few times faster – and the borehole stability could be better. You can drill with less force on the formation because the force required to break the rock is obtained from a dynamic contribution. This means you can redesign the drill-string so it doesn't have to be as heavy and you can drill much more easily horizontal wells." The dynamic stress is also propagated in the direction of the drill bit, not perpendicular to it, maintaining good borehole stability.

RED is not designed for soft formations, but, as it uses classical drag type drill-bits, this can be accommodated for, says Wiercigroch, by turning off the RED module. The key is to determine and maintain the resonance in the borehole for varying conditions through monitoring feedback responses.

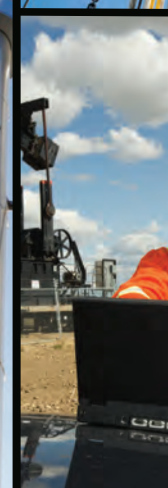
The RED research program has come a long way since it first started in 1998, with funding from the Centre for Petroleum and Marine Technology, and has since had backing from the Royal Society, Royal Academy of Engineering and the Engineering and Physical Sciences Research Council as well as from industry including BP, BG Group, NOV, QinetiQ and others.

This year a 60-month, £4.6 million research and development program funded by ITI Energy, focused on upscaling the RED technology and bringing it closer to the commercial world (now part of Scottish Enterprise), will be completed. The program has been a team effort involving in total six academics, 12 research fellows six PhD students and two technicians.

"We are close to the stage where the RED technology can be tested by industry and I hope this will happen soon," says Wiercigroch. He adds: "RED has a diverse range of application and as well as use in oil and gas drillinghe the technology can be used in geothermal drilling, as well as in mining and even in dentistry." OE







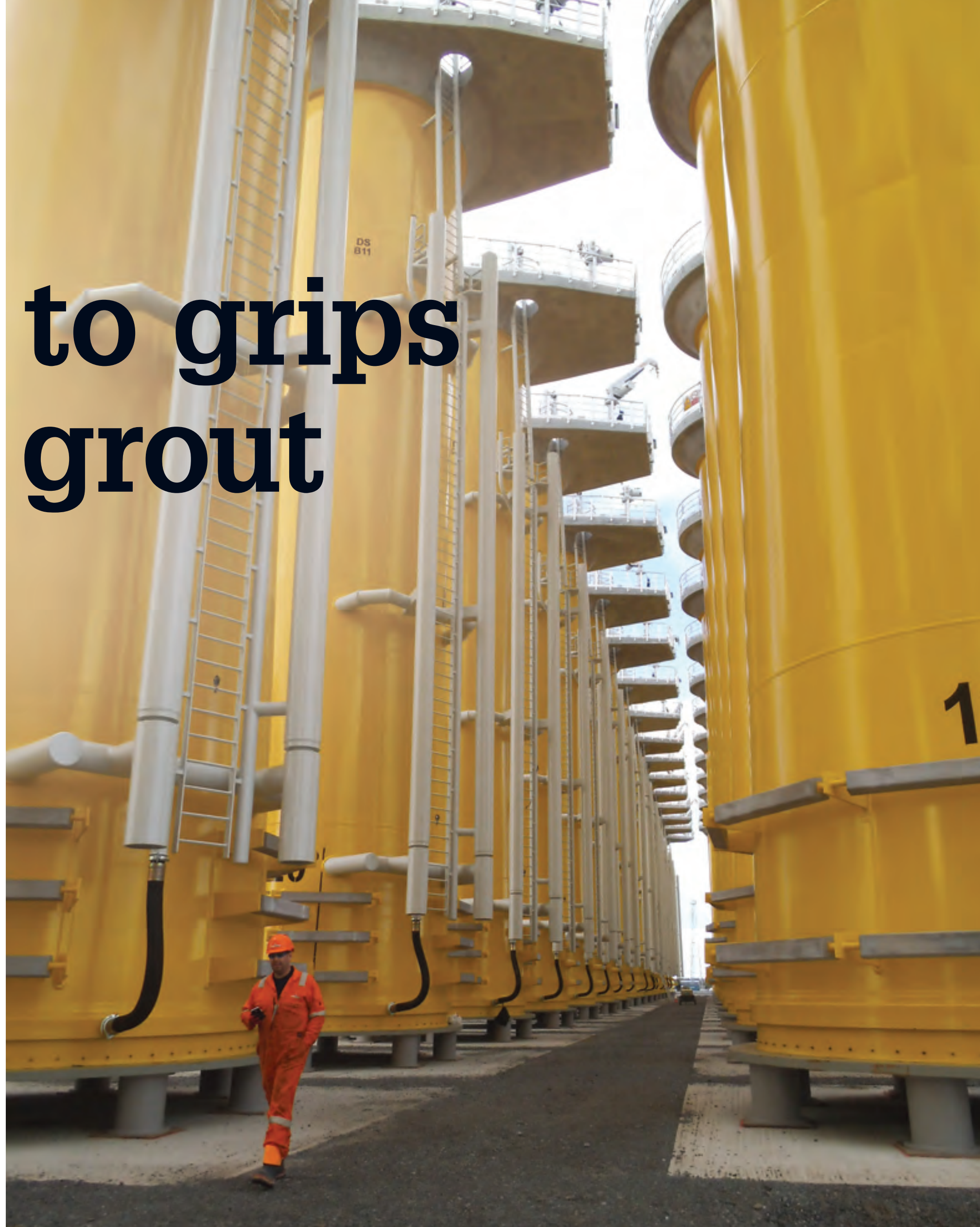







Getting to grips with grout

Grout is taking on new forms to meet the needs of offshore wind applications, Jim Bell explains.



FoundOcean worked on the 30 wind turbine Ormonde Offshore Wind Farm, 10km off Barrow-In-Furness in the Irish Sea. The farm used jacket foundations similar to those used for oil and gas platforms. Ormonde was the first large-scale commercial wind farm in European waters to use jackets for the turbine foundations as well as the substation foundations. Photos from FoundOcean.

Grout is fundamental for offshore structures, for member filling to strengthen and repair jackets; fabric formworks to support and stabilize pipelines and grouted clamps to repair damaged pipelines or jackets.

Although only contributing to a small proportion of a project's costs, in the case of foundation installation, grout is an essential component which contributes to the structural integrity of the foundation and therefore its long-term capacity to generate revenue. As such, it is essential to choose the best material for the job.

Grouts for offshore use come in a number of different strengths; standard, high and ultra-high. However, strength is not the only material property that needs to be considered; durability and volume stability also need to figure highly. The potential for improving project productivity rates and safety, both on and offshore, linked to the mixing and pumping, delivery and resupply, and storage of the material are also very important.

The supporting foundation structures for offshore wind turbines are typically either monopiles with transition pieces, in shallow water depths up to 35m, or four-legged jacket structures for deeper waters. The loads acting on both types of structures would be similar and would involve the following; wind loading, wave loads, current, boat impact and fatigue loads (low stress, high cycle wave loads).

As monopiles are stand-alone single structures, the monopile/transition piece grouted connection is subjected to very different loading conditions when compared to the pile sleeve grouted connections of jacket structures. The monopile/transition piece grout will be subjected to compression and tensile loading, in addition to bending and torsion. Pile sleeve grouted connections however will be subjected to simpler loading consisting of compression and tensile forces.

For these reasons, high strength grouts are required for monopile/transition piece connections, in order to resist the extreme loading conditions that apply. In a typical monopile/transition piece connection, with a monopile of 5.8m upper diameter and 7.8m lower diameter, the grouted connection would require approximately 20.0cu m of high strength grout, such as MasterFlow 9500.

For pile sleeve grouted connections where OPC is typically used, a single connection may require up to 8.0cu m of ordinary Portland cement (OPC) grout.

Oil and gas

Foundation design for greenfield oil and gas structures very rarely demand ultra-strong bonds; ordinary Portland cement (OPC) is therefore most often used, providing a connection that is more than adequate. OPC is suitable for projects specifying strengths of between 40 and 70MPa; for example, in main leg or skirt pile grouting of platforms or in the filling FoundOcean's fabric formworks. This tried and tested practice of offshore grouting with OPC is carried out by FoundOcean using its recirculating jet mixer (RJM), which achieves mixing rates of up to 30cu m/hr.

Offshore wind

Ultra-high strength grouts, on the other

FoundOcean's RJM (recirculating jet mixer).

The West of Duddon Sands offshore wind farm saw 108 turbines installed.

hand, have numerous applications in situations that require 28-day characteristic strengths of 100MPa or higher. These types of grout are synonymous with monopile transition pieces for offshore wind foundations. Ultra-high strength grouts are occasionally used in life extension projects where they are used to replace OPC in member strengthening projects and in grouted repair clamps.

Ultra-high strength grouts have enhanced properties over OPC, which have been engineered into the product to allow for the dynamic loads and choice of foundation. For grouted connections in offshore wind, FoundOcean primarily uses BASF MasterFlow 9500, for which it is a licensed applicator. MasterFlow 9500, in addition to ultra-high strength, offers a number of pioneering properties, including;

- Zero autogenous shrinkage, a factor that has been shown to cause cracking in high strength concrete structures and de-bonding within connections, provides high volume stability
- Rapid strength build up to support increased installation rates and to guarantee stable structures at an early age reducing the risks from cyclic loading.
- Low heat of hydration, eliminating the risk of thermal cracking.

Significant cost savings can be achieved with the availability of materials, such as MasterFlow 9500, which can provide adequate curing rates at low temperatures. The faster a material cures, the shorter the weather window required to complete the grouting operations. Even at low temperatures, MasterFlow 9500 develops significant strength early on and as such can be applied at lower temperatures compared to similar products. This makes it suitable for use in colder periods and means it can make use of shorter, and more frequent, weather windows. As a result, there is less chance of a project being delayed due to adverse temperatures frequently experienced in the spring and autumn months. This means vessel productivity can be increased and installation times kept to a minimum. Thanks to its impressive properties, MasterFlow 9500 is the first product of its kind to receive the latest DNV GL certification for offshore concrete structures.

However, ultra-high strength materials do not easily lend themselves to the high delivery rates of ordinary Portland cement. Materials that can consistently provide strengths above 70MPa include additives and aggregates which, due to their non-homogenous structure, must be batch mixed to ensure the correct blend of all the components is achieved. Consequently, these materials are stored in bulk bags, which must be batch loaded into the pans for mixing, unlike the RJM's, which have the advantage of being a closed and autonomous system. Moreover, the bags must be transported in 20ft containers, rather than 100-tonne silos, taking up more valuable deck space.

