Required reading for the Global Oil & Gas Industry since 1975

OE

▶ oedigital.com

The HPHT Issue

Offshore Engineer • December 2015


SUBSEA SERVICES
1,100 experts
21 IMR vessels
14 ROVs in operation
Largest fleet of AHC cranes
175,000 vessel operated hours per year
Supporting 1.4 M oil barrels daily production
www.bourbonoffshore.com
WE GO WHERE YOU GO
BOURBON
Building together a sea of trust
Contact: marketing@bourbon-subsea-services.com - Tel: +33 (0)4 91 13 67 22

Contents

ON THE COVER

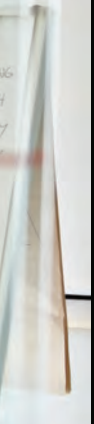
Turning up the heat. Despite being a mature province, the North Sea continues to reap rewards for those willing to go into new plays and expand the limits of technology. Maersk Oil's high-pressure, high-temperature Culzean field, a Maerk Oil artist's visualization of which adorns our cover, is an example. Read more on page 18. *Photo courtesy of Maersk Oil.*


Add Flow Transmitter Assembly
Imagine the clarity of a digital master set
Bluebeam® Revu® delivers PDF-based work process and collaboration solutions that enhance communication throughout the life of a project. Review the same digital master set with other stakeholders using a shared symbol library. Automatically track all comments and markup statuses for project accountability, and export the data for test pack compilation and reporting. Revu makes getting everyone on the same page from anywhere, at anytime, a reality.
Imagine the possibilities.
bluebeam.com/masterset
bluebeam®
NO LIMITS®
© Copyright 2015 Bluebeam Software, Inc.

Volume 40, Number 12 December 2015

Departments & Columns

What do you think will be the biggest breakthroughs next 1-2 years?







Currently @ OEdigital.com

Online Exclusive

Retreating from the US Arctic

The Nordica ice breaker. Photo by Judy Patrick/Shell.

The US is losing its opportunity to lay claim to Arctic exploration, falling behind countries such as Norway and Russia. Now with Shell and Statoil exiting Alaska's offshore, many in the industry and in politics are wondering how to salvage Alaskan offshore exploration. Jerry Lee reports.

What's Trending

Offshore investments

- **Eni in US$2 billion Egypt investment**
- **Premier Oil sells Norway business**
- **Newfoundland region gets US$907 million in bids**

Photo from Newfoundland and Labrador Tourism.

People

BOEM names GoM regional director

Mike Celata has been appointed BOEM regional director of the Gulf of Mexico Outer Continental Shelf region, effective immediately. Celata has been with BOEM and its predecessor agencies since 1988, and has served as acting regional director since March.

Voices

Back to the future. Despite the current down market, OE asked:

What do you think will be the biggest breakthroughs next 1-2 years?

The realization that we need to act now to kill complexity will be the biggest breakthrough for the future survival of the industry. We have systematically added layer upon layer of complexity and this is the core reason why projects have regularly failed to stay within budgets and timetables.

At US$50/bbl there is no margin, and worse, it is below internal cost level. In reality, it is unsustainable and the industry will not be saved even if the oil price picks up. We must direct our ingenuity towards less complexity – a creation of a 'smarter' space. This calls for collaboration across the value chain – from pore to pipeline, from feasibility to operations. We must have the courage to think differently and challenge current practices."

Liv Hovem, Director of Division, Europe and Africa, DNV GL – Oil & Gas

Whilst sustained low oil prices will keep capital and operational spend down, production must be maintained or even increased to cover costs – placing assets under strain. Survival requires more than just cutting costs. Producers need to adapt to smarter ways of working. Key to this will be the adoption of online monitoring technologies to gather field data and deliver it to a centralized decision making unit. These systems have the proven potential to transform operational decision making quality – saving money and increasing safety as data no longer needs to be manually captured in the field.

Jake Davies, Marketing Director, Permasense

With the fall in oil price, the next two years will see the industry focus on extending the life of offshore assets in a safe manner, whilst improving efficiency. The pressure of lean operating costs will see automation come to the fore which in turn, will drive requirements for remote monitoring, bringing with it the challenge of managing "big data".

The use of remote monitoring systems in the field, coupled with the clever interpretation of the resultant data sets, will play an integral role in optimizing operations. Taking the marine environment as an example, weather, sea states and ocean conditions can produce unpredictable challenges for operations and the extension of the life of an asset. Linking and optimizing the way we operate through the use of remote monitoring and feeding this data input into the development of clever learning and modelling systems, will improve our understanding of not only the environment, but the way we design and operate our assets. The technology is already available to link multiple sensors and models to support automotive operations; what we need now is a more collaborative approach to help optimize the way in which we manage the data output to benefit the industry as a whole, whilst ensuring safety is not compromised.

Louise Ledgard, Head of Oil & Gas Business Development, BMT Group Ltd.

As the industry continues to push the boundaries with deepwater technologies, an area I see ripe for advancement is enhanced completion techniques for low permeability reservoirs. At BHP Billiton, we are exploring ways that we can apply the complex hydraulic fracturing techniques used in our onshore unconventional plays to greatly improve the productivity of lower quality rock in some of the new deepwater plays. Success would help unlock new opportunities across the Gulf of Mexico, both in the US and Mexico, much like what we have seen in the Lower 48 and would help lower the economic threshold for development.

David Purvis, Vice President, Engineering, BHP Billiton Petroleum

In the current environment drilling contractors and service companies are under immense pressure from clients to cut costs by bringing efficiency gains to the well construction operations and at the same time, reducing personnel on board.

Autonomous drilling will evolve more so by enabling pieces of equipment to become more intelligent, allowing them to make decisions and respond immediately to any problem it encounters. Remote operation centers will also become more advanced due to obtaining further control of drill floor machines.

Advanced real time data centers will be utilized flagging the drillers of potential complications in the well construction and allowing the drilling parameters to be adjusted before it becomes a problem; improving decision making time, maintenance and visibility.

Scott Sivewright, TRS Global Technology Development and Implementation Manager, Weatherford

The next big industry breakthrough in oil and gas will occur as a wave of digitization transforms the operations technology landscape, creating a bridge between information technology, operations technology, and the industrial internet of things. With downtime as high as 10%, the industry needs better reliability and maintenance of facilities, equipment and process. It is estimated that by analyzing all their data, oil and gas companies can improve production by 6% to 8%.

When the oilfield meets the Industrial Internet of Things, operators can capture enormous volumes of data and then seamlessly turn that information into actionable insights to optimize their machines, people, and processes. Suppliers will contribute through the creation of 'digital twins' - a digital native for every physical machine. Digital twins combine physics based with analytical based models to be used for simulations, which will be run in parallel in the cloud at fractions of the cost of yesterday's supercomputers. These digital capabilities promise to bring the industry to unprecedented levels of productivity.

Peter Lawson, General Manager Software & Solutions, GE Oil & Gas

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

Undercurrents

A look back

40 years of OE

As 2015 – ***OE's*** 40th anniversary year – comes to a close, it's only natural to want to reflect on the year that was. Only 12 months ago, there was a feeling that the dip in oil prices might not be as bad as past downturns.

But, as the year went on, operators and contractors have started to see the writing on the wall: it is widely accepted that the days of >US$100/bbl oil are long gone and won't be back any time soon, if ever again if you believe some.

The thought on most minds in the industry is how to correct what had become an environment of excessive spending and excessive cost. Unfortunately, but predictably, the first rounds of spending cuts came in the form of staff cuts, with industry job loss estimates now at well over 200,000. Most expect more losses to come in 2016, as more and more companies are forced to downsize from quarter to quarter.

Right now, in such an environment, it may be hard to be positive. But, it's the one thing we must do. Investment needs to continue in research and development, and in continuing to be innovative, not just despite the downturn, but also because of it. Going forward, it will be interesting to see what technologies companies continue to champion during the downturn.

One area continuing to receive investment dollars is in the high-pressure, high-temperature (HPHT) realm, and that's why we have devoted our December issue to the topic. Across the issue, we cover HPHT technologies and projects, from Maersk Oil's North Sea Culzean field and 20,000 psi BOPs, to new umbilicals and more.

We would also like to share our recent success at the Business Marketing Association Houston Chapter's Lantern Awards where ***OE***'s parent company, AtComedia, picked up three awards (Original Illustration, Integrated Marketing Communications Program, and Rookie of the Year) in November for our ***OE*** 40th Anniversary Edition Monopoly. We couldn't be more excited and honored to win these accolades (*shown, left*).

And finally, as this year has been such a milestone for ***OE*** – 40 years of *Offshore Engineer*! – Some of the editorial staff have spent some time reflecting on the magazine's legacy, and leafing through plenty of back issues.

OE has always worked hard to deliver technical content that is both fun and interesting, hopefully opening doors to new solutions and ideas. As we enter our 41st year, we pledge to continue that tradition. That's the mission we aspire to. OE

ATCOmedia
Atlantic Communications Media

AtComedia
1635 W. Alabama
Houston, Texas 77006-4101, USA
Tel: +1-713-529-1616 | Fax: +1-713-529-0936
email: info@atcomedia.com

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

BPA WORLDWIDE BUSINESS

US POSTAL INFORMATION
Offshore Engineer (USPS 017-058) (ISSN 0305-876X) is published monthly by AtComedia LLC, 1635 W. Alabama, Houston, TX 77006-4196. Periodicals postage paid at Houston, TX and additional offices.
Postmaster: send address changes to Offshore Engineer, AtComedia, Po Box 47162, Plymouth, MN. 55447

OE

PUBLISHING & MARKETING
Chairman
Shaun Wymes
swymes@atcomedia.com
President/Publisher
Brion Palmer
bpalmer@atcomedia.com
Associate Publisher
Neil Levett
neil@aladltd.co.uk

EDITORIAL
Managing Editor
Audrey Leon
aleon@atcomedia.com
European Editor
Elaine Maslin
emaslin@atcomedia.com
Web Editor
Melissa Sustaita
msustaita@atcomedia.com
Contributors
Greg Hale
Heather Saucier
Editorial Assistant
Jerry Lee
Editorial Intern
Elia Barnett

ART AND PRODUCTION
Bonnie James
Verzell James

CONFERENCES & EVENTS
Events Coordinator
Jennifer Granda
jgranda@atcomedia.com
Exhibition/Sponsorship Sales
Gisset Capriles
gcapriles@atcomedia.com

PRINT
Quad Graphics, West Allis, Wisconsin, USA

EDITORIAL ADVISORS
John Chianis, *Houston Offshore Engineering*
Susan Cunningham, *Noble Energy*
Marshall DeLuca, *Wison Floating Systems*
Edward Heerema, *Allseas Marine Contractors*
Kevin Lacy, *Talisman Energy*
Dan Mueller, *ConocoPhillips*
Brian Skeels, *FMC Technologies*

SUBSCRIPTIONS
To subscribe or update details, email: subservices@atcomedia.com or visit oedigital.com. Rates $160/year for non-qualified requests. $20 for individual copy.

CIRCULATION
Inquiries about back issues or delivery problems should be directed to subservices@atcomedia.com

REPRINTS
Print and electronic reprints are available for an upcoming conference or for use as a marketing tool. Reprinted on quality stock with advertisements removed, our minimum order is a quantity of 100. For more information, call Jill Kaletha at Foster Printing: 1-866-879-9144 ext.168 or email jillk@fosterprinting.com

DIGITAL
www.oedigital.com
Facebook: www.facebook.com/pages/Offshore-Engineer-Magazine/108429650975
Twitter: twitter.com/OEdigital
Linked in: www.linkedin.com/groups/OE-Offshore-Engineer-4412993

Opinion

Tore Halvorsen, FMC Technologies

ThoughtStream

Driving cost down on a sustainable basis

Even before the drastic drop in oil prices, deepwater extraction costs were under examination, as costs had nearly quadrupled in the past 10 years. The price collapse has created a greater urgency for rethinking how the industry does business and operators and suppliers are more receptive to collaborating in new ways.

More than 40 years of subsea developments have provided a wealth of experience that must be leveraged to create common, standard specifications to propel efficiency in the subsea industry. Supplier-based standards have the potential to lower costs, shorten lead times and improve quality and reliability for multiple operators.

Cost reduction through volume

In order to leverage economies of scale, suppliers need to buy in volume. However, buying in volume requires alignment in specifications. Today, operators typically put their own technical requirements on top of the industry standards such as ISO, API or NORSOK, effectively undermining any possibility to leverage volume. As mentioned before, decades of experience can inform suppliers' standards and provide the required level of confidence to operators, especially on critical areas, such as risk mitigation and equipment reliability.

Configuration versus customization

A significant amount of application engineering hours can be saved if we move from the current "engineered to order" model to a model of "configured to order." When operators order based on functional requirements rather than technical requirements, suppliers can produce a proven solution that will meet or exceed performance expectations. Pre-engineered, modular solutions can economically accommodate a wide variety of requirements. These solutions can then be configured to meet customers' project-specific needs.

A "configured to order" model allows suppliers to leverage the purchase of raw materials in bulk and provides a more economical way to stock parts, saving time and money. In a recent internal study, we found that we were able to reduce lead time by 30-50% when our customers accepted our design rather than requiring us to create a customer-specific solution. In addition, a cost reduction of 20-40% was realized.

"Standard equipment systems allow for intervention tooling to be shared from project to project and can be installed using the same processes and procedures. And it stands to reason that the more times the same procedure is performed, efficiencies are found and safety and reliability improves."

For example, a choke module made to a customer's specifications had almost 460 components – almost all of them unique pieces requiring specific documentation and control. Our standard choke module has 300 components with only 30 unique pieces for which standard documentation and controls were used. Hardware costs were reduced 33%.

Improved flexibility and interchangeability

While a good portion of the cost and time saving benefits of standardization are realized during the manufacturing of the project, the payoff continues throughout the life of the field. Standard equipment systems allow for intervention tooling to be shared from project to project and can be installed using the same processes and procedures. And it stands to reason that the more times the same procedure is performed, efficiencies are found and safety and reliability improves.

Five operators, one standard

An example of the industry embracing the idea of standardization is the HPHT joint industry program (JIP) formed by FMC Technologies and five operators: Anadarko, BP, Chevron, ConocoPhillips, and Shell. The partners have agreed to jointly develop a new generation of standardized subsea production equipment and systems designed to meet the technical challenges of producing oil and gas from deepwater reservoirs with pressures of up to 20,000psi and temperatures of 350°F at the mudline. Standardization of materials, processes, and interfaces, as well as the enhancement of reliability and operability will improve overall deepwater development, while significantly reducing cost to the partners.

Downturns are difficult, but they often lead to positive change. Converging to vendor-based standardization is a positive change I hope the industry continues to embrace. OE

__Tore Halvorsen__ is Senior Vice President of Subsea Technologies at FMC Technologies, a position held since 2011. He was previously senior vice president of global subsea production systems and has also served as vice president of subsea production systems with oversight of Europe, Africa, Canada, and Asia Pacific.

Halvorsen was managing director of FMC Kongsberg Subsea in 1994 following his promotion to director of subsea systems when FMC Technologies acquired Kongsberg Offshore in 1993. He joined Kongsberg Offshore in 1980 as technical manager for subsea systems.

Halvorsen has a master's degree in mechanical engineering from the Norwegian Institute of Technology in Trondheim, Norway.

Hosted by: Marubeni Oil & Gas (USA) Inc, Cross Group Incorporated

Organized by: OE Offshore Engineer

Sponsored by: AkerSolutions, DOF Subsea, FTO Services, Baker Hughes, IHC, NOV, Oceaneering, OneSubsea A Cameron & Schlumberger Company

Global E&P Briefs

A Statoil exits Alaska

After the Obama administration rejected Statoil's lease suspension requests, the Norwegian operator has exited its Alaskan leases in the Chukchi Sea, finding them no longer competitive.

Statoil held 16 operated leases in the Chukchi Sea, northwest of Prudhoe Bay, 37mi north of Shell's abandoned Burger gas discovery.

In addition to the 16 operated leases, Statoil will also exit stake in 50 leases that are operated by Houston-based ConocoPhillips, also in the Chukchi Sea, with expiration dates set in 2020.

B Chevron hits at Anchor

Chevron's Anchor discovery proved successful oil pay in the Lower Tertiary Wilcox Trend, in the US Gulf of Mexico. Chevron began drilling at the appraisal well in June 2015 and encountered 694ft (211m) of net oil pay.

According to the company, a hydrocarbon column of at least 1800ft (549m) in the Lower Tertiary Wilcox reservoirs at Anchor was confirmed. Complete appraisal of the field will require further delineation wells and technical studies.

C Noble brings Big Bend online

Production has begun from Noble's Big Bend oil development in Mississippi Canyon 698 of the deepwater Gulf of Mexico.

Noble and partners expect the single-well field to reach a maximum gross production rate of approximately 20,000 boe/d. Approximately 90% of the volumes being produced from Big Bend are oil.

Big Bend is part of the Rio Grande complex, which includes the Troubador and Dantzler discoveries.

D Shell approved for Shelburne

The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) approved for Shell to begin its Shelburne Basin deepwater drilling program 250km off Nova Scotia. While approval has been granted, Shell is still required to seek approval from CNSOPB before drilling both planned wells, Cheshire and Monterey Jack.

The *Stena IceMAX* drilling unit, which will be used for the program, is carrying out preparatory work prior to the start of drilling operations.

E Canadian bid round a success

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) received more than US$907 million ($1.2 million CAD) in bids to explore about 2.6 million hectares of offshore area.

C-NLOPB received seven successful bids out of 11 parcel in the eastern Newfoundland region, north of the Jeanne d'Arc basin in the Grand Banks. Overall, 13 bids were submitted, and nine companies participated.

At 139,477 hectares, NL15-01-09 was the most expensive parcel at $318.6 million ($423.2 million CAD), which went to Statoil Canada, which also won six parcels as either and individual company, or as part of a joint venture.

The largest parcel, NL15-01-02, at 274,732 hectares went to the joint venture consisting of Chevron Canada (35%) Statoil Canada (35%), and BG International (30%), with a winning bid of $32.5 million ($43.2 million CAD).

F Humpback fails to impress

Noble Energy came up empty on its Humpback exploration well offshore the Falkland Islands. The well is now being plugged and abandoned after encountering non-commercial quantities of crude oil and natural gas.

Humpback was drilled in the Fitzroy sub-basin of the Southern Area License. The company said that it will undertake a full well assessment and integrate drilling results into its geologic models to determine remaining exploration potential in the Southern Area License.

G Petrobras declares Sépia Leste viable

Brazil's Petrobras has declared Sépia Leste in the Santos basin pre-salt area, offshore Rio de Janeiro, commercial with an estimated 130 MMboe recoverable resources.

The oil accumulation is northwest of the Júpiter discovery evaluation plan (PAD) in Block BM-S-24, about 250km off Rio de Janeiro's coastline at 2165m water depth.

H Eni makes Congo discovery

Italy's Eni encountered a new oil and condensate discovery in the Marine XII block, offshore Congo. The Nkala Marine prospect is in Marine XII block, about 20km from the coast and 3km from the Nene Marine field, and is already in production.

Eni expects the Nkala Marine 1 pre-salt exploration well to have a potential of 250-350 MMboe in place.

Altogether, the Italian explorer is estimating that the resources in place of oil and gas discoveries made in the

pre-salt Marine XII block is to be about 5.8 billion boe.

I Cairn spuds SNE-2

Cairn Energy has spud the first appraisal well on the SNE oil field 100km off Senegal.

The SNE-2 well will be drilled in approximately 1100m of water and drilled to 2770m TDVSS before an evaluation program including logging, coring and flow testing is undertaken.

Three evaluation wells, SNE-2, SNE-3 and BEL-1, will be drilled back-to-back in a program that is expected to complete in mid-2016. Both SNE-2 and SNE-3 appraisal wells will be logged, cored and flow tested. The BEL-1 well will appraise the northern portion of the SNE oil field and evaluate the untested Buried Hills play.

The aim of the appraisal program is to progress towards proving a minimum economic field size for the SNE discovery, which FAR estimates to be approximately 200 MMbbl.

J Kosmos in Mauritania find

Kosmos Energy has hit natural gas at its Marsouin-1 exploration well, off Mauritania, marking its second significant discovery in the area.

Marsouin-1 is in the northern part of the C8 block. The well, drilled with the *Atwood Achiever* rig, encountered 70m (230ft) of net gas pay in Upper and Lower Cenomanian intervals comprised of excellent quality reservoir sands, Kosmos said.

K Green light for Edvard Greig

Norway's Norwegian Petroleum Directorate (NPD) has given Lundin the green light to start production from the Edvard Greig field.

The field is in production license 338 in the Norwegian sector of the North Sea. According to the NPD, the project is on schedule with costs slightly increased compared to initial estimates.

Edvard Grieg is on the Utsira High, about 35km south of the Grane and Balder fields. It is being developed using a stand-alone processing platform on a steel-jacket structure.