FoundOcean has developed the super pan mixer, designed to help eliminate grouting as a potential bottleneck when mixing and pumping ultra-high strength grouts offshore. The super pan mixer was the first to enable batch mixed materials, including ultra-high strength grouts, to be mixed and pumped at rates exceeding 10cu m/hr. At the DONG Energy/ ScottishPower Renewables West of Duddon Sands Offshore Wind project, in the Irish Sea, this resulted in a time saving of two hours per foundation. For projects the size of West of Duddon Sands (108 turbines) this kind of saving can amount to considerable savings in the vessel's critical path over the duration of the project.

However, the real challenge has been to develop a material that, although a blend of more than one component, delivers a consistent mix that can be used with a pressurized silo and RJM mixer.

Ongoing development

FoundOcean collaborated with chemicals company BASF to develop the BASF MasterFlow 9800, which launched in February. The material has been specifically developed to meet the demands of the offshore wind industry, where improvements in productivity and efficiency are key for the long term sustainability of the industry.

This new material offers the advantage of being significantly faster, as well as cleaner and safer, than its predecessors. Since the material is able to be used in silos, vessel resupply is more efficient. Moreover, the FoundOcean RJM may be used to provide mixing and pumping rates close to 20cu m/hr. As previously mentioned, RJM spreads are enclosed systems, which essentially eliminates the escape of cement dust into the environment. Moreover, RJMs require minimal support to carry out the grouting operations, compared to the labor intensive pan mixers. In essence, the material is set to revolutionize the client's choice and expectations with regards to delivery and resupply of grouting materials. **OE**

Jim Bell *began his engineering career in heavy civil engineering and highway construction at Wimpey Construction Group. He then moved to the offshore division of Wimpey Laboratories. Bell took the role of Managing Director at FoundOcean in 2005, where he has implemented major strategic changes resulting in a significant expansion of the business. Bell holds a degree in civil engineering from London's City University.*

Seafloor tools

Susan Gourvenec outlines toolbox approach for optimizing geotechnical design of subsea foundations

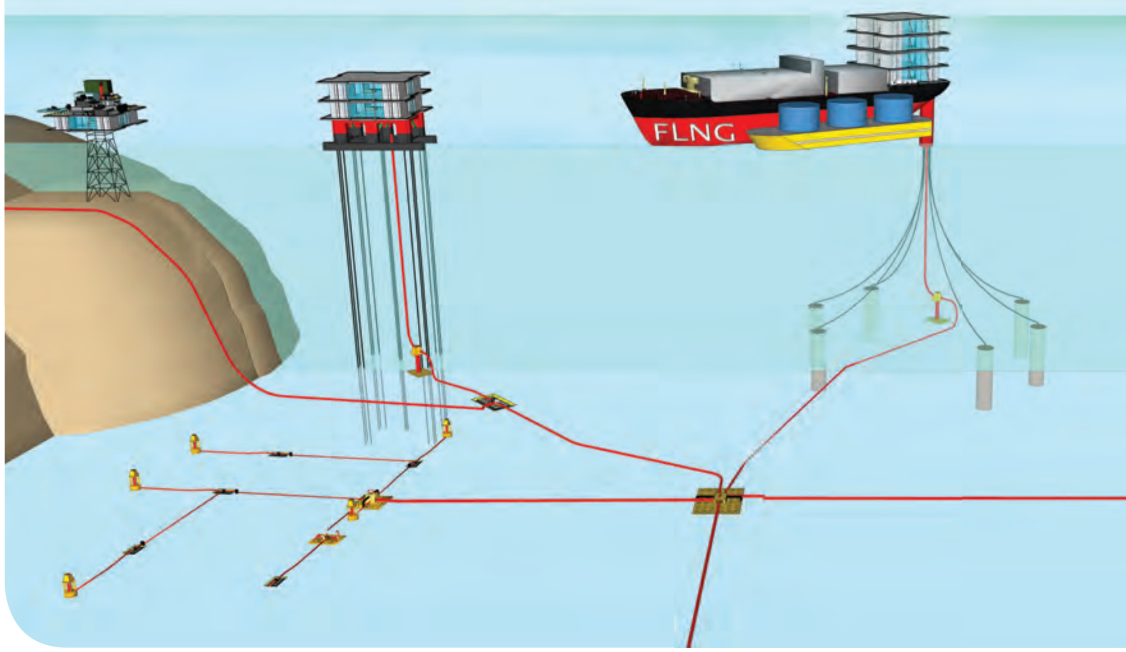


Fig. 1: Evolution of offshore architecture. Image created by M Cocjin, COFS, UWA.

Subsea foundations are becoming increasingly widespread as offshore development moves away from the conventional template of a fixed platform over a set of wells to subsea development of multiple wells and fields tied back to a single facility.

Subsea developments comprise a network of infield flowlines and assorted pipeline and wellhead infrastructure, which is typically supported on shallow, mat foundations – or "mudmats."

The geotechnical design challenge of subsea mudmats is to withstand greater dead and operational loads on softer seabeds without increasing the footprint size or weight. The motivation is to reduce costs associated with installation – for example eliminating the need for a heavy-lift vessel to place the mudmats alone if handling limits of pipe-laying vessels are exceeded – whilst providing acceptable in-service reliability.

There is a toolbox of solutions for optimizing the geotechnical design of subsea foundations, to reduce the size of mudmat foundations for the same operational conditions, compared with designs based on conventional practice. Such methods may improve the viability of projects, contributing to the unlocking of valuable but currently 'stranded' hydrocarbon reserves.

Optimization of capacity assessment methodology

Classical bearing capacity theory is recommended by most industry guidelines and is typically used to design subsea mudmats, but has been shown to poorly represent the actual response for a range of offshore foundation and loading conditions.

The alternative "failure envelope approach" allows ultimate limit states to be defined in terms of individual load components and explicit definition of the boundary conditions, such as foundation geometry and soil strength characteristics. The result is a failure envelope or surface defining ultimate limit states in combined load space, such that the effect on factor of safety of a variation in any independent component of load can be assessed.

A new failure envelope framework has been developed to predict undrained ultimate limit states of subsea mudmats under loading in six degrees of freedom (1). The industry partner involved in the project reported that the new design methodology has led to the possibility of reducing the size of shallow foundations such as pipeline end termination mudmats by 20%, or alternatively are able to withstand larger jumper loads.

Optimization of foundation configuration

Hybrid subsea foundations A hybrid subsea foundation involves a mudmat and a deeper foundation system acting in consort to increase load carrying capacity above the mat alone ultimately leading to smaller required footprint sizes. Two concepts for hybrid subsea foundations have been considered at the Centre for Offshore Foundation Studies (COFS), one involving corner pin-piles as the deeper foundation solution and another using mid-line suction caissons.

Considering the pin-pile hybrid foundation, in practice the mat would be laid on the seabed and the piles then jacked through a tapered slot in the mudmat, with a locking cap to restrain the pile head from vertical displacement while allowing pile rotation. Centrifuge modeling has been carried out at COFS to assess the viability and potential gains in capacity of the pin-pile subsea foundation. A simplified lower-bound approach has been developed for predicting capacity of pin-pile subsea foundations whereby the mat carries the entire vertical design load and the pile group carries the entire sliding and torsional loading. Even considering the two foundation systems independently, i.e. not relying on interaction between the mat and the piles, indicates considerable increase in capacity can be achieved over the mat alone (Figure 2).

Research on pin-piled hybrid subsea foundations has continued at COFS looking at fully combined load response in six degrees of freedom and at the load-sharing of the mat and pile group when acting

in consort. The design framework developed at COFS shows that provision of pin-piles can reduce footprint areas by up to 60% for typical deepwater field conditions. The industry partner on this project has adopted this innovative pin-pile hybrid foundation system on Esso's Erha North project offshore Nigeria as a cost-effective mitigation solution against pipeline walking.

Internal shear keys Provision of sufficient internal shear keys or "skirts" to prevent shearing within the confined soil plug of a skirted foundation enhances mudmat capacity. Results from a program of finite element analyses have been distilled into simple design charts defining the optimal number of internal shear keys as a function of equivalent embedment ratio for intervals of strength heterogeneity index and vertical load mobilization (Figure 3). It is seen that the commonly adopted shear key interval of s/d = 5 in engineering practice over-estimates the critical number of internal skirts for cases of low vertical load mobilization, low soil heterogeneity index and low embedment ratio but becomes unconservative with increasing vertical load mobilization, soil heterogeneity index and foundation embedment ratio. The recommendation of s/d = 18, is shown to over-predict the required number of skirts for all conditions.

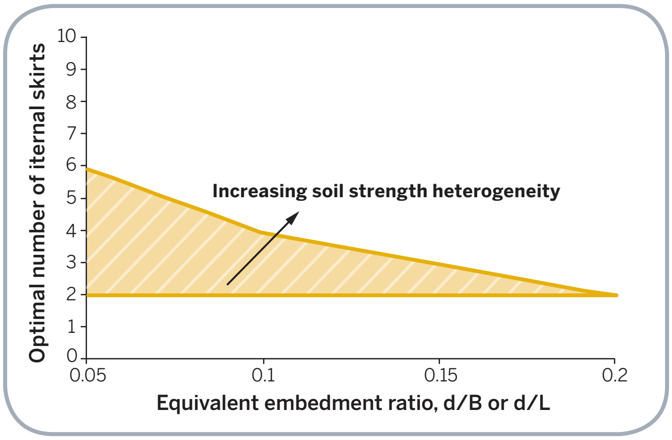


Fig. 2: Load carrying benefits of a pin-piled hybrid subsea foundation. Image from COFS.

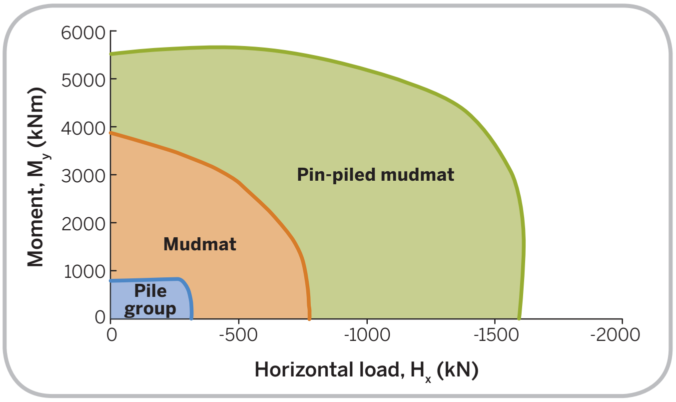


Fig. 3: Optimal number of internal shear keys for subsea foundation under 6 dof loading. Image from COFS.