The oil will be transported via pipeline (EGOP) to the Grane oil pipeline and on to the Sture Terminal north of Bergen. The gas will be transported via a separate pipeline (UHGP), which is tied-in to the transport system on the UK side (SAGE).

L Greater Stella remains on track

Ithaca Energy's delayed Greater Stella Area development remains on track for first production in Q2 2016. Ithaca says sailaway of the FPF-1 floating production facility from the Remontowa Shipyard in Gdansk, Poland, is due in Q1, with commissioning works underway under contractor Petrofac.

Ithaca says full completion of the commissioning works while the vessel is in the yard is key to avoiding an extended period of more complicated offshore commissioning activities.

Offshore, installation of all the subsea infrastructure required prior to the arrival of the FPF-1 is complete. A five well Stella development drilling campaign had already been completed in April 2015.

M Eni taps more gas at Guendalina

Eni has completed track well GU2-Dir A at the Guendalina gas field in the Northern Adriatic, offshore Italy. The side track reached a planned total depth of 3276m. All target horizons within the Pliocene were gas-bearing and penetrated in an up-dip position with anticipated reservoir characteristics. Additionally, two deeper gas levels were encountered that have been perforated as part of a dual string completion. The rig moved off location and production has now resumed. Total production from the field is stabilized at approximately 440,000 scm/d gross.

N BP fast-tracks Atoll

BP and the Egyptian government have signed a heads of agreement to rapidly progress the development of the Atoll deepwater field off Egypt.

The deal will enable first production to be expedited from an estimated 1.5 Tcf of gas resources and 31 MMbbl of condensates in the Atoll field, with production anticipated to begin in 2018.

Atoll, in the North Damietta Offshore Concession in the East Nile Delta, will consist of two phases. The first phase consists of two development wells tied back to existing infrastructure, and production expected to start up in 2018. Pharaonic Petroleum Co. (PhPC), BP's joint venture with EGAS and Eni, will operate the development.

O Ophir's Thai well dispoints

Ophir Energy came up dry at the first well of its two-well drilling campaign in block G4/50 offshore Thailand.

The G4/50-10 well, in the Soy Siam prospect, reached 1627m depth using the Emerald Vantage jackup rig.

Although, the well encountered the primary Miocene reservoir targets, all reservoirs were dry and no hydrocarbon was encountered. The well has been plugged and abandoned as a dry hole.

P Lundin spuds Selada-1

Lundin Malaysia has started drilling the Selada-1 exploration well in block PM308A offshore Malaysia.

Located 14km south of the Bertam field, Selada-1 will be drilled to 1700m below mean sea level using the West Prospero jackup rig. The drilling is expected to take 30 days and will target hydrocarbons in Miocene aged sands.

Q JV in Sturgeon find off Vietnam

Vietsovpetro, a joint venture between Zarubezhneft and Petrovietnam, made a commercial discovery at the Sturgeon field off Vietnam.

The exploration well CT-3X in block 09/3-12 achieved a dry oil free flow to surface from the productive horizons of more than 1800-tons/d.

Block 09-3/12 is located in the South Conson basin, 150km southeast from Vung Tau, 20km east from Bach Ho field.

R PNG survey begins

Searcher Seismic has begun the Haere 2D seismic survey offshore Papua New Guinea (PNG). The survey, in cooperation with the Department of Petroleum and Energy (DPE) and project partner BGP, comprises 17,000km of 2D long-offset, high resolution, broadband seismic over the Gulf of Papua.

"Deep grabens in the area are believed to contain extensive Mesozoic and Palaeozoic sediments," said Rachel Masters, global sales manager at Searcher. "Which may be associated with multiple unexplored petroleum systems, highlighting the prospectivity of the Gulf of Papua."

The *BGP Explorer* has now mobilized for the project.

S No pay at Sea Lion-1

After spudding the Sea Lion-1 prospect off the coast of Victoria, southeast Australia, in late October Hibiscus Petroleum has come up empty.

Partner 3D Oil said that wireline evaluation and sampling of formation fluids over zones of interest identified on preliminary Sea Lion-1 data have been completed. This work has confirmed that no zones of commercial hydrocarbons were encountered in the Sea Lion-1 well.

The Sea Lion prospect is northwest of the Gippsland Basin (permit VIC/P57) where Hibiscus holds a 75.1% interest, and is approximately 6km from the West Seahorse field (permit VIC/L31) where it holds a 100% interest. 3D Oil has a 24.9% interest in Vic/P57.

T Mitsui adds Kipper stake

Mitsui has reached an agreement with Australia's Santos concerning the acquisition of Santos' 35% working interest in the Kipper gas and condensate field offshore Southern Australia.

The Kipper field is in the Gippsland basin, approximately 45km off the coast of Victoria. Production of gas, condensate and liquid petroleum gas is expected to start in 2016, and the products are planned to be supplied to domestic market.

Contract Briefs

Atwood inks multiple contacts

Atwood Oceanics has won two contracts in the Gulf of Mexico (GoM) and offshore Brazil.

An Atwood Oceanics subsidiary has agreed to a contract extension and rate adjustment with Noble Energy for the ultra deepwater rig *Atwood Advantage*, for a four well plug and abandonment (P&A) program. This extension adjusts the operating day rate to approximately US$240,000/d only during the four P&A wells and makes the new contract expiry date to approximately August 2017.

In addition an Atwood Oceanics subsidiary received a letter confirming selection for exclusive negotiations with an undisclosed operator to conclude agreement on a Q3 2017 drilling program offshore Brazil. The letter specifies a number of contractual items that have been agreed by the parties, including the commercial rates, well count, minimum term length, rig acceptance criteria, and the use of either the *Atwood Admiral* or *Atwood Archer* to drill the program.

MMA in Woodside deal

Woodside Energy awarded MMA Offshore a US$35 million (A$50 million) contract to provide three vessels to support Woodside's offshore Northwest Shelf, Pluto and AusOil production assets in Australia's North West region.

The three vessels to be chartered include two of MMA's purpose built offtake support vessels, the *Mermaid Sound* and the *Mermaid Strait* and a modern, high specification platform supply vessel, the *Mermaid Leeuwin*.

The contract for the three vessels is for a firm period plus a number of options. Should all options be exercised, the contract value would be approximately $77.4 million (A$110 million) in total.

Fugro awarded ROV gig

Fugro has been awarded a five-year contract for the provision of underwater services to Total E&P UK (TEP UK). Under the contract, which runs from July 2015 and includes extension options for a further two years, Fugro is providing a full range of remote operated vehicle (ROV) services to conduct inspection, repair and maintenance activities on TEP UK pipelines, subsea assets and jackets. The contract follows Fugro's recent ROV inspection campaign for TEP UK in the Central Graben area.

McDermott wins RasGas EPCI

McDermott International has won a large brownfield contract by RasGas for the engineering, procurement, construction and installation (EPCI) of a flow assurance and looping project and topside modifications offshore Qatar. The work will involve 74mi of 6in and 8in pipeline and topside modifications and is scheduled for completion by the end of the Q3 2017.

Engineering, procurement and fabrication is expected to be performed by McDermott's teams based in Dubai, UAE. Vessels from the McDermott global fleet are expected to undertake the installation work.

Civmec picks up fabrication work

Technip Oceania has awarded Civmec a fabrication contract for 17 subsea jumper spools and associated lifting equipment for Shell's Prelude FLNG project. Civmec said it has gained valuable experience through the delivery of spools for another Technip subsea project and will commence work immediately. ■

The Culzean wellhead jacket under fabrication.
Images from Maersk Oil.

Taming Culzean

Mastering high-pressure, high-temperature reservoirs has been a UK North Sea challenge for more than a decade. Maersk Oil is taking lessons learned by others and applying them to the Culzean field.

By Elaine Maslin

With few major upstream projects reaching final investment decision in the current climate, Maersk Oil's Culzean is one of the UK North Sea's bright sparks.

Approved in August 2015, the US$4.7 billion, 270 MMboe plus project is not just a significant project, signaling contracts and jobs, it is also complex, with high-pressure and high-temperature (HPHT) reservoirs, offering challenges around materials selection, drilling, well completion design, and field drainage philosophy, to name but a few.

Maersk Oil's development plan for Culzean, which could provide about 5% of the UK's total gas consumption by 2020-21, is a new three-platform installation, consisting a 12-slot wellhead platform, central processing facility and a utilities and living quarters platform, construction on which is now under way.

The reservoir, in about 90m water depth, is approximately 4300m below sea level, reaching some 348°F or 176°C, and around 13,500psi, some 240km from Aberdeen. It is not far from the Elgin, Franklin and Shearwater HPHT fields, operated by Total and Shell, respectively, in the East Central Graben area of the central North Sea.

Maersk expects first gas in 2019, and plateau production to be in the range of 300-450 MMscf/d and 25,000 b/d condensate.

Beginnings

Although the area was tested in 1986, Culzean itself was discovered in late 2008, with discovery well (22/25a-9z), in Block 22/25, using the Ensco 101 heavy duty jackup rig. This was Maersk Oil's first UK HPHT exploration well. The discovery well found gas and condensate within the target reservoirs of Triassic and Jurassic age. Further appraisal was then carried out during 2009-12, with three, 5km-long wells.

It was always likely to be a HPHT reservoir at that depth, says Martin Urquhart, project director. "The pressure is equivalent to being under 9km of water and the temperature to what you roast your Sunday dinner at," he says. "Because of the reservoirs we were targeting, at the depths we were targeting, you know it's likely going to be HPHT."

The appraisal campaign had to be efficient, due to the high costs involved in drilling such deep, high-temperature and

uHPHT allowance

Culzean is the first development to benefit from a new ultra high-pressure, high-temperature (uHPHT) cluster tax allowance on the UK Continental Shelf. The allowance was designed to encourage the development of uHPHT fields that are economic, but not commercially viable because of the current 62% tax imposed on normal fields.

"The project may signal a turning point for the crisis facing the UK North Sea where projects continue to be delayed or put on hold," says Rebecca Edgill, IHS. "And the allowance including a cluster pressure wells. "To end up with an 8.5in hole that deep down you need a 36in hole at the top," Urquhart says, hinting at the scale of these wells. This means any appraisal campaign is going to be costly, therefore has to be has to be well thought through and effective.

One of the biggest challenges of HPHT drilling is the pore pressure and the fracture gradient, Urquhart says, resulting in narrow drilling windows. The pore pressure on Culzean is high and very close to the fracture gradient. If, during drilling, the mud weights are too highly over-balanced, the reservoir can fracture, leading to mud-loss and loss of well control. To make matters even more interesting, these central North Sea reservoirs can have complex geological histories, making predictability difficult.