Optimization of geotechnical input

Best available site investigation data
A sound understanding of near-surface soil strength is essential for the accurate prediction of the response of structures laid on or shallowly embedded in the seabed, such as subsea mudmats (and pipelines). A number of novel tools suited to near-surface strength characterization are being developed at COFS, including the hemi-ball and toroid and the pile penetrometer.

Consolidated undrained strength In an offshore scenario, a mudmat and supported structure may be set down on the seabed several months in advance of operation of the attached pipelines, when the horizontal loads (and therefore moments and torsion) come in to play due to thermal expansion of the attached pipelines. Consolidation of the soil in the vicinity of the foundation will take place under the self-weight of the foundation and structure it is supporting in the period following set down and before operation.

Further efficiencies in subsea foundation design can therefore be realized if the consolidation-induced strength gains can be banked, i.e. it may be possible to rely on a higher value of undrained shear strength than measured in situ. The time lapse between installation and operation may range from a few months to a year depending on the project, over which time considerable gains in shear strength may be achieved, depending on the consolidation properties of the sediment.

A theoretical method for predicting consolidated strength gains in capacity of shallow foundations under vertical preloading, based on a critical state framework has been developed at COFS. The theoretical method has been applied to a range of foundation and pipeline problems under multi-directional loading, providing a quick and easy method for predicting consolidated undrained resistances.

Effect of cyclic loading All offshore structures and hence the foundations that support those structures are subject to cyclic loading. Cyclic loading of subsea foundations may arise from environmental, installation or operational loading. Unnecessary conservatism in parameter selection is required to account for uncertainty in the effect of cyclic loading on engineering parameters, which will lead to conservatism in design output. Current work at COFS is investigating a framework to predict cyclic degradation of soil properties, with particular attention to subsea mudmats. Foundation capacity could then be assessed by accounting for consolidated gains in capacity, modified by a reduction factor to account for cyclic loading degradation.

Optimization of operational mode

Challenging the traditional but conservative paradigm that a foundation should remain stationary, optimization can be achieved through tolerable foundation mobility.

The concept of mobile foundations is that they are designed to move tolerably across the seabed to absorb some of the load imposed by thermal expansion of the pipeline rather than being designed large enough to resist all the operational loads and remain stationary. The concept of mobile foundations is radical, but a logical progression from the now widely-accepted practice of permitting subsea pipelines to buckle laterally either across the seabed or on engineered structures in response to thermally-induced expansion during operation (*OE*: April 2014).

Conclusion

A tool box of solutions to optimize the geotechnical aspects of subsea foundation design has been highlighted. The various options can be described by an 'optimization class' in terms of (1) optimizing the design methodology, (2) optimizing the configuration of the foundation, (3) optimizing the geotechnical input parameters and (4) optimizing the mode of operation. The techniques described are examples of some tools in each class, but the implication is not that the tool box is complete. Much scope exists for adding new tools in each class. Current research at the Centre for Offshore Foundation Systems at the University of Western Australia is investigating new tools for predicting cyclic load response and settlements – tools that are simple enough to use but sophisticated enough to capture the necessary aspects of soil behavior. Many of the technologies described in this paper have been applied in practice supporting projects offshore Australia and globally. **OE**

This article is based on a longer paper *Frontiers in Deepwater Geotechnics: Optimizing Geotechnical Design of Subsea Foundations* by Susan Gourvenec and Xiaowei Feng, published in a special edition of Australian Geomechanics, December issue, 49(4).

***Susan Gourvenec** is a Professor at the Centre for Offshore Foundation Systems at the University of Western Australia. Gourvenec has more than 15 years of geotechnical engineering experience, with particular interest in offshore geotechnics. She is a consultant offshore geotechnical engineer to industry and member of the ISO and API Committees for Offshore Geotechnics.*

FURTHER **READING**

Mobilizing subsea foundations. http://www.oedigital.com/energy/renewables/item/5474-mobilizing-subsea-foundations

AIM for life – and beyond

Floating production systems are on the hard edge of asset integrity management, says Jonathan Boutrot.

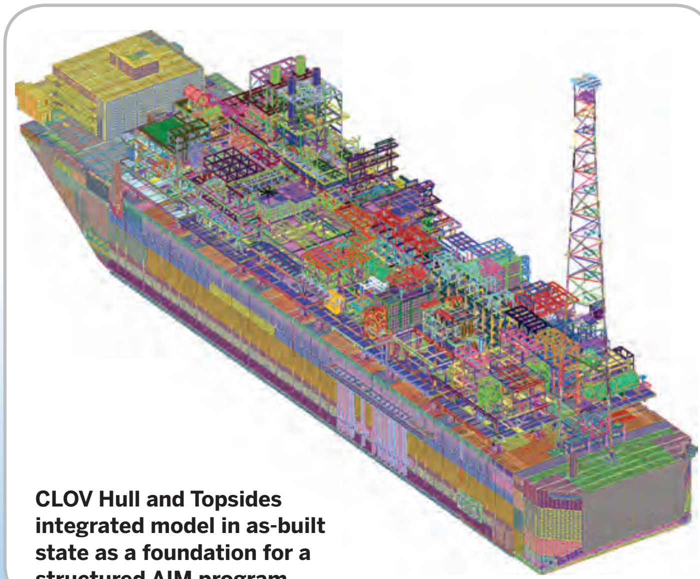
The business case for having an asset integrity management (AIM) system in place for offshore assets is getting more and more cogent every day.

There has always been a need to protect assets systematically and oil majors often have in-house asset integrity systems for their shore-based assets. But a conflux of pressures is making a formal, tailored and maritime-specific AIM system a must for both fixed and floating offshore assets.

The low and falling oil price is hitting capital expenditure, which means operators can build in less resilience to new projects and conversions. That means more care is needed during the life and operation of the asset. Regulatory pressure is increasing and public expectations are much higher, especially post-*Deepwater Horizon*. Operators of offshore assets need to be able to prove they have and are looking after assets safely.

And then there is life expectancy. This is where the big bulge in demand for AIM systems come. Many offshore assets, especially floating production, storage and offloading vessels (FPSOs), are reaching the end of their design lives. In the current market, there is little appetite to replace these with new units, but there is still oil and gas to recover. So the demand is there to squeeze a longer life out of ageing assets.

The design life of many FPSOs built since 1980 was 20 or 25 years.



CLOV Hull and Topsides integrated model in as-built state as a foundation for a structured AIM program.

Total's CLOV FPSO is the second project where Bureau Veritas has integrated certification of the topsides, risers and subsea installation with classification of the hull of the floater and one of the several floating assets where an AIM system was developed during the build phase. Images from Bureau Veritas.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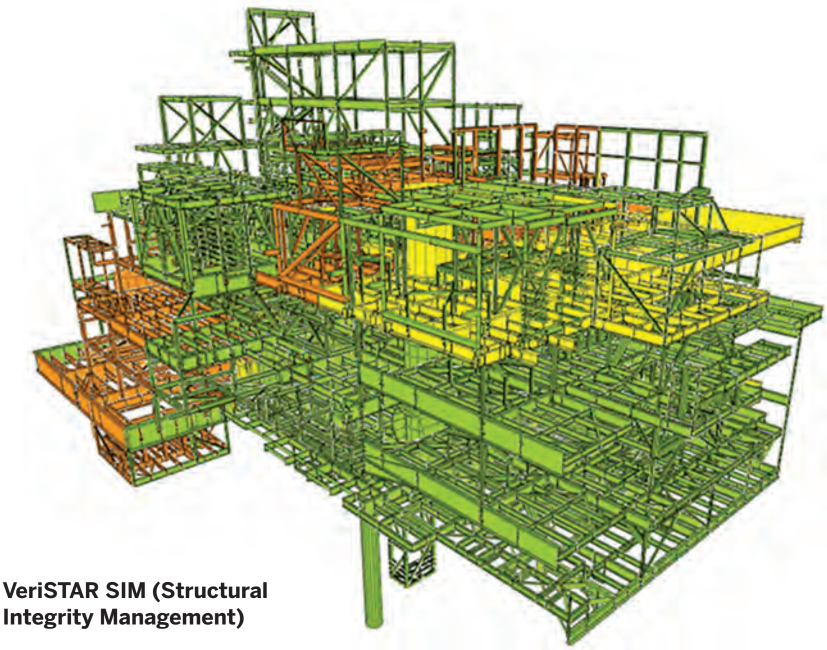
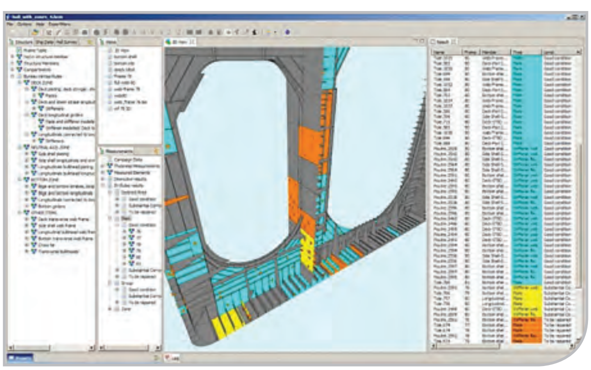


VeriSTAR SIM (Structural Integrity Management)



VeriSTAR Hull Life Cycle screen shot showing 3D visualizer.

Feedback in service has shown that in some circumstances the design life was over-optimistic. As the industry moved quickly further and further offshore from the 1980s onwards, FPSO design did not always keep up. Some units have proven inefficient and difficult to maintain.

Life extension

Today, as a bulge in the age profile of these offshore assets reaches and passes its design life, operators face a key question: is my asset suitable for life extension?

To make correct engineering and economic judgments on the life extension of FPSOs, operators need to know the full history of the unit. They need to have a clear picture of its current structure and condition and a prognosis of how that will develop in the future. Most importantly, they need in place a system that will monitor the asset during its life extension and ensure that the structure is behaving as expected.

The system required is a modern asset integrity maintenance system (AIMS), which encompasses a structural integrity maintenance system (SIMS). That means a planned and systematic way of building the data required to understand the condition of the structure and having in place an inspection and modeling system to keep that up to date.

It sounds simple, but in practice, because there are many contractual and other parties involved, a full AIMS and SIMS built up from the as-built condition is rare.

CLOV

For FPSOs being built today, operators can benefit from experience and begin to integrate a comprehensive AIMS process from the design phase, involving all parties. An example of that is Total's CLOV, where Bureau Veritas integrated certification of the topsides, risers and subsea installation with classification of the hull of the floater and developed an AIM system during the build phase. When Total faces life extension issues in 25 years' time, they will have the information they need to make sound decisions.

Tecnitas, BV's advisory arm, was given responsibility for structural integrity management of the FPSO. This meant compiling a complete record of the construction detailing all nonconformities and preparing a full finite element model of the hull and topsides in as-is condition on delivery to Total. The model is the platform for of an ongoing risk-based inspection (RBI) program and an AIM scheme provide by Bureau Veritas. It will use VeriSTAR HLC software for tasks including inspection of relevant structural areas, assessing the corrosion condition of the FPSO against BV or user-defined criteria, and managing the data on the structure and topsides over the long term in an open format.

A big part of any modern AIM system is risk assessment. As we gain experience with offshore floaters in harsh deepwater environments we build better knowledge of offshore floating units and how they degrade over time. Feedback of their structural behavior over a long period of time allows us to improve the risk assessment. That makes for more cost-effective inspection and more targeted maintenance.

We are seeing an increasing demand for RBI plans as these improve because of the increase in built-in feedback. These are based on a semi-qualitative approach, with the analysis built on discussions with several experts (HAZID) who understand how the asset is operated, what the condition of the structure is, what the coating is like and what could be the consequences of a structural failure.

Classification society rules

AIM improvements built on RBI also have consequences for classification society rules. Class uses a prescriptive rule approach to define the tank inspection schedule, typically annual survey, intermediate survey every 2.5 years and class renewal survey every five years. This is being replaced by an RBI approach defining the inspection schedule. BV is now doing this for an oil major-operated FPSO off Angola.

RBI applicable parameters must include coating degradation, corrosion, fabrication quality control, fatigue and crack propagation, and well-thought through risk characterization, which measures each risk in terms of safety, the environment and the business impact.

BV is developing a qualitative RBI plan, including HAZID, to define a tank inspection schedule for one of the giant Nigerian FPSOs. In addition the oil major will use the VeriSTAR AIMS database including data management and inspection schedule and the VeriSTAR HLC (hull life-cycle) geometrical model for corrosion assessment and inspection management. RBI plans are also being developed for a complete field of fixed platforms in Asia.

AIMS and SIMS track ageing. Aging is not a matter of how old the equipment is, it is a function of what you know about its condition, and how that is changing over time. Indicators of ageing are many. There are frequent or recurring defects and failures, an increasing incidence of unplanned maintenance, repairs and breakdowns and signs of degradation. The plant may be down-rated or it may require increasing inspection and testing frequency to manage degradation.

The difficulty for operators, especially of older units, is that these indicators do not present themselves in a uniform or coherent manner, and the consequences of these indicators may fall into the different areas of responsibility of different areas of the company or project. The data about the indicators may be available, but it may not always be available to the people who can make sense of it or who need it to plan how to avoid an incident or downtime.

The tools and systems available to enable operators to know the condition of their asset structure and to monitor and predict how that condition is changing over time are what we call AIM and SIM systems.

More than an engineering tool

The most important single thing about AIMS and SIMS is that they are not simply engineering tools for engineers. They are a cluster of software tools, inspection techniques, data management and data sharing platforms and good organizational practices. Each part alone provides only part of the solution, and to be effective all parts have to be embraced by the management of all the parties involved.

That is the difficult part of implementing an AIMS and SIMS process. There is a tendency to look for black box technical solutions. Good technical solutions such as 3D modeling and finite element modeling analysis are vital, but these tools only produce good answers if used by people willing to seek out and collate the right input information and the good answers only produce a better and longer-lived structure if they are understood and acted upon by the operators.

What new technology can do for AIMS is save time, improve traceability and reduce errors and omissions by reducing the human input. For example, the thickness measurements are today done manually by a surveyor who writes down values on a sheet of paper and then back in office populates the thickness values on a geometrical model or in an Excel table. Bureau Veritas is now testing new methods by using ROVs for the thickness measurements, linked with computers which automatically update a geometrical model.

The challenge for AIMs providers is to further develop the tools so they are coupled through each phase of the AIM system, open to connection at any stage with company and operator in-house systems and work in the same way for each area of the unit. That has to be done in the face of a cost squeeze and in a race against time as assets pass their design life. OE

Jonathan Boutrot is Offshore Development Manager at Bureau Veritas.

Leap of faith

Will subsea tech join fracking slowdown? There may be too much momentum. Bruce Nichols reports.

Subsea oil and gas processing technology takes a big step forward this year when Statoil starts up gas compression systems at Åsgard and Gullfaks, shifting this major component of offshore production from the platform to the seafloor for the first time.

But with oil prices down more than 50% since mid-2014, there is concern further technological advances could slow as leaner cash flows and shrunken capital spending heighten operators' already conservative approach to risk.

There are reasons for optimism. Deepwater projects are different from onshore shale projects. Onshore shale has a short timeline and already is feeling the effects of lower prices. Deepwater projects are long term, take years to unfold and will be slower to react.

There are so many projects already sanctioned and underway in the Gulf of Mexico, off Brazil and West Africa, that analysts see momentum carrying development forward into a time when oil prices likely will be higher.

"Because of sunk capital, the point-forward breakeven oil prices for these projects is lower, meaning that 2015 and 2016 prices will have short-lived impacts on the commercialization of these fields and will be offset over time as oil price recovers," says Wood Mackenzie analyst Jackson Sandeen.

Douglas-Westwood also expects a short-lived oil price downturn. The energy research firm sees subsea CAPEX exceeding US$30 billion in 2015, dipping a bit over the next three years, but rising again in 2019 past $35 billion, Houston director Mike Haney told a recent energy industry luncheon.

"Our view is that the oil supply will need to be there, and producers have less spare capacity (than in past downturns)," Haney said.

Even if oil prices don't return to the loftiest levels, further development of subsea processing – compression, power delivery, pumping and separation – could improve deepwater economics by boosting recovery, lowering per barrel lifting cost and easing the need for expensive offshore platforms.

Testing for Train 2 of the Asgard subsea compression system was completed in December at Aker Solutions' dockside yard in Egersund, Norway. It was then moved to a disassembly area for transportation to the offshore installation site.
Photo from Aker Solutions/ Rolf Estensen.

Compression projects advance

In the area of compression, optimism is high that the Aker-MAN dry-gas compression system at Åsgard and the OneSubsea multiphase wet gas compression system at Gullfaks will succeed. Statoil expects the systems to increase ultimate recovery at Åsgard by 280 MMboe and at Gullfaks by 22 MMboe.

"There's no reason why it won't work, but we're all waiting for it to start up," said Global Technology Director Phil Cooper of INTECSEA.

The Åsgard system, sitting in 1050ft of water, 125mi off Trondheim, is big. It has two 11.5 megawatt (MW) compressors in a football field-size, 5000-tonne frame that contains separators and two 736-kilowatt (kw) condensate pumps. It will be powered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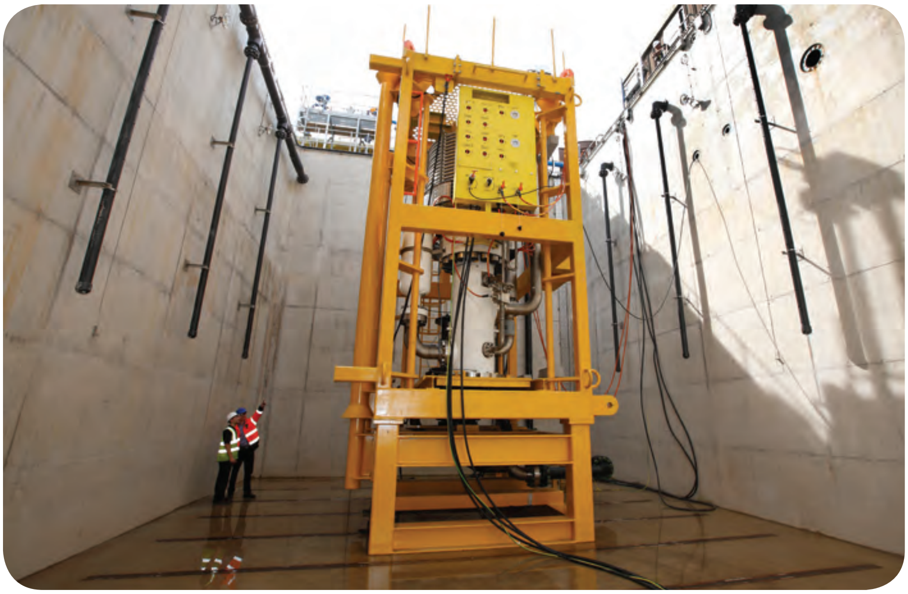


FMC Technologies has teamed with Sulzer to compete in subsea boosting. Their new 3.2-mw, 5000-psi helico-axial Sulzer pump, driven by an FMC Technologies permanent magnet motor, is shown in Sulzer's Leeds, England, test facility. Photo from FMC Technologies.

through 25mi of subsea cable from the Asgard B platform. Current cost estimate: $2.3 billion.

"Aker Solutions will deliver advanced subsea processing solutions this year through the Åsgard Subsea Compression project. This represents ground breaking technology that brings us closer to placing a fully-functioning production and processing system on the seafloor. The project is to be delivered in 2015 with testing and final preparations already underway. The Åsgard project is an industrial game-changer that has the potential to significantly impact the subsea production market. We expect to further develop the technology to reduce costs by using more standardized tools and optimized module designs," said acting Head of Technology at Aker Solutions, Hervé Valla.

Gullfaks, in 455ft of water, 125mi off Norway northwest of Bergen, is smaller in scale. It has two 5MW multiphase compressors in a structure 112ft-long, 65ft-wide and 45ft-high and weighs 950-tonne. It will be powered by subsea cable from Gullfaks C about 9mi away. Current cost estimate: $385 million.

Unlike Åsgard, Gullfaks doesn't remove liquids from the gas stream prior to compression, so it's simpler. In a sense, Åsgard's system is a compressor built around a separator, and Gullfaks' is a multiphase pump bulked up to do compression.

A third Norwegian compression project, Shell's Ormen Lange, has been canceled, at least for now, due to unfavorable economics. But in design and testing, it took subsea compression a step further.

The Ormen Lange concept had four 12.5MW compressors in 2825ft, powered by 75mi of subsea cable from shore. The Aker-GE built compression pilot system was proven in extensive submerged trials at an onshore facility.