"Your drilling window is narrow and that is a feature of most HPHT reservoirs," Urquhart says. "Generally, they are very close to blown traps. What this means is we have to calculate the weight of the oil-based mud very carefully. When we load up the mud to penetrate the reservoir we have to know exactly where we are in the geological sequence and associated pressure regime."

HPHT heritage

Maersk Oil has had the benefit of others having already been working in North Sea HPHT for some years. Total and Shell led the way with the Elgin, Franklin and Shearwater fields. Total was challenged with up to 370°F and 16,000psi on Elgin, brought on stream in 2000, with the neighboring Franklin field having similar figures and Shearwater having lower pressures but higher temperatures. Shearwater and Franklin also came onstream in 2000.

Back then, as with today, the operators worked together on solutions for these tricky reservoirs. Maersk Oil's Culzean Well Delivery Manager is also co-chair of Oil & Gas UK's HPHT Workgroup, which meets to discuss HPHT well life cycle issues and solutions. "The industry shares knowledge and experience in this area because of the risk profile," Urquhart says. "We have also been able to build on the legacy and experience of previous HPHT developments and develop an extremely robust design, for virgin pressure drilling and completion and for the later wells depleted drilling." In the wells space, the company has also used Rushmore Reviews, now part of IHS, to benchmark well design performance.

One of the key learnings has been around annuli management, especially following the 2012 Elgin platform leak (*OE*: *July 2014*), which Urquhart says is one of the main challenges with HPHT. "We have gone for a design with two fully-rated annuli to mitigate against well integrity issues and gas migration," he says.

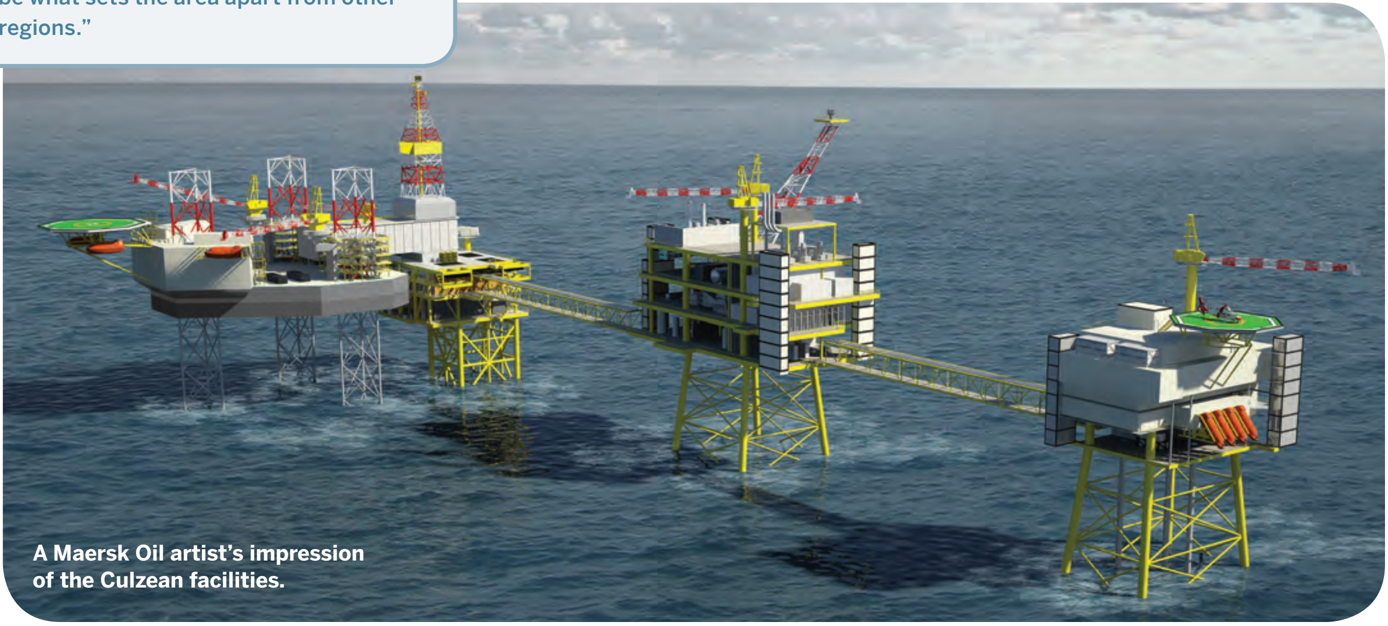
Martin Urquhart

Once the gas and condensate reaches the wellhead, the pressure is quickly choked down from around 11,500psi to ~90-100 bar. But to manage this process, and the fact that, as a result of the temperatures downhole, the wellhead, provided by Cameron on Culzean, has been designed to go up 500mm in height from cold, spring supports have been used, this together with flowline design and stress analysis ensures all these forces are controlled and dissipated. The pipe valves, manifold and pipe connected to the tree are all API 15,000psi – which can be a tough call when there are a limited number of manufacturers producing certain 15,000psi-rated valves.

Having had others come before has meant Maersk has also been able to benefit from existing supply chain materials qualification, at levels slightly higher than it actually needs, adding its own specification, within industry standards, where it needs to. In order to meet some criteria needed for Culzean specific compositions, hot isostatic pressing (HIP) has been used for some components, including the manifold. HIP manufacturing – first developed to produce synthetic diamonds and nuclear fuel elements in the 1950s - reduces the porosity of metals and creates a homogenous crystalline structure, at the same time reducing machining or welding.

hub means that the area shouldn't just see new developments, but also an increase in exploration and appraisal.

"With the introduction of a tax break for uHPHT fields off the UK, along with the simultaneous advances in technology, now is a better time than ever for operators to develop HPHT assets and to continue exploration and appraisal in nearby areas," she says. "Maybe, since the introduction of the tax allowance, the UK will see more and more uHPHT developments offshore, and that could be what sets the area apart from other regions."



A Maersk Oil artist's impression of the Culzean facilities.

The Culzean wellhead jacket under fabrication.

"Given the challenges of welding such heavy wall material we have elected, where possible, to make sections utilizing the HIP process and connecting them together with Grayloc 15,000psi-rated hubs," Urquhart says, "This eliminates the need to weld completely."

Fully rated

While the pressure of the production stream at surface is dropped at the choke, the entire wellhead platform has been fully rated to 15,000psi, with an over pressure system, comprising four, fast-acting 15,000psi gate valves from Bel Valves, each weighing 6-tonne, compared to just 500kg for an equivalent normal pressure, normal temperature valve. By taking the decision to have three separate facilities linked by bridges, Maersk has also been able to achieve a temporary refuge impairment frequency of zero on the utilities and living quarters platform.

Exotic materials, primarily corrosion resistant alloys and titanium are prevalent throughout the process piping systems, separators, coolers, pumps and valves due to the nature of the Culzean gas and fluid properties and the temperature and pressure that the systems are required to operate at.

Maersk also has another challenge – dealing with some 12% wax in the condensate and the associated flow assurance issues was the reason why the field needed a floating storage and offloading vessel (FSO) instead of being able to produce as a tie-in to existing liquid export infrastructure.

Japan's MODEC is building the floating storage and offloading vessel for the project (the company's first UK North Sea project), at Sembcorp Marine's Tuas and Tanjong Kling facilities. It will have 350,000 bbl storage capacity, and an internal turret system supplied by MODEC subsidiary SOFEC.

"This small rate of waxy condensate has a big impact on the design of our liquid process facilities," Urquhart says. "We have four stages of separation to get it to a point where it can be exported to the tanker. Because the separation and stabilization process takes the pressure so low we then have off gas streams, which need to be compressed all the way back up to a much higher pressure in order to export into the CATS transmission system."

Maersk also wants to minimize manning on the facility, by using an advanced collaborative environment onshore with real time data from the process and safety equipment, via fiber optic link. The living quarters has room for 140 people, but only half of that will be used in the early years, until later in field life when the balance is taken up by well intervention teams.

Future proofing

Due to the way HPHT fields deplete, the drainage strategy is also important on Culzean. Maersk is pre-drilling three of the six development wells, which will come on stream sequentially at first gas effectively before virgin pressure drops. "We want to put as many wells in the ground ready to produce as the challenges of depletion drilling after production have to be factored in to the development," Urquhart says. Maersk will be using a newbuild heavy duty, JU-2000E jackup rig supplied by Hercules Offshore.

As well as accounting for the extra people on board needed for future intervention work, the facility has also been designed to take on intervention equipment. "Mid-life, most HPHT fields need some kind of intervention, such as scale squeeze or downhole safety valves checks," Urquhart says. "Once the drilling rig has gone, the top deck is designed to have a heavy duty coil well intervention spread so that once the reservoir comes down to 10,000psi, we can run heavy duty well interventions."

Construction underway

With first production planned for 2019, most of the key contracts have been awarded. Sembcorp Marine subsidiary SMOE is building the development's three topsides, the utilities and living quarters platform, the central processing facility including flare, the wellhead platform and finally the two connecting bridges.

The wellhead platform jacket and heavy duty jackup are on schedule for installation in Spring/Summer 2016, to start drilling the Culzean development wells. The jacket is being fabricated by Heerema in Vlissingen, the well access deck is being completed by Heerema Hartlepool. The heavy duty jackup will be on contract from Hercules Offshore, which is fabricating a new-build with Sembcorp Marine at their Tanjong Kling facility in Singapore.

Late October, the three topsides were in the kick off and ramp up phase, with Sembcorp Marine subsidiary SMOE. These will be assembled in the Admiralty yard facility in Singapore. SMOE have subcontracted the power generation module, bridges and flare to their UK facility at Lowestoft.

The two remaining jackets have been awarded to Heerema and they will be fabricated in Vlissingen with six pile clusters manufactured in Hartlepool.

Going to press, KBR was awarded a detailed design and engineering and follow-on services contract by SMOE for the topsides facilities on Culzean. Specifically, KBR will deliver the living quarters, central processing facility and wellhead decks for the three Culzean platforms. OE

Cutting the umbilical

Eliminating the umbilical has been targeted as a way to help make the exploitation of small pools more viable. Elaine Maslin reports on a string of new technologies which aim to do just that.

A spool piece fitted with Exnics collars. Photo from Exnics.

According to a recent study by the UK's Technology Leadership Board, there are 210 "small pools" of hydrocarbons (those containing less than 15 MMboe).

While recognized, these pools, containing 1.5 billion boe in total, remain undeveloped, due to their distance to existing infrastructure, their reservoir complexity or they are uneconomic because of their size.

An initiative in the UK is hoping to find technologies that will help unlock them – and most revolve around eradicating umbilicals.