Ormen Lange was to be an important advance in subsea power distribution, an area still in its infancy. For the first time, it would have put a variable speed drive on the sea floor along with a switchgear.

Power transmission, hubs next?

A lot of effort is going into improving power delivery and distribution, developing longer distance transmission capability and seafloor hubs that can distribute power to numerous pieces of equipment. Statoil sees better electrical systems as key to its subsea "factory" concept.

In 2013, Statoil teamed with ABB on a five-year, $100 million project aimed at delivering 100MW through a 375mi cable in water 10,000ft deep. Such a system eventually could be needed in ultra-deep and remote locations, including the Arctic.

Siemens also is running a subsea power qualification program for an ultra-deepwater subsea grid. Other companies, including GE and Schneider Electric, are working on the power challenge.

Issues include that most existing subsea equipment run on alternating current (AC), and there are limits how far AC can be cabled subsea. "You may lose 35% of your power over 100mi," said James Pappas, president of RPSEA, the Research Partnership to Secure Energy for America.

"After 120mi, it becomes obvious that direct current (DC) is the better way to go," Pappas said, "But, we do not have any qualified high-voltage wet-mate connectors for DC."

Others say don't give up on AC power too soon. ABB points to low-frequency AC, used in railways, as offering potential for longer subsea step-outs than standard AC.

Even at 120mi or less, there are a lot of subsea projects within AC reach, so AC systems should be fully developed before shifting major resources to perfecting subsea DC, said Alisdair McDonald, who heads GE's power and processing team.

"I think it (DC) is potentially for the future, but we don't see any business cases today where you'd require that type of system," McDonald said.

Boosting leads the way

The subsea processing technology farthest advanced is boosting. OneSubsea is the leader with more than 20 years experience and 85 units sold for over 30 projects globally. OneSubsea absorbed subsea pump pioneer Framo Engineering when the organization was formed in 2013 by Schlumberger and Cameron.

Subsea multiphase boosting began in 1993 with the installation of a system at Shell's Draugen field in 900ft water depth in the Norwegian Sea. A second system was delivered in 2014, featuring two pumps, 2300 kw of power and a design pressure of 3190 pounds per square inch (psi).

ABB delivered this subsea transformer, rated at 19MVA (Megavolt-ampere), for the Åsgard subsea gas compression project offshore of Norway. ABB and others are working to advance subsea power transmission and distribution technology. Photo from ABB.

OneSubsea's latest boosting system, operating at Chevron's Jack-St. Malo project in 7000ft in the Gulf of Mexico, uses a bit more power, 3000 kw, but has four times the shut-in pressure, 13,000 psi.

FMC Technologies, which often teamed with Framo Engineering before it became part of OneSubsea, has now joined Sulzer to challenge OneSubsea's dominance in boosting.

The team is offering a new 3.2MW, 5000psi helico-axial Sulzer pump driven by an FMC Technologies permanent magnet motor. The motor features a fluid gap in the rotor-stator assembly, reducing friction and increasing efficiency.

Progress in oil-gas-water separation

Subsea separation has less of a track record than boosting, but FMC Technologies is the leader, having installed five of the last six major systems, often using pumps now sold under the OneSubsea brand.

The history of subsea separation goes all the way back to 1969 when an early version was installed by BP and Total in 79ft at the Zakum Field in the Arabian Gulf, but the major advances have come since 2000.

In 2001, an oil-water separation built by ABB was installed in 1116ft water depth at Statoil's Troll field. Also in 2001, Petrobras started up a gas-liquid system in 1296ft at Petrobras' Marimba field using a Cameron vertical annular separation and pumping system.

Arguably, the first full-scale system for separating oil, gas and water, with sand-handling capability, was a gravity-based horizontal vessel system built by FMC Technologies and installed in 2007 at Statoil's Tordis field at a depth of 689ft.

The next big advance was Shell's Perdido project at 8000ft in the Gulf of Mexico. Since 2011, it has run a caisson-based system, built by FMC Technologies, using submersible pumps from Baker Hughes. Shell put another FMC Technologies caisson system at Parque das Conchas off Brazil, started up in 2013.

Total installed a vertical gravity-based system built by FMC Technologies at Pazflor in 2625ft offshore Angola. It started operation in 2011 and is notable for vessels 30ft tall and 11.5ft in.-diameter with 4in-thick walls to withstand the pressure.

What some consider the most advanced subsea separation system began operation in 2011 at Petrobras' Marlim project in 2950ft. The horizontal, in-line, cyclonic system built by FMC Technologies avoids the need for big gravity vessels.

"The next frontier is making these systems more compact, more cost-effective and easier to deploy," said FMC Technologies spokesman Patrick Kimball.

The technologies needed are available or within reach, said Ian Ball, director of Subsea Domain, a consultancy. "It's more of an awareness and confidence-boosting that's required," he said.

"We need to find a way to get more operators to qualify and deploy currently proven technologies to boost their bottom-line. Only by doing that will we get the volume of systems manufacturing and installation to bring down unit costs to where subsea processing becomes commonplace," he said.

Jon Arve Svaeren, vice president of subsea processing systems at OneSubsea, agrees. "Used in the appropriate situations and applied correctly, this technology has proven a very effective tool for increasing production and recovery, reducing lifting costs per barrel, and that's important in today's environment of softening oil prices," Svaeren said. OE

Going with the flow

Flow measurement isn't always foremost in industry debates, but the role it plays – and getting it right – is key. Elaine Maslin found out more.

As the oil and gas industry moves into harsher, more complex environments, so too do metering technologies and the requirements on them.

Building, testing and calibrating wet gas and multiphase meters, creating meters for high-viscosity oils, and using data now available through new generation devices for diagnostics and more intelligent calibration regimes, are some key themes for the flow measurement sector.

NEL's 32nd International North Sea Flow Measurement Workshop brought together industry experts to discuss some of these issues and more.

The event, held in Scotland late last year, also saw the launch of the Flow Measurement Institute, which is looking to bring together academia and industry in flow measurement and also be a means to raise the profile in the UK of measurement and the value it brings to the UK.

Phil Mark, director of sales and marketing at NEL, outlined some of the key themes at the event. One is the debate over using substitute versus live fluids when testing or calibrating multiphase or wet gas meters. NEL supports the use of substitute fluids because of the improved uncertainty in calibration calculations, compared with that achievable with live fluids. Making sure that testing and calibration facilities can replicate as closely as possible both operating pressures and temperatures is also high on the agenda, be it for wet gas, multiphase or single phase.

"One of the big drivers for industry and vendors, is trying to find solutions for low cost multiphase flowmeters," Mark says. "At the moment they are very high cost, at several hundred thousand of dollars (each), which potentially limits the number of applications. If a multiphase meter could be made less expensive, whilst delivering the same or similar performance, it would open up a bigger market.

"Other challenges facing the industry include the effect of increasing oil

NEL's new high pressure wet facility near Glasgow. Image from NEL.

NEL's flow measurement facility. Image from NEL.

viscosity on the performance of both single phase and multiphase meters, and the effect of gas entrainment on the performance of ostensibly single phase meters.


Phil Mark

The use of diagnostics parameters, available from the more modern technologies, gives you access to much more than a straight-forward flow signal."

NEL, based near Glasgow, Scotland, is looking at how changes in diagnostic parameters, can be used to monitor the performance of the flow meter, in order to move to condition-based monitoring and calibration, instead of time-based monitoring. The organization, which is the custodian of the UK's National Flow Measurements Standards, is also looking at how the data gathered from such devices can be interpreted in a rigorous and reliable fashion.

Last year, NEL invested in the development of its high pressure wet gas facility, now the UK's only independent commercial test facility that can test meters to flow rates over 2000cu m/hr under wet gas conditions and is capable of using oil and water components simultaneously.

The event also heard from a number of suppliers and operators:

BP

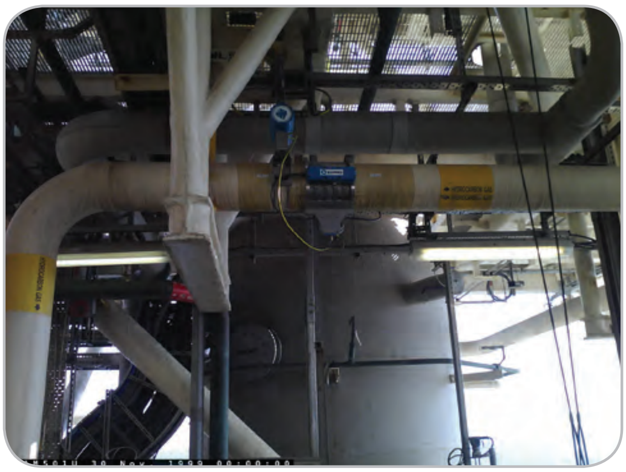
Bill Pearson and Samir Ismayilov, from BP Azerbaijan-Georgia-Turkey – Azerbaijan, presented the development and field trials of SONAR Meter Technology.

The project was a collaboration between BP AGT Region and Expro Meters, part of Expro Group. BP required retrospective, non-intrusive flow measurement in a number of "allocation" metering applications. For two applications, a clamp-on SONAR flow meter was trialled, including field cabling, transmitter, mounting clamp, transducer module, and cover assembly. The ActiveSONAR meter was EX 'd' Zone 1 certified.

The results indicated that clamp-on SONAR technology, as a non-intrusive retrofit meter technology, was at least comparable with other type of technology, such as ultrasound or differential pressure producer meters, and in some cases it was likely to exceed the performance of installed meters.

"As with any type of black box technology, assurance around meter performance is implicit from key parameters or meter diagnostics," the presenters said. "As is current industry practice, with e.g. ultrasonic meter technology, it is possible to benchmark key meter performance parameters during factory calibration / function tests and use these to establish a baseline for performance monitoring / verification in the field."

Pearson also described the prototyping of a SONAR technology meter diagnostic interface from which measurement stakeholders can verify meter performance. In the event that meter performance becomes sub-optimal diagnostics expert support can be sought and, where necessary, the clamp-on meter components can be readily changed under permit to work without the need for shutdown and dependence on isolations for workforce safety.



SD Sonar 10in. Expro flow meter. Images from BP.

The trial sites included a crude oil reception line at the Sangachal Terminal, Azerbaijan, where offshore oil and gas is processed prior to export. ActiveSONAR was also used as a secondary measurement tool to verify an existing legacy ex-test separator gas measurement device as well providing additional measurements during critical well testing operations.