An Exnics collar. Photo from Exnics.

The initiative is being pushed by Gordon Drummond, who leads of the UK's National Subsea Research Initiative (NSRI), an organization which aims to connect the subsea industry and academia to find solutions to industry challenges.

Eliminating the umbilical, and even potentially the pipeline, could save significant costs – a key requirement in today's market - and reducing infrastructure, installation time and assets, and maintenance concerns.

Gordon Drummond Photo from NSRI.

A number of technologies that could help achieve this aim were presented at an NSRI event, supported by Subsea UK, in Aberdeen, late September.

Andrew Connelly, NASCoM product line manager at Aberdeen-based through-water wireless communications firm Nautronix, one of the presenters, says: "Cost is key at the moment, including the cost impact of umbilicals, the lead time to procure them, plus deployment and support requirements."

For deepwater projects, the implications are even greater, he says, with deepwater umbilicals taking up significant deck space, and requiring more effort around connection and logistics, i.e. ROV or diver time, as well as suitable subsea construction vessels.

Start with control

Nautronix, recently acquired by Scotland-based Proserv, has offered to do away with the control and monitoring cable requirements in the umbilical with its NASCoM system, which has already been deployed on multiple oil and gas projects worldwide. The firm's acoustic through water communications technology has even been used as the primary control for BOPs in deepwater.

Connelly says: "We can't do much for wells products and chemicals, but we can look at control and monitoring. You don't need a control and monitoring umbilical. Removing this can save time around deployment. You don't need the work around the point to point connection. You can have one acoustic link on the vessel to multiple assets, which multiple vessels could also access. They could perform multiple control and logging functions for anything you want to do electrically subsea."

What's more, data processing, monitoring sensor data, and filtering data to give more relevant data back to the surface could all be done, to streamline operations.

Nautronix uses digital spread spectrum signaling, which is based on mobile phone technology, giving robust signaling, with data networks used to extend the range of the system. The range of Nautronix's NASCoM system is 3-5km horizontally, depending on local topology, or 6-7km vertically and it has no interference with other acoustic systems, due to the coded signal.

Next, subsea power

Exnics has focused on how to power services at the well site, without using an umbilical. "We realized no one was looking at the geothermal energy a well produces," says Stu Ellison, founder at Exnics. "There is a huge thermal potential at the mud line."

Exnics has studied using semiconductor material in a collar, which is installed around a subsea flowline in a two-part clamp and generates an electrical current which is then stored in lithium batteries from which the subsea power can be drawn down.

As an example, Exnics looked at the potential on the Devenick field, operated by TAQA. It is a 34km tie-back with two wells, with a wellhead temperature of about 140°C, according to their research. By assessing the production volume and phases, they worked out the thermal capacity and mass of each of the phases, the heat difference between the flow and the ambient temperature in the sea water around the pipeline was equivalent to 6.9MW of geothermal heat potential.

Ellison says each field is different so the Hot Rings power system is designed to be scalable to suit. Even if the geothermal heat potential at a certain field is relative low, the same power output can be achieved by 'daisy chaining' more Hot Rings in the train.

"There isn't an upper temperature limit, but you do have certain flow assurance criteria, i.e. temperatures at which it is not worth doing, the cut-off point is estimated to be sub 50°C," he says. "But there are not that many wells below 50°C. In the North Sea, most are in the high-60°C to 110°C range and HPHT wells can be much hotter"

From a flow assurance stand point, the amount of electrical power required and the heat needed to feed that generation needs to be considered so the production flow isn't taken down to a temperature at which hydrates or wax could form downstream. "For very waxy or heavy crudes, this probably isn't

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)	70	73	72	44
Deep (500-1500m)	23	19	29	15
Ultradeep (>1500m)	37	35	13	9
Total	130	127	114	68
Start of 2015	135	125	90	-
date comparison	-5	2	24	68

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	9	30.75	333.28
Deep	12	941.00	2195.00
Ultradeep	40	10,923.75	12,450.00
United States			
Shallow	14	86.30	234.00
Deep	19	722.27	818.48
Ultradeep	25	2791.50	3420.00
West Africa			
Shallow	109	3736.20	15,148.22
Deep	37	4622.50	5540.00
Ultradeep	13	1605.00	2160.00
Total	269	25,458.52	42,715.70
(last month)	(270)	(25,458.52)	(42,715.70)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	893	38,368.59	511,820.04
(last month)	(889)	38,242.09)	(511,028.44)
Deep	120	7,184.58	70,643.91
(last month)	(119)	(7198.58)	(71,043.91)
Ultradeep	83	15,648.25	31,097.00
(last month)	(82)	(15,378.25)	(30,997.00)
Total	1,096	61,201.42	613,560.95

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	42,137	(41,594)
Planned/ possible	24,618	(24,193)
	66,755	(66,787)
8-16in.		
Operational/ installed	83,497	(81,651)
Planned/ possible	49,627	(49,002)
	133,124	(130,653)
>16in.		
Operational/ installed	93,860	(92,607)
Planned/ possible	45,424	(38,461)
	139,284	(131,068)

Production systems worldwide

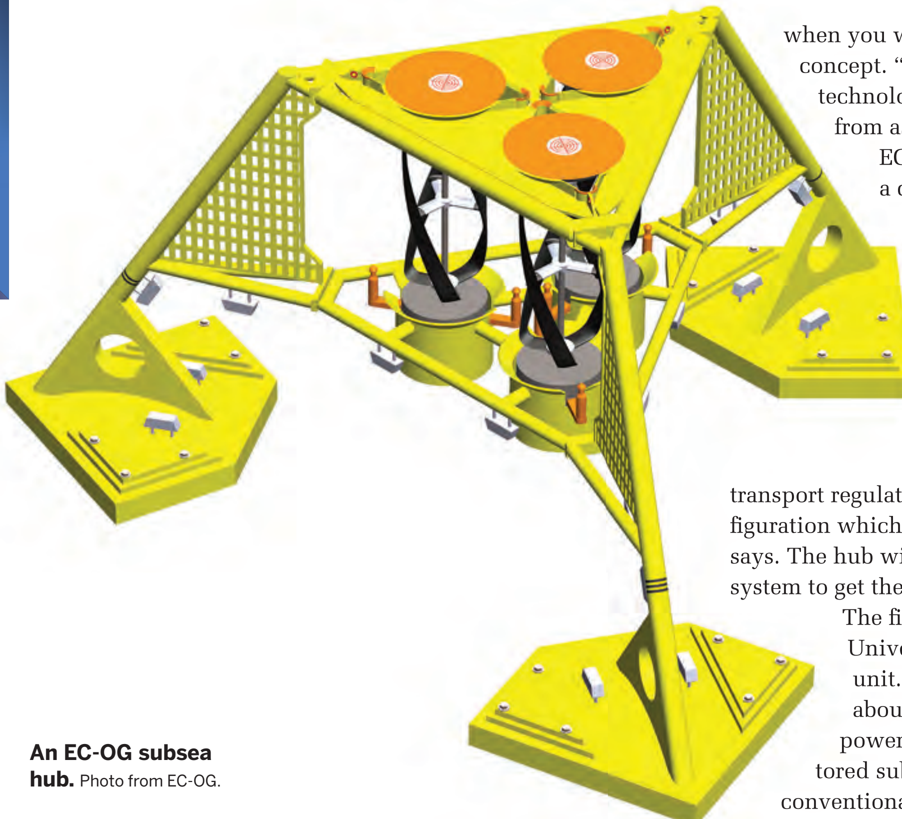
(operational and 2015 onwards)

Floaters		(last month)
Operational	275	(285)
Construction/ Conversion	47	(41)
Planned/possible	321	(347)
	643	(673)
Fixed platforms		
Operational	9269	(9302)
Construction/ Conversion	104	(117)
Planned/possible	1382	(1407)
	10,755	(10,826)
Subsea wells		
Operational	4859	(4783)
Develop	401	(271)
Planned/possible	6535	(6631)
	11,795	(11,685)

Global offshore reserves (mmboe) onstream by water depth

	2013	2014	2015	2016	2017	2018	2019
Shallow	23,027.00	14,528.45	38,085.01	24,057.70	19,846.90	19,400.16	27,209.30
(last month)	(22,856.00)	(14,528.45)	(37,823.29)	(24,420.96)	(19,433.05)	(19,959.89)	(25,506.62)
Deep	481.00	4469.26	4340.71	2237.76	2262.04	4512.78	6285.88
(last month)	(481.00)	(4469.26)	(4340.71)	(2237.76)	(2252.09)	(4534.73)	(6417.57)
Ultradeep	2917.00	2342.81	2037.21	2978.59	3287.44	5509.17	7318.54
(last month)	(2917.00)	(2342.81)	(1966.63)	(3049.17)	(3287.44)	(5221.54)	(7318.54)
Total	26,424.11	21,340.52	44,462.93	29,274.05	25,396.38	29,422.11	40,813.72

12 November 2015



An EC-OG subsea hub. Photo from EC-OG.

something you would consider," Ellison says. "But for typical crudes, condensate, gas, HPHT or any well with a meaningful water cut there is an opportunity to harvest the produced heat."

Stu Ellison
Photo from Exnics.

The technology itself – the Seebeck effect – has been around a long time. Thermoelectric generators or TEGs, are maintenance free and because of this they were used to power many space missions including Voyager, Ellison says. Since being developed for space TEG's have been commercially developed and are now available as a relatively cheap component. "It is now at a point where there are industrial applications and they can be bought off the shelf," Ellison says. The firm is now preparing to conduct demonstrations at their unit in Ellon.

Power alternatives

EC-OG, formed in 2013, has been developing a subsea power hub concept, an invention to use ocean currents to generate electrical power, and a full scale version of the concept is due to start trials next year.

The subsea power hub concept consists of three vertical axis turbines, each connected to direct drive DC power generators, and in turn batteries to store power, all housed in a no more than 7m-footprint over trawlable frame.

One unit can produce about 500w, according to EC-OG, with additional units to be daisy-chained if additional power is required.

The firm, which has been supported by a number of Scottish Enterprise "Smart Grants" to support trials of a scale subsea power hub. It is due to start full scale trials at the bottom of Loch Linnhe, at the Underwater Centre, Fort William, next year.

"Ocean current is predictable, and then there has been a massive leap in battery technology to store and deliver power when you want," says Richard Knox, the inventor of the concept. "Then there is the research combining the two technologies. Our aim was to get as much energy out from as small a footprint as possible."

EC-OG's tidal turbines are each just 2m high, in a configuration which optimizes the flow and power generation, and can be removed individually from the frame. As each has its own DC generator, there is built in redundancy, and they can start producing electricity with a current flow as low as 0.4m/sec.