GE

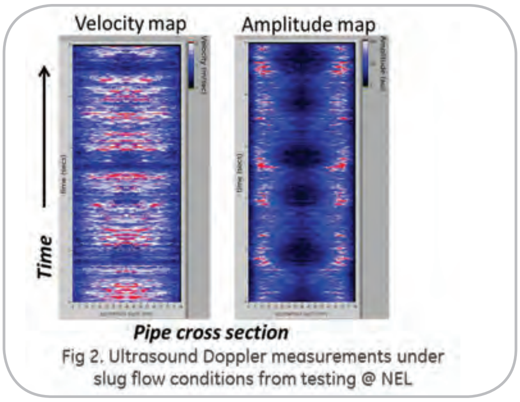
GE's Anusha Rammohan and Baskaran Genesan, GE Global Research – USA, presented their insights into multiphase flow through ultrasound doppler. Multiphase flow could be fully characterized and measured if the velocities and phase fractions of all the components in the flow were available through sensor measurements, they say. For a three-phase flow, for example, this involves measuring six independent parameters. "Since this is an almost impractical expectation, in reality only a subset of these measurements is available to a flow meter," the pair say. "For example, not all component velocities can be directly measured. The burden then falls on the flow meter algorithm to fill in the missing pieces with an appropriate model."

Flow models typically perform well, as long as the flow conditions are within the ranges for which they have been built, but their extrapolative capabilities are questionable making their performance and accuracy unreliable and unpredictable in the field, say Rammophan and Genesan.

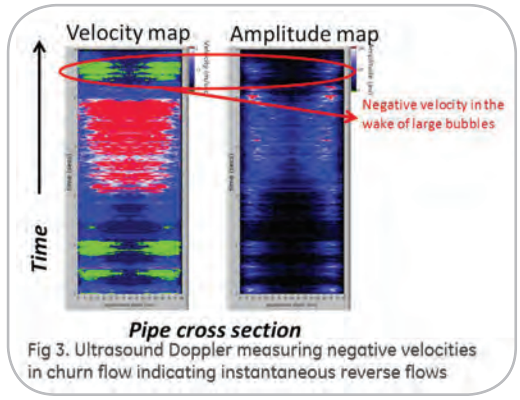
The ultrasound Doppler technique is used to measure velocities based on the scattered signals from small particles or bubbles in the flow. Scatterers could be gas bubbles or oil or water bubbles in the liquid mixture /emulsion.

"The technique works based on the relationship between the measured Doppler shift in the signal frequency and the scatterer velocity," say the presenters. "There is ample evidence in literature on the ultrasound Doppler method being used to measurement velocity in flows with a very small amount of gas (low gas volume fractions). Under such conditions, the flow exhibits a predominantly bubbly flow regime, which is conducive for the Doppler measurement with the small gas bubbles acting as the scatterers."

However, GE has looked at the application of the ultrasound Doppler technique to a much wider range of three phase flow conditions, with varying water cut and gas volume fractions.



Ultrasound Doppler measurements under slug flow conditions from testing at NEL. Image from GE.



Ulstrasound Doppler measuring negative velocities in churn flow indicating instantaneous reverse flows. Image from GE.

"The ability of the ultrasound Doppler technique to measure the velocity and strength of small scatterers in the flow makes it a unique measurement that provides invaluable insights into multiphase flow," say Rammophan and Genesan. "Analysis of the Doppler data, based on an understanding of the flow physics, showed that the scattered signal originating from the small bubbles in the flow contain easily extractable information about the liquid velocity."

The analysis was verified through extensive experimental data collected at NEL and SwRI (Southwest Research Institute), as well as GE's in-house experimental facility, demonstrating that liquid velocity and in turn liquid flow rate can be estimated using the Doppler technique with high accuracy.

"Unlike traditional approaches which use a slip correlation to derive the liquid velocity from other more easily measureable quantities such as the mixture velocity, the Doppler measurement can provide liquid velocity information without the need for complex slip models or any other additional pieces of information," says Rammophan and Genesan.

"This adds to the robustness and reliability in the flow rate measurement. Moreover, the proposed technique also resolves the measured velocity both temporally and spatially thus creating an information rich picture of the flow variations. This information in conjunction with other sensor information can provide critical parameters that can be used as inputs to flow models, thus increasing the overall accuracy of a meter."

Modeling

Uncertainties around modeling was put under the spotlight by Phillip Stockton, from Accord Energy Solutions Ltd – UK. He believes more can be done to calculate uncertainties in simulation factors more robustly.

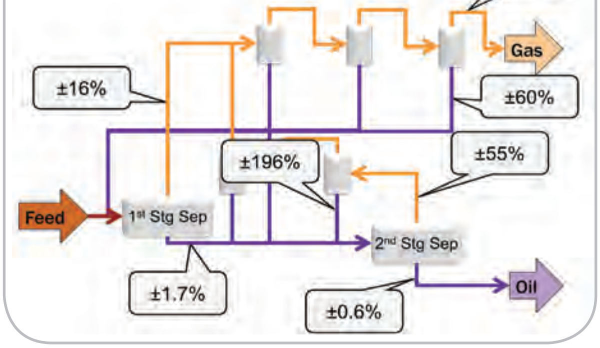
"The main purpose of simulation models within hydrocarbon allocation systems is to provide information regarding how hydrocarbons are behaving in a process plant," he says.

"Allocation algorithms often include factors generated by these models. In calculating the uncertainty in the quantities allocated to each party in an allocation system, the uncertainty in the factors supplied from a simulation has to be accounted for. The uncertainty in the measured quantities is often known with a good degree of confidence but the available data on what the uncertainty of, for example, a shrinkage factor is, is not known and usually arbitrarily assumed to be a value of say ±5%.

"Simulation factor uncertainties can be calculated more rigorously. The uncertainty of a factor generated by a simulation model very much depends on the parameter in question. For example the uncertainty in a shrinkage factor for a dead oil will be lower than that for a lively condensate."

Stockton has been considering the sources of uncertainty within the models and attempts to demystify the black box reputation of these models.

He suggests there are a number of methods that can be used to calculate simulation factor uncertainties, ranging from Monte Carlo methods to more simplistic short-cut methods.



Monte Carlo uncertainties.
Image from Accord.

FORCE

Denmark's FORCE Technology has been building what it says will be the world's largest calibration loop for calibration of natural gas meters.

The new system has been designed using the company's in-house technology, which sees natural gas circulated in a closed loop, Jesper Busk, department manager at FORCE Technology told the NEL event.

FORCE Technology had been using the technology since 2004, and established a prototype system, which circulates up to 10,000cu m/hr natural gas at a pressure of up to 50 bar.

Market demand led the company to design larger facilities. The new system comprises a closed loop, able to work up to 65 bar and a flow of no less than 32,000cu m/hr - and of 41,000cu m/hr at lower pressures.

At the heart of the system is two parallel connected high-pressure blowers, each producing 22,000- 41,000cu m/hr and circulating the gas in the loop at a variable pressure from 3-65 bar. The high-pressure blowers are driven by two 900 kW engines, which makes it possible to calibrate metres with diameters of up to 750mm.

The system provides traceability to the new high pressure calibration system minimizing the calibration inaccuracy to the absolute minimum. It was internationally approved in 2013, and saw FORCE Technology join the European cooperation on Harmonization of The European Natural Gas Cubic Metre (EUREGA). The system was due to be ready for operation by the middle of 2014. OE

Australian and New Zealand offshore exploration

Angus Rodger and Matt Howell discuss the exploration environment as well as the potential impact from the recent fall in oil prices on Australian and New Zealand projects.

Australia has been a core area for many majors for years, but this position has evolved over time. One of the biggest shifts occurred over the last five years, as hundreds of billions of dollars has been spent on LNG development across seven different greenfield projects, and the subsequent lull this has caused in offshore exploration.

Analysis of drilling levels reveals that Australian offshore exploration activity over the 2012-2014 period was significantly lower than that of the preceding seven years. The number of exploration wells off Western Australia halved and drilling in the other sectors, such as Victoria, essentially ceased. Appraisal drilling has been even harder hit, with only minimal drilling activity in the last two years. Conversely, New Zealand had its most active year for exploration and appraisal drilling since 2010, with two rigs in-country. This has had a significant impact on the volume of discovered resource in Australia in each year. Recent annual discovered volumes have been approximately half that of the previous decade, notwithstanding the relatively dismal results in 2008. Exploration offshore New Zealand has also been poor, with only two small discoveries made. Recent drilling by Shell could change this picture, but the results have not yet been released.

Exploration drivers

The key driver for the fall in exploration and appraisal activity is a change in focus from the major oil companies. Development drilling programs for projects including Gorgon, Wheatstone, Balnaves and Coniston-Novara have utilized rigs and capital that may otherwise have been ear-marked for exploration. For example, Apache Energy, which drilled 66 exploration wells in the 2005-2009 period, but only 18 in the 2010-2014 period.

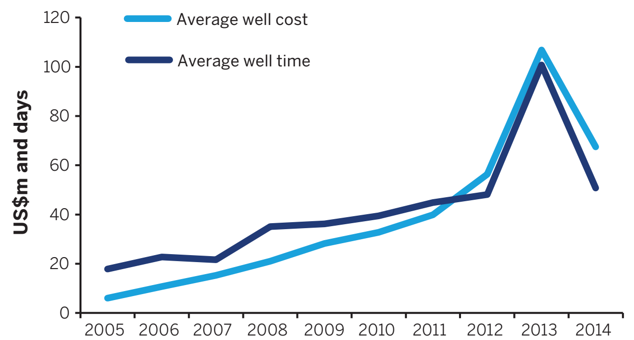
Over the last 10 years, the time taken to drill wells has increased year-on-year. 2013 saw a number of wells take longer than 100 days to drill. While in this dataset (see top chart) it looks to be an outlier, it illustrates the broader trend towards deepwater and more difficult drilling targets and conditions, particularly in the Browse Basin. Longer drilling periods have reduced the opportunity for rigs to drill other wells, contributing to the fall in overall activity.

Drilling costs have also risen dramatically over the last 10 years. Daily rig rates have increased significantly, along with rises in both service company and logistics costs. This has seen companies be more circumspect with their drilling decisions, even in the higher price environment that has until very recently been evident.