Key to the design has been to create a system that can sit in a compact, over trawlable structure, which meets road transport regulations, for ease of logistics, and a turbine configuration which gets the most from the ocean current, Knox says. The hub will also have an intelligent energy management system to get the maximum life out of the battery.

The firm started testing a model at Newcastle University two years ago, using a one third scale unit. The testing at Fort William is due to run for about 18 months and will also demonstrate the power hub's ability to be remotely control and monitored subsea applications via a desk top, without the conventional umbilical.

While initially the concept was aimed at brownfield sites, where wells were being shut-in due to electrical failures, the firm is also looking at greenfield projects and even subsea surveillance. It could also be used as a power source for remote island communities.

"We are looking to offer a step change in electric current cost, and to use subsea power hub to extend life of subsea wells," Knox says. "We are looking at a truly disruptive technology which will reduce the cost of supplying electric power."

PowerBuoy

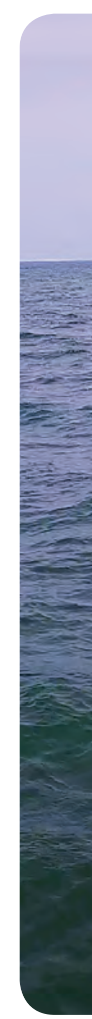
While Ocean Power Technologies has not quite done away with the need for a cable to transport the power from the source to the user, its PowerBuoy solution does offer a way to reduce the need for manned surface facilities or long step-out umbilicals to provide power for the likes of AUVs or power for electric Xmas trees.

PowerBouy is a wave energy power generation device, one of which is currently being used offshore New Jersey to collect metocean data, the firm says could be used through the life of field, from environmental impact assessment to front end engineering studies, operations and decommissioning, with sensors mounted from the device through the water column as well as above the surface.

The firm's first unit, APB-350, was built to produce 300w, but it has been producing 1000w offshore New Jersey. It was producing 25kW/hr late October. A larger unit, the PB10, is in the design phase.

"We have been looking at small units first, to prove the system, make sure it is reliable as a monitoring and data solution, and once it is proven reliable operationally, we can scale it up," says Paul Watson, director of business development UK & Europe at the firm.

Earlier this year, the firm formed an advisory panel with operators, manufacturers, services companies and sensor companies, to involve the industry in the design phase of a unit



that could supply power to seabed users. In October, it signed a memorandum of understanding the Gardline to jointly develop metocean monitoring and maritime security systems.

All in all, there are potential solutions out there to remove the umbilical. What was missing was a way to transport chemicals, such as MEG, for injection to the well site. But work is underway on this, too. For example, OceanWorks International, was awarded an engineering contract to help develop a deepwater permanent subsea pressure compensated chemical storage and injection system, as part of a project supported by the US Department of Energy, the Research Partnership for Securing Energy for America with support from the DeepStar program, as well as Baker Hughes and Fugro.

Oil major Total, working with French firm Doris Engineering, has also been exploring designs for subsea chemical injection systems, for both oil and gas subsea tie-backs, with a key benefit being reducing umbilical cost procurement and installation time. The longer-term goal would be to reduce the connections to an FPSO from the seabed to just the flowlines.

Drummond think's there is potential, thanks to these technologies, to do away with the umbilical. The next challenge will be getting rid of the export pipeline. "If you can get a light-powered chemical injection skid, we have done away with the umbilical. The next step is to do away with the pipeline," he says. OE

Ocean Power Technologies' PowerBuoy off New Jersey.
Photo from Ocean Power Technologies.

Rig stats

Analysis

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	109	85	24	77%
Jackup	399	286	113	71%
Semisub	151	110	41	72%
Tenders	31	19	12	61%
Total	690	500	190	72%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	37	35	2	94%
Jackup	23	7	16	30%
Semisub	18	15	3	83%
Tenders	N/A	N/A	N/A	N/A
Total	78	57	21	73%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	15	5	10	33%
Jackup	118	75	43	63%
Semisub	34	15	19	44%
Tenders	20	12	8	60%
Total	187	107	80	57%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	28	21	7	75%
Jackup	52	40	12	76%
Semisub	32	29	3	90%
Tenders	2	1	1	50%
Total	114	91	23	79%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	49	43	6	87%
Semisub	43	34	9	79%
Tenders	N/A	N/A	N/A	N/A
Total	92	77	15	83%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	109	91	18	83%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	114	94	20	82%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	23	21	2	91%
Jackup	23	18	5	78%
Semisub	11	9	2	81%
Tenders	9	6	3	66%
Total	66	54	12	81%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	2	1	1	50%
Semisub	2	2	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	4	3	1	75%

Source: InfieldRigs
18 November 2015

Ian Penman, senior global technical advisor, Halliburton
Photos from Offshore Energy Exhibition & Conference

Raising the bar

Getting HPHT right is a real challenge for today's industry, involving finding new materials, setting new standards and building competence in the industry. Elaine Maslin reports.

"Never underestimate a high-pressure, high-temperature well (HPHT) well." That's the advice of Bert Campfens, who, with 34 years' experience at Shell as senior drilling engineer has some authority on the matter. "Most of the time they [HPHT wells] move towards the ultra side, not to the other, and there is a lot more to it," he warns, not least in the competency of staff.

HPHT is a growing business in the offshore industry and it is getting hotter and into higher pressures. Generally, the standard definition for HPHT is around 10,000psi and 300°C. But, the envelope is increasingly being pushed.

Ian Penman, senior global technical advisor, Halliburton, told a session on HPHT at the Offshore Energy conference in Amsterdam in October: "Now it is fairly easy to attain downhole equipment that attains [10,000psi and 300°C]. We are moving into the more extreme 15,000psi and 360°C area," he says.

Campfens agrees. "10,000psi pressure and 350°F reservoir temperature is the current definition of HPHT. Today, [we are looking at] 20,000psi and close to 500°F and I think the industry has to start thinking." Both Campfens and Penman were speaking at a session on HPHT at Offshore Energy in Amsterdam.

Going into these types of play, without enough knowledge and expertise, can be a risky business, Campfens says, who was chairing the session. In work with Shell off Africa, "What could go wrong, did go wrong," he said. "We were fire-fighting all the time."

He said a proper survey wasn't done on local conditions, and the reservoir wasn't tested deeper than 10,000ft, which meant when the team got to 20,000ft, the reservoir temperature was found to be higher than normal, resulting in equipment issues. "We worked on the limits of casing and well design," he says.

Key, is making sure the organization has the competence to carry out such wells, Campfens says. "We didn't have staff who had any experience in HPHT. All but one became very nervous when things happened," he says.

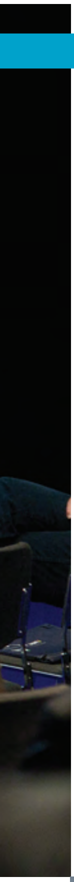
Setting standards

Indeed, the industry is doing some serious thinking about HPHT as the bar literally gets raised. "We are building qualified equipment to 15,000psi and 350°C, as we speak," Penman says. Penman is also involved in API Committee 19, which is drawing up a raft of new HPHT downhole completion standards for the Gulf of Mexico, which will likely spread beyond the US.

The API Committee 19 is looking at everything from elastomers to metals, testing for longevity for ultra-HPHT (uHPHT), in equipment including packers, subsurface safety valves, flow control nipples, plugs, etc., seal assemblies, latches, and liner hangers, Penman says. Some have already been published, others are close to being published and work is starting in other areas to complete a suite of new standards.

However, with more stringent standards, in most cases, the result will be longer testing cycles, Penman warned. "Before, typically between contract award and when had to put equipment on the ground was about one year, and that was quite difficult to do that. With this new API implications you are looking at doubling that. There is a whole lot more involvement going in to a HPHT situation."

Despite the extra time it will add, Campfens sees the API committee's work as progress. "For me, I see a huge step forward. There were no standards, how to get equipment, before. We are moving on."



A material challenge

Materials selection for HPHT well construction is still a major challenge, however. Henk Kramer, senior wells engineer, Nederlandse Aardolie Maatschappij (NAM), in the Netherlands, outlined a minefield of often conflicting requirements for materials selection in HPHT at Offshore Energy.

"In principle you want to make the production casing as light and thin as possible. In that case, you do not need such a big rig and the annular clearance is bigger so that the flow dynamics are optimized. Also in terms of geometry you are restricted by the size of the BOP at the top and the size of the perforation guns you need inside the last liner at the bottom.

"In HPHT wells you need higher resistance to pressure. But, we cannot really change the OD too much because of the limits of the BOP, flow dynamics and other physical limitations.

"Same for the wall thickness, if you increase it too much the bit for the next hole section does not fit anymore. That leaves the yield strength as the most obvious to increase if the pressure rating needs to be higher.

Henk Kramer, senior wells engineer, Nederlandse Aardolie Maatschappij (NAM)

"Then the H_2S becomes an issue. Statistically all HPHT wells will produce H_2S at some point in time. But that is not necessary always a problem. The issue is partial pressure H_2S. Meaning the: pH_2S = Total bottom hole pressure x fraction of H_2S present. So, if a HPHT field develops H_2S due to temperature at a later point in the wells life, the bottom hole pressure has gone down and you might be OK (or not).

"Chloride is also an issue, mainly in relation to temperature. Chlorides in combination with high temperature affect alloys, which is an issue for the production tubing, the tubing hanger and the casing hanger. And then what makes it really difficult is the combination of H_2S and high pressure.

"The problem is, finding materials with sufficient strengths suitable to accommodate all of these requirements can be difficult as these can be in conflict," he says.

Setting the grade

Some issues can be overcome by moving to proprietary steel grades from specific manufacturers for higher temperature uses, which can handle some H_2S, if the pH is high enough. But, defining the parameters in the drilling phase, when you are yet to define the pH, is difficult. In this case, a 'worst case' is often assumed, which is typically a value around pH 3.5.

Strengthening the pipe, without increasing the yield strength too much, usually results in increasing its thickness, which then introduces manufacturing issues as it becomes more difficult to have homogenous properties through the metal during quenching, Kramer says. "So we are getting to a limit where it is increasingly difficult to make metals with the right properties," Kramer says. "We have come a long way in HPHT wells but we still make steel the same way. We are getting to the edge of what we can do at current steel mills."

Pipe connections also have to be as strong as the pipe. Usually, seal face imperfections are sealed with an API modified dope, which is a mixture of oil with zinc, lead, and copper elements in it. The lead particles especially help to smooth out the imperfections, but importantly, it is stable at high temperatures. But, rather than conflicts in material specifications or manufacturing capability, this time regulations, in the Netherlands, and it is expected in the UK, are set to phase out use of lead offshore due to environmental concerns and rightly so, Kramer says. There has been a lot of work done to create a green dope, replacing lead with Teflon flakes and other alternatives, but they are limited by temperature.

Gaining confidence in the connections also has to be built. Historically, every company had its own standards for testing connections, Kramer says. "Only in 2002, the industry came up with standard procedure for testing connections," he says.

But since then, pressures and temperatures have increased and more confidence is needed in the connections.

An ISO standard for CAL IV testing has become more prescriptive and is pushing the connections very close to the edge of what is possible, and for HPHT requirements sometimes over the limit, which is a concern and often results in custom designed connections for a particular HPHT well, Kramer says.

Overall, "it's getting more and more extreme what we need" to work in uHPHT environments, Kramer says. OE

Deeper, hotter umbilicals

Materials technology is being challenged to its limits in the deepwater and high-temperature applications the oil industry is heading into. Technip's Alan Rutherford outlines work to make umbilicals fit for purpose in this area.

Thermoplastic hose. Photos from Technip.

The subsea umbilical market is evolving. The need for these products to go deeper and further continues and the requirement for higher temperature capable umbilicals is growing.

Umbilical technology is adapting to these new environments and continues to push the boundaries of the current technologies encompassed in the products, through new materials and innovation.

Market studies have shown a number of factors that drive elevated temperatures in umbilicals including; electrical power cores; hot fluid passing though tubes or hoses, solar radiation, umbilical burial adjacent to a hot pipeline, or a combination of these factors, especially in warmer water regions such as Asia Pacific, Africa and Middle East. The heat generated or experienced by an affected umbilical can lead to accepted temperature limits being exceeded for commonly used umbilical materials, resulting in de-rating of stress allowances or corrosion of metallic components, and mechanical degradation of polymers.

These factors leave umbilical manufacturers faced with many challenges; how do we design umbilicals to withstand these temperatures? Can these materials last for 25 years in service? Will new products be more cost efficient than current designs?

Facing these challenges led Technip Umbilicals to undertake several research and development initiatives on new technologies to ensure we can create products that are not only high quality but are also cost efficient for the current market.

Hose end fitting.

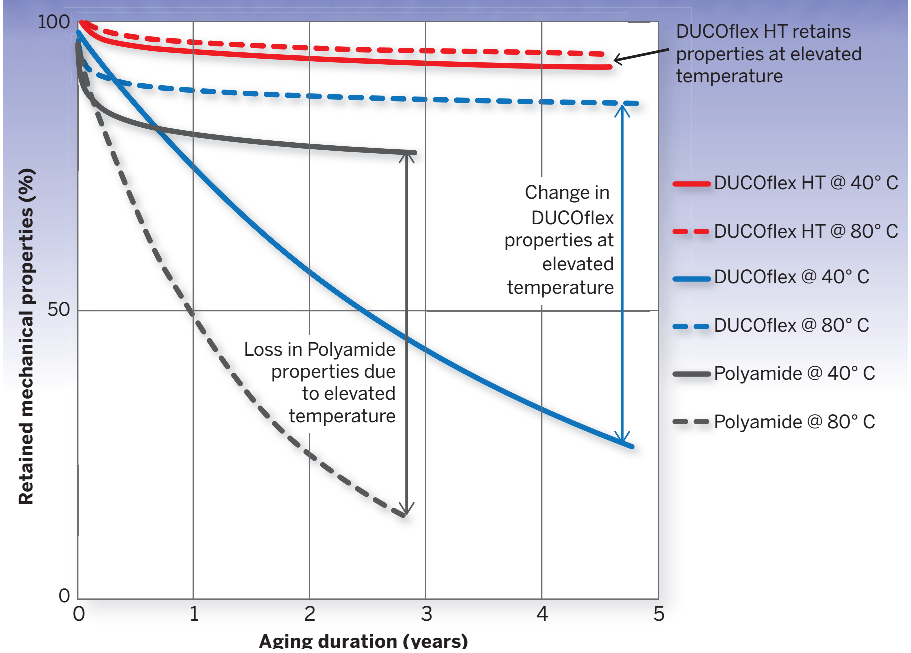


Figure 1 – Traditional hose liner materials vs. DUCOflex HT.

Overcoming challenges

Materials used within traditional thermoplastic umbilicals are able to cope in a wide range of applications and environments, including low-temperature and long-term continuous operations. However, using these materials in high-temperature environments, especially over long periods of time, can result in issues including; reduced collapse resistance due to material softening, reduced service life from degradation and difficultly in retaining the coupling on the end of the hose. In order to give the product long term viability, a fundamental change in all aspects of the hose design from liner material, reinforcement material, cover material and end fitting design was required.

To overcome the high temperature concerns in hose technology, Technip Umbilicals has developed a new thermoplastic hose design known as DUCOFlex HT (high temperature), creating a product which can operate continuously at temperatures from -40°C to +80°C and is capable of sustaining intermittent use at temperatures from -50°C to +100°C for longer periods of time, ensuring no degradation in performance.

Any new material must be more cost effective for future developments compared to the alternative; super duplex stainless steel tubes or coated tubes, which have a higher component and manufacturing cost compare to standard thermoplastic hose. Also, the additional benefits from easier termination and installation of thermoplastic umbilicals compared to steel tube umbilicals needs to be preserved to ensure the overall cost advantage is maintained.

Benefits of the technology

Technip Umbilicals patented the use of the polyethylene based liner technology DUCOflex in 1994, which gave significant performance improvements in terms of fluid permeation and collapse resistance. At the outset of this development, a range of materials were evaluated in order to determine the optimal material for high temperature environments, whilst maintaining the proven advantageous properties of DUCOflex.

In order to determine the long-term suitability of candidate materials, samples of Technip Umbilicals' traditional hose liner materials and the proposed new DUCOflex HT material were exposed to synthetic seawater at various temperatures for durations up to five years, and as can be seen in Figure 1. It is clear that the new DUCOflex HT hose material retains structural integrity during long term exposure to high temperatures, whereas the common alternatives, especially polyamide rapidly loose mechanical strength, resulting in significantly shorter life and reduced collapse resistance.

The increased temperature performance of the new DUCOflex HT hose also results in a more stable flexural modulus value as the temperature increases, this means that not only does the comparative collapse performance of the hose increase for a given temperature, it retains collapse performance over a significantly greater temperature band, meaning the useable water

Thermoplastic hose. Photos from Technip.

depth is significantly increased also.

The hose reinforcement design, both in terms of material and specific construction, has been modified to give enhanced long term performance at higher temperatures and has been tuned to give an optimal performance balance between working pressure rating and impulse fatigue. These modifications ensure the hose technical performance is improved, but critically remains fully ISO compliant, including a 4:1 factor of safety on burst pressure.

The metallic end fittings utilized with high-pressure umbilical hoses are typically the most challenging element in what is a very robust system. Therefore, in addition to the material changes to the hose construction, a new style of fitting needed to be developed to guarantee successful service at the higher temperatures. Elements of this fitting have been patented including a secondary lock nut mechanism to mitigate against loosening of the fitting during service. This fitting has been developed to allow connection with standard JIC or metric adaptors. However, as with traditional fitting designs, alternative joining arrangements can be provided to suit the clients' requirements including stub pipe designs for welded terminations to remove any threaded seal interface.

Going offshore

To reinforce the findings from research, a recent tender case study for high-temperature umbilicals focused on a 6km-long umbilical project located in 100-200 m water depth within Asia Pacific. The study highlighted that during planned maintenance the annulus lines were bled down via a vent line in the umbilical, allowing hot fluid to flow through and heat up the umbilical. During a typical operation, depending upon the water depth, constituency and temperature of the fluid, this could reduce the collapse resistance and limit the design life of a standard hose design. Traditionally this would have meant the hose was replaced with a stainless steel tube (lean duplex or super duplex), but this increases the cost and complexity of the umbilical. The steel tube is generally a longer lead time item, has higher bending stiffness, requires more time and cost to fit end terminations, is more challenging to install, has a finite fatigue life and is more costly especially if a corrosion protection coating (fusion bonded epoxy, for example) is required. By substituting steel tube with a new high temperature hose design this significantly increases the temperature and water depth performance without the costs and disadvantages of steel tube and enables the umbilical to remain fully thermoplastic with all of the associated benefits.

For this project study, a saving in the region of 10% was made by not replacing the affected hose with a super duplex stainless steel tube. Further savings could be realised through simpler termination hardware and less complex installation.

Taking umbilicals further

In the current market conditions, it is extremely important that companies adapt their products to fulfill market needs but with a strong focus on cost optimisation. As subsea market demands change, Technip Umbilicals are meeting these challenges with cost effective, industry leading products. **OE**

__Alan Rutherford__ has been working at Technip Umbilicals for over 15 years, during which time he has worked on various research and development projects including Super Duplex steel tube fatigue and long term ageing of materials. Rutherford is currently a principal engineer and lead of the team responsible for research and development of hose products and thermoplastic materials used within umbilicals.

Why the UKCS must make the most of HPHT development

By Morten Kelstrup, Managing Director, Maersk Oil UK

Anyone who doubts high-pressure, high-temperature (HPHT) developments are a different ball game to normal-pressure, normal-temperature (NPNT) offshore projects should look at a simple example of a 12in ball valve. For a conventional development, one of these valves would sit on top of an average office desk and still leave room for your PC. A 12in ball valve for HPHT conditions would fill up the office itself.

Maersk Oil, together with our co-venturers BP and JX Nippon, is developing the HPHT Culzean field. It's a hugely exciting project, and as the example illustrates, one with considerable engineering complexity. Culzean shows that large discoveries remain possible in the UK North Sea. The rub comes in the fact that, in a mature basin, where many of the large NPNT discoveries have already been made, finding significant new volumes means you have to be prepared for a range of technical challenges – in Culzean's case, the challenges of HPHT. It therefore stands to reason that such technically complex projects will increasingly drive change and innovation.

Handling the extreme pressures and temperatures in HPHT development safely calls for highly specialized equipment. That means a far greater cost than for a NPNT field. Our knowledge of the conditions and their effects on drilling and production has greatly increased. Developing the skills needed to make these fields a success is not only important for Maersk Oil, but also for the future of the North Sea. Together with West of Shetland and heavy oil, HPHT is believed to be one of the main areas of "running room" in terms of future UK North Sea development potential.