New oil price environment

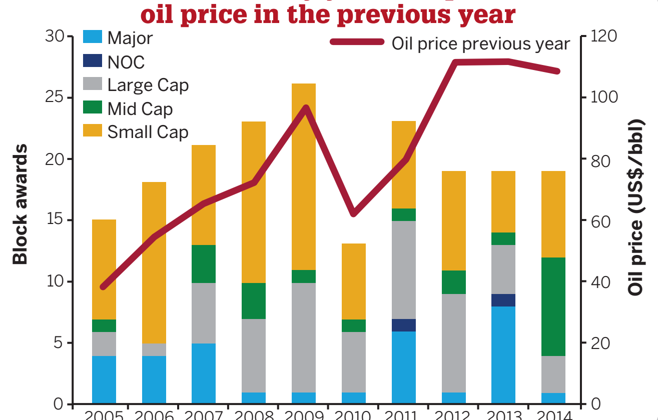
The environment in which oil companies operate changed significantly in late 2014. The low oil price quickly impacted company capital plans, with both development and exploration budgets cut globally. The level of development drilling off

Average well cost and drilling time, offshore Australia (2005-2014)



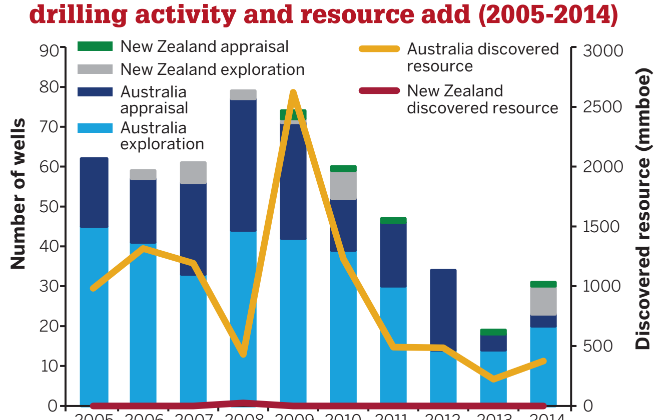
Source: Wood Mackenzie

Block awards by year compared to oil price in the previous year



Source: Wood Mackenzie

Australian and New Zealand E&A drilling activity and resource add (2005-2014)



Source: Wood Mackenzie

Australia is relatively robust and unlikely to see a significant drop off in 2015, as many of the programs are underway already, are needed for contract delivery or are essential for the continued performance of fields that operate with low break-evens and high netbacks.

This could change heading into 2016, if a low oil price persists. The development spend more than 12 months out from early-2015 is likely to be more discretionary and, after a year of low prices, nothing will be sacrosanct. This is where we would expect more of an impact on development drilling and related expenditure.

In comparison, the deferral of short-term exploration activity is a relatively simple way to reduce expenditure and one we are already seeing occur in Australia. Many companies with commitment wells due in 2015 and 2016 are applying to the National Offshore Petroleum Titles Administrator (NOPTA, the government licensing regulator) to defer commitments. If successful, these deferrals could result in minimal exploration and appraisal activity.

In New Zealand, short-term activity is unlikely to be affected by the drop in oil price. One of the two rigs active there is being transported back to Singapore and the other is committed to the continuation of development drilling. The rig is scheduled to remain in New Zealand once that development drilling is complete for an exploration well. That said, this well could be considered in jeopardy, depending on the funding position of the companies involved.

Longer term

We are yet to see if the appetite for new exploration in the longer-term will be affected. An early litmus test could be upcoming license rounds offshore Australia, traditionally a core area of deepwater exploration for the majors. While the plunge in prices may test appetite for blocks that are either in deep water or on the fringes of existing plays, on the other hand acreage can potentially now be acquired through competitive bidding with a far lower work commitment than in previous years.

The low price will have a significant impact on the block bidding level. Analysis reveals there is a very strong correlation between oil price at the timing of bidding and the popularity of rounds and hence the number of permits awarded many months later. This would suggest that bids for 2014 blocks will be healthy, but demand for 2015 permits will decline sharply.

Overall, it is important for companies to maintain a dynamic and evolving exploration portfolio as a driver for future growth. However, in the current oil price environment, companies will be looking for cost savings and exploration budgets are unlikely to be spared the axe. This is despite the bidding process involving companies committing to potential exploration spend in the future, when oil prices have returned to higher levels.

Wells to watch

Nonetheless, there is a number of exciting exploration wells planned during 2015 that will be eagerly watched by the industry due to their play-opening potential. These include Murphy's three-well program offshore Perth basin, and Apache and Woodside's ongoing drilling in both the shallow and deep water areas of the Canning basin.

Like the rest of the world, what is going to happen in Australia and New Zealand over the next 12 months is very uncertain. We predict that explorers will take a more cautious approach to improve near-term returns for shareholders. This will include a reduced focus on frontier exploration, and an increased appetite for short-term and high value opportunities. OE

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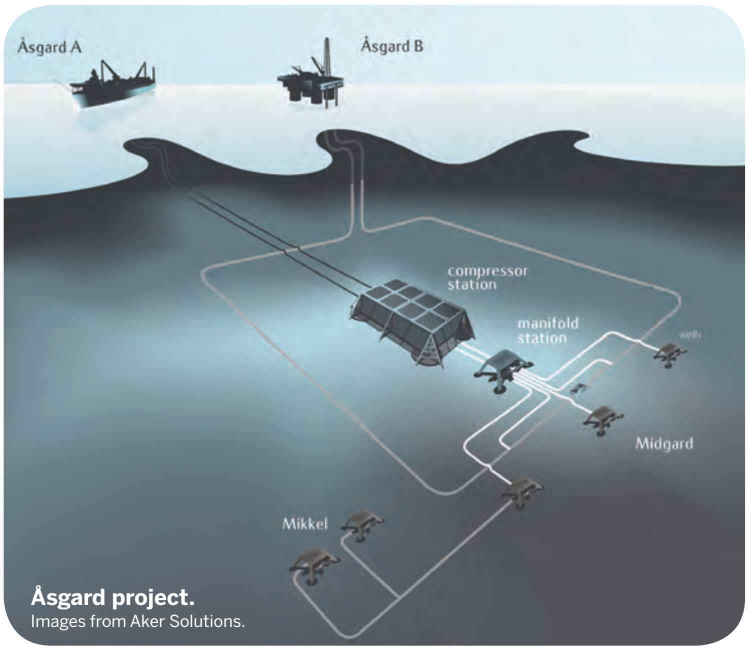
__Angus Rodger__ is Principal Analyst, Upstream Research, Australasia. Rodger joined Wood Mackenzie's South East Asia Upstream research team in May 2008. Rodger holds a BA (Hons) degree in Politics with International Relations from the University of Warwick.

Advancing recovery

Greg Hale takes a look at subsea electronic modules.

"Doom and gloom," and "scaling back" are phrases not heard in the industry in the last five years. But, now there is an opportunity to wring more productivity and profitability out of existing assets.



Åsgard project.
Images from Aker Solutions.

Norway's Åsgard field, about 125mi off the coast, has been producing gas since 2000, but its supply dwindles. Operator Statoil created the first subsea gas-compression facility to boost rates. The facility will become operational this year and Statoil says it should increase recovery by about 278 MMboe and also help keep production running into 2050.

Statoil needed a control system for high availability and reliability. They want to cut down on production stoppages that end up costing big bucks, said Pete Skipp, engineering manager applied technology at Rockwell Automation.

With real estate at a premium, control systems will reside in subsea electronic modules (SEM).

"Most oil and gas producers opt for control systems that have already been proven in topside applications," Skipp said. "We scaled these systems down to Eurocard circuit-board format to fit into existing SEMs. Right-sizing the control system to an existing, subsea-qualified SEM is less expensive and less burdensome than designing, building and testing a completely new SEM. It's also crucial that all electronics used in subsea systems be hardened in every practical sense and thoroughly tested for the environmental challenges they'll face, including extreme temperature fluctuations and severe vibrations."

This architecture provides a small equipment footprint while providing high availability and high integrity (up to safety integrity level (SIL) 3). Subsea systems can also reduce overall operating costs by as much as 50% compared to the costs of building, staffing, operating and supplying a topside platform, Skipp says. Because subsea installations are also unmanned, they offer inherent safety benefits. This presents opportunities to expand production to more inhospitable locations. Subsea production facilities also can recover as much as 20% more from producing fields compared to topside facilities, because less pressure ends up required to pull the product out.

Two SEMs coordinate using secure "black channel" communications links. While performing no direct safety function, the links are purely communications vehicles. The SEMs carry out peer-to-peer communications on these channels, exchanging diagnostic, status and input/output (I/O) information, while also relaying the status of field devices.

If a single device or I/O module fails on one SEM, the presence of multiple data paths ensures continued operation using data from the same device on the second SEM, Skipp says. Subsea operations would only come to a halt if the same two devices failed on both SEMs or if topside communications were lost to both SEMs.

This "hot-swappable" architecture can only occur if the two SEMs are physically separate from each other and provide enough space for a remotely operated underwater vehicle to remove the decommissioned SEM without touching or interfering with the operational SEM.

A subsea control system should use a standard programming environment to ensure easy integration, regardless of which manufacturer's equipment the controls integrate with, Skipp says. The control systems also should have a minimum 25-year lifecycle to support decades of production. The controls should have a demonstrated ability to operate "no touch" for a minimum of five years. Additionally, control systems based on commercial off-the-shelf technology will reduce time spent on customized programming and engineering.

Understanding details

As more sophisticated equipment deploys to the seabed, diagnostics becomes even more vital. Details have to delve deeper than just knowing something is wrong. Diagnostics should provide knowledge of the problem, what it is, and why it happened, so operators can understand the specifics of a failure and build a response plan.

Detailed diagnostics can support overall system management and more accurate troubleshooting. Diagnostics also plays a crucial role in a subsea system's SIL coverage. Basic diagnostics is adequate for SIL 1, but additional comprehensive diagnostics is a must to achieve the more demanding rating of SIL 3. The addition of a second processor to an architecture increases diagnostic coverage and can provide SIL 3 fail-safe coverage.

Using technology can not only boost safety, but keep profit levels increasing during an industry downturn. 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.*

Solutions

Applus RTD exhibits new products

Applus RTD launched its new RTD Plant Master technology, a permanently installed monitoring system, based on ultrasound. It provides continuous wall thickness measurements of critical and hard to access components within refineries, chemical plants, power plants and offshore facilities.

Employing high temperature piezo-ceramics, sensors are applied to ultra-thin foils resulting in flexible ultrasonic transducers which can be permanently dry-coupled directly to the surface of a component. These transducers are then used for single point pulse-echo measurements of the component's wall thickness.

The sensors can continuously operate at temperatures up to 200°C / 390°F, allowing extremely high temperature components to be inspected.

www.applusrtd.com

Outland adds HD 1080P camera

Outland Technology added a new underwater HD Camera to its product line, model UWC-625. The UWC-625 comes standard with an XSK-5-BCL, allowing it to run on all existing Outland cables still out in the field, and can transmits HD 1080P over standard Outland coax cable.

At 2.375 in. in diameter and 5 in. in length, the unit has a depth rating of 500m with an optional 2000m available. With uses ranging from ROVs, diver handheld, fixed installations and more, the UWC-625 provides HD 1080P resolution for live video and recording. Housing materials includes acetal resin, with options for aluminum and stainless with acrylic port.

"We wanted to design a camera that allowed our customers who already have our equipment to make a simple transition to HD. They just need to buy the camera and a new DVR to go with their existing cable, console and light," said Jeff Mayfield, VP of Outland.

www.outlandtech.com

HAL extends XBAT service portfolio

Sperry Drilling, a Halliburton (HAL) business line, has introduced a 4-3/4-in. slimhole size to its XBAT LWD service.

HAL's portfolio now includes 4-3/4, 6-3/4, 8 and 9-1/2-in. tools, which allows the XBAT tool to service wellbore holes ranging from 5-3/4 to 36-in.

The XBAT LWD service delivers acoustic measurements that are less sensitive to drilling noise and have a wider frequency response resulting in a greater signal-to-noise ratio. By combining multi-array azimuthal sonic velocity measurements with multi-axis ultrasonic stand-off measurements operators can improve their ability to determine rock properties.

The XBAT service analyzes data to optimize the drilling process by assisting in the mud window choice and provide borehole stability analysis; deliver wellbore placement data including time-to-depth seismic correlation while drilling and real-time synthetic seismograms, and provide gas detection, rock mechanics, complex lithology, porosity determination

with other LWD tools and porosity measurement without the need for nuclear sources **www.halliburton.com**

AeroGo unveils portable rigging kit

AeroGo debuted its portable Aero-Caster rigging kit designed to accommodate load configurations up to 40ft long and 64,000 lbs. It stores in a waterproof case and is compact and includes all of the components required to rig and move heavy loads in an industrial environment.

The rigging kit utilizes compressed air through air casters. Air casters offer superior load distribution by distributing the load weight over a much greater surface area than rollers or wheels, eliminating floor surface damage and the need for reinforced floors. Load movement is smooth and omni-directional, making it easy to precisely place heavy loads even in tight spaces. The rigging kit can be utilized in any work environment where there is an adequate floor surface and compressed air. **www.aerogo.com**

Permasense upgrades Data Manager 5

Permasense upgraded its data visualization and analysis software, Data Manager 5. Powered by the adaptive cross correlation (AXC) processing technique, it allows users to analyze the data gathered by Permasense's corrosion and erosion-monitoring sensors.

Combining established ultrasonic sensor technology with wireless communication, it sends real-time data automatically to the user's desk, enabling them to view equipment wall thicknesses and wall loss rates at critical or high risk locations. Users can monitor and analyze how the metalwork is coping with the demands placed upon it due to changes in process conditions, and affords online optimization and validation of corrosion or erosion mitigation strategies. **www.permasense.com**

Faces of the Industry

By Kelli Lauletta

This month's Faces of the Industry tells the career story of Jim Britton, CEO of Deepwater Corrosion Services, who knows a thing or two about weathering a downturn in oil prices. Born in the UK, but rightfully called an "honorary Texan," Jim had the hutzpah to start up an oil and gas service company in Houston during the rough ride of the 1980's. He figured out how to hedge his bets by diversifying his business to navigate successfully through booms and busts. He and his wife grew the business from a spare bedroom start up to a global multi-million dollar corrosion and asset integrity company.

OilOnline recently had an opportunity to visit Jim in his Houston office. Jim's face lit up when he discussed his entry into this business, why he focuses only on offshore projects, his key advice on "lean times" asset integrity strategies, and why he is upbeat about the future of the industry.

Tell us your story–how did you break into oil and gas?

My career began in the UK when the North Sea was coming online. I was a technician in a metallurgical laboratory that made welding electrodes, which was actually a pretty boring undertaking. I got into oil and gas when the UK switched from manufactured gas to natural gas. It was exciting time for me when I started as a field technician focused on pipeline projects and ended up working all over the world. I slowly went from field to office and worked my way up the ranks. In 1982, I got an opportunity to transfer to Houston.

What led to starting your own company?

I was at a juncture in my career as the company I worked for went through some restructuring and ownership changes. I either had to go back to the UK or find someone to hire me in Houston. The later wasn't easy because of my immigration status at the time. The only thing I could do was go into business for myself. So in 1986, my wife and I formed Deepwater Corrosion Services in a spare bedroom with no cash and just a credit card we had reserve on. It was tough but things worked out. You have to keep the faith.

We wanted to focus on manufacturing, however, the price of oil was around US$12-$13/bbl then. There was no new construction as more platforms were being removed than put in. So we got into maintenance and integrity management, which was somewhat shielded from the budgets cuts. We developed a risk-based inspection procedure and Exxon was the first company to give us a shot. That chapter in our business gave us a unique perspective in understanding the real problems with asset integrity. We used that knowledge to develop a solution called I-Rod to target localized corrosion damage. This particular solution really fueled our expansion into manufacturing, as we went from a few thousand in sales to over $10 million in sales last year on that one product alone.

What does it take to be a successful entrepreneur?

I'm an engineer by discipline with no formal business training. I grew into this role by building a company. One key to success is picking a sector and becoming the best you can be in that space. You can't be all things to all people. I chose the offshore industry as my focus and we don't even look at onshore work–we refer it out. Another key to succeeding as an entrepreneur is a drive to put the hours in. If you aren't prepared to do that, you have a slim chance of success. New entrepreneurs may also spring up during this downturn. I've found that a lot of people aren't "volunteer" entrepreneurs. They get downsized and take a chance on starting their own business. This might be a good opportunity for some to take their specialty and find a niche in the market.

Do you have a career high or peak you'd like to share?

One thing that really sticks out is when I developed a product to address a pipe support issue, our first purchase order was from Exxon. That was the first time we ever earned money from a product we developed in-house. That was a light bulb moment. It wasn't a very big purchase order, but it really got the fire started.

Have you seen a slowdown in the number of projects at your company?

We have seen some slowdown and we are getting calls from our customers looking for rate reductions and discounts. We are all in this together, so I have instructed my salesforce to work with those accounts to see how we can share the pain. Being hard-nosed on pricing is not where you need

Jim Britton

Jim Britton is the founder and CEO of Houston-based Deepwater Corrosion Services. He has worked in the offshore corrosion and asset integrity field since 1972. He was educated in the UK and began his offshore career in the UK North Sea. Jim has published numerous technical papers on offshore corrosion-related issues and holds several patents for technology associated with corrosion and asset integrity management. For nearly 30 years, Jim has focused on developing methods, products and technologies for controlling corrosion on virtually any type of offshore asset, from platforms and pipelines to FPSOs and wind farms.

to be in a market like this. These assets have got to be maintained or everyone loses out if these assets fail.

You have to have a business model that hedges Greenfield and Brownfield activity. We have gone to great lengths to structure our business to shift our emphasis in downturns to the inspection and maintenance oriented business. We have operated the company with that balance and it has helped us weather the storms.

In light of tighter budgets, what advice do you have for companies in their overall asset integrity strategy?
I would recommend looking at their assets very critically and performing a risk assessment as there are limited funds. You have to appreciate that some assets are more worthy of maintenance dollars than others. The secret is to get those priorities aligned and put the dollars where they do the most good.

How does the industry balance the talent equation during the downturn?
We need to be careful not to lose too much talent from the industry because when they are needed, they aren't going to be there. Also, many companies are dealing with the knowledge gap where they are lacking talent with 20 or more years of experience. At my company, we try to create a very structured career development program that includes mentoring to address the knowledge gap.

Also, the oil and gas industry as a whole doesn't force you into retirement. If you are willing to work and your brain is functioning, you can work as long as you want in a consulting role. That's what saved the industry when we went through the drought periods with a low number of petroleum engineers.

What are some key opportunities for companies in the offshore sector?
The offshore industry is finding really significant major energy reserves in the deepwater plays just off of the continental shelves. This industry is going to be around for a very long time. It never stops even with fluctuating oil prices. I see tremendous opportunity particularly in deepwater and ultra-deepwater segments.

There is a lot of talk about the near-term viability of the North Sea. What do you say?
The North Sea is a great area. It is like a phoenix as it keeps on coming up. Right now, it is challenged, but the UK government has a vested interest in keeping the offshore oil and gas business viable by providing tax relief.

We've invested heavily in positioning ourselves there. This is a major market but also a major source of innovative technology that really compliments what is happening here on the Gulf Coast. The most successful companies work between the US and the UK. The compliment between the European engineering style along with the American "can do" approach creates great synergies. Some wonderful stuff happens- it is a thing of beauty to see.

How would you like to be remembered?
I'd like to be remembered as a guy who brought a lot of new ideas to offshore and as running primarily a product development company. Ninety-five percent of what we sell is designed and built right here in Houston. I'd like to known as never giving up on the US as a manufacturing center. Texas easily has some of the best talent in the world when it comes to engineering and manufacturing. I'd like to think I'm doing what I can do to keep us in that lead position and not sell these job offshore. OE

Faces of the Industry will feature individuals who do extraordinary things for the industry and outside the industry. If you would like to nominate someone, please send an email to Kelli Lauletta.

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

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Numerology

US$**15.4** billion

Cost associated with phase 1 for the development of the Johan Sverdrup field. ▶ See page 12.

22,400 tonne

The weight of the Mariner jacket built by Dragados Offshore in Cadiz, Spain. ▶ See page 16.

The year DSATS was set up to accelerate the development and implementation of systems automation in the well drilling industry. ▶ See page 24.

US$**15**million

The investment made by Repsol, in partnership with IBM, to develop cognitive technologies. ▶ See page 28.

1000m

Water depth of Mexico's first deepwater development, the Lakach gas field. ▶ See page 32.

40 %

The average rate by which Resonance Enhanced Drilling could improve drilling rates. ▶ See page 34.

The average design life (in years) for an FPSO. ▶ See page 44.

278MMboe

Increased recovery expected follow the installations of the first subsea gas-compression facility at the Asgard field. ▶ See page 58.

107 m

the diameter of ENI's Goliat platform, which is currently on its way to Norway. ▶ See page 14.