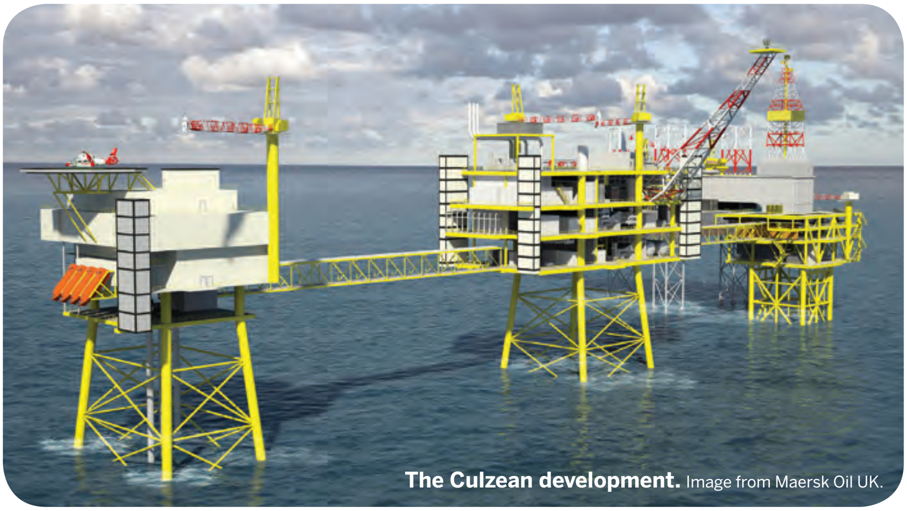
Developing an HPHT reservoir brings unique challenges. There are probably fewer than 100 HPHT wells currently producing around the world. It is, relatively speaking, a niche market. This makes the equipment necessary to complete these complex wells scarce, along with raising the costs, as equipment needs to be engineered to order; there are few "off the shelf" solutions. Upfront costs are also increased by the need to drill HPHT wells prior to the installation of the topsides in order to minimise depletion drilling. If we want to prolong the life of the UKCS we therefore have to be innovative to make more of these fields economic.

Strengthening the UK's HPHT skill set is essential. That isn't simply a message for operators. It also applies to partners in the supply chain who can export what they learn and develop far beyond the waves of the North Sea. What has been clear during the development of Culzean to date is that HPHT has a very distinct engineering community, defined by a willingness to share expertise and lessons learned. In an era when greater collaboration is so important, our experience has been tremendously positive, demonstrated by the willingness of other operators and experts to provide insight which has undoubtedly contributed to not only reducing the risk but also enhancing the engineering solutions of Culzean.

What we are doing with Culzean is working to build a truly 21st century installation, which keeps the safety of our people at its core. This has defined every part of the development plan, from detailed engineering, to drilling, to the layout of the topsides. We hope to deliver first production in 2019, and Maersk Oil and partners are committed to ensuring the wider engineering community shares in the lessons and learnings from the development of this project. OE

Together with West of Shetland and heavy oil, HPHT is believed to be one of the main areas of 'running room' in terms of future UK North Sea development potential.

– Morten Kelstrup



The Culzean development. Image from Maersk Oil UK.

Painting a moving picture

Heather Saucier investigates how microseismic monitoring is being used for monitoring field conditions in real time and helping to build better models.

One of the first times microseismic monitoring was used offshore was in the mid-1990s, when the deck of a platform in the Ekofisk Field in the North Sea began sinking – its surface slowly dropping toward sea level for unknown reasons.

Used mostly onshore at the time for cost reasons, microseismic sensing devices were adapted for the water, and over a period of months they detected a swarm of small earthquakes that occurred as hydrocarbons were pumped from the subsea reservoir. As a result, the reservoir began subsiding and the platform along with it.

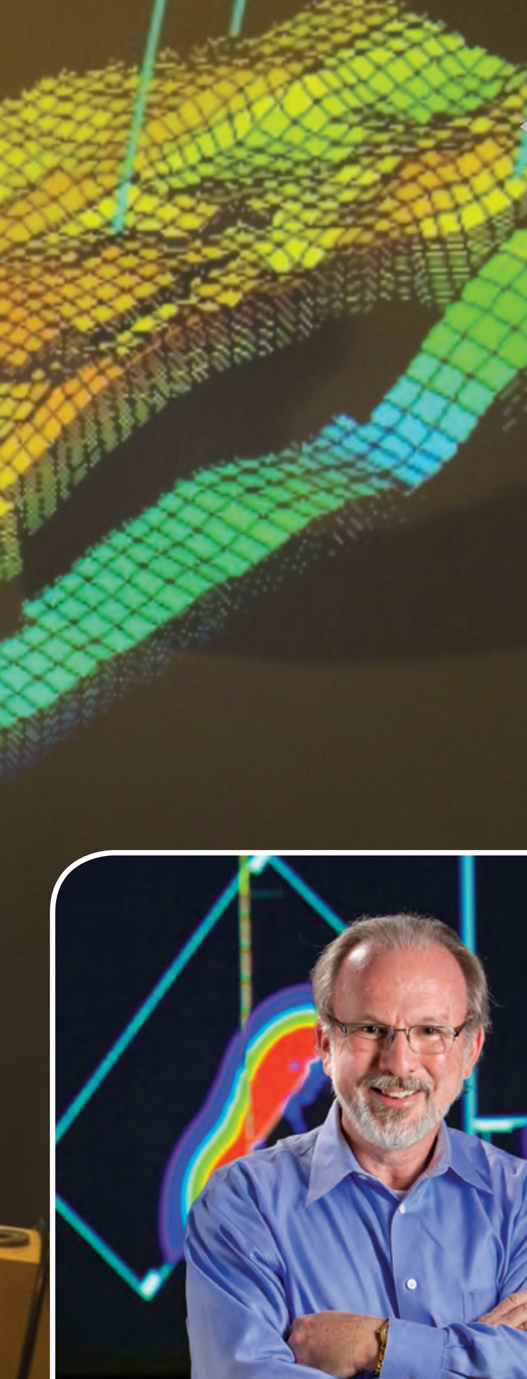
Today, microseismic monitoring is much more pervasive in the offshore industry – not only to diagnose problems after the fact, but to monitor reservoirs in real time for compaction and fluid movement.

"A lot of the reason microseismic monitoring was first developed for onshore use is because people wanted to see the results and appreciate what it means at a lower price point and lower risk before spending big bucks offshore," says Peter Duncan, co-chairman and founder of Houston-based MicroSeismic, Inc. "However, when used offshore, it does allow you to accelerate your response to whatever is going on in the subsurface."

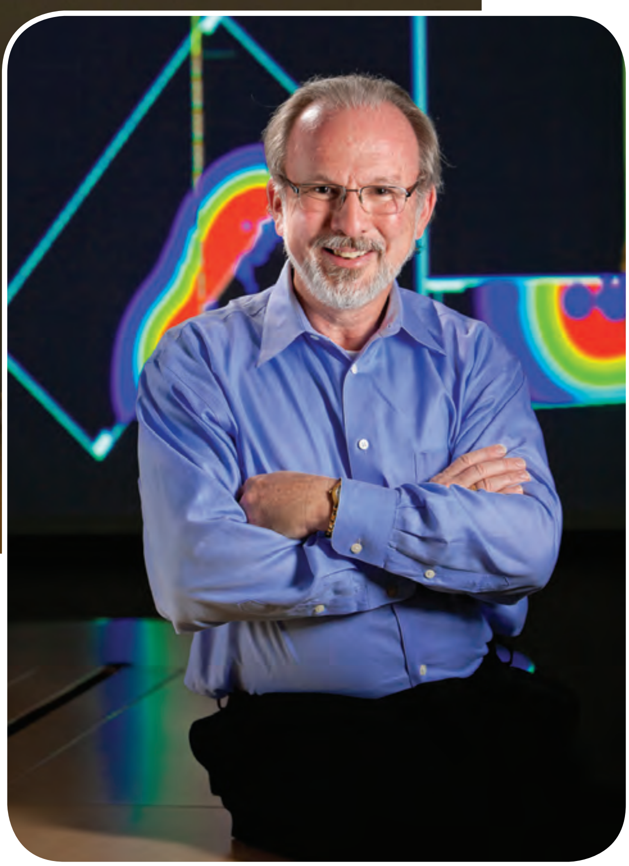
So, where there was once a dearth of data, the offshore is now facing what some are calling an "information explosion." In response, it's scurrying to build better models so that operators can understand in real time the goings-on in their reservoirs. As better models are built, operators can make decisions more quickly, ultimately realizing higher profits during an economic downturn.

A glimpse – by sound – into the earth

Realizing that microseismic monitoring can paint a moving picture of how a reservoir is responding during production



Landmark's 3D models can use reservoir monitoring to improve performance prediction. Image from Halliburton.



Peter Duncan, founder and co-chairman of MicroSeismic, Inc. Image from MicroSeismic.

and also predict how it may continue to respond – many operators are using the technology to maximize hydrocarbon recovery, Duncan says.

"When faults move during the course of production, they can offset a reservoir and form compartments. If hydrocarbons are not in contact with the production wells, this creates bypassed pay," he says, explaining that additional wells might be needed. "You want to stick a straw into it and suck the oil and gas out."

Many offshore reservoirs are highly compressible, adds Peter Flemings, professor of Geological Sciences at the Institute for Geophysics at University of Texas – Austin. "The reservoirs will compact and the grains will re-orient, resulting in significant displacements in the reservoir," he says.

A worst case scenario might be that well casings can be sheared off as the overlying cap rock is displaced, Flemings says. "You can lose a lot of money if you lose a well that way. Essentially, you have to plug the old well and sidetrack and go into the reservoir again," he says.

However, the most common consequence of compaction is a loss in production. "As compaction occurs, permeability declines. Flow is hampered and production becomes more difficult," Flemings says.

To help prevent such occurrences, microseismic monitoring has become a solution for many operators, especially those who already have set-ups for 3D and 4D seismic acquisition – whether they be geophones or fiber optic sensors in multiple wellbores, or large arrays spread out on the seafloor. For, in between 3D snapshots, geophysicists can use the same sensing equipment to passively monitor the behavior of the reservoir.

"Forward-looking"

Perhaps the most notable example of microseismic monitoring today can be found in the Jubarte Field, about 70km offshore the Brazilian state of Espírito Santo – a pre-salt field developed and produced by Petrobras and monitored by MicroSeismic in partnership with PGS.

One of the largest and deepest permanent fiber-optical sensing system in the world – with a 33km-long seabed streamer laid out over 9sq km and 1300m below sea level – Jubarte's offshore monitoring system has given Petrobras a serious nod by the industry.

"Petrobras was forward-looking and wanted to install a permanent monitoring system over the Jubarte field prior to development and production," Duncan says. "They also were forward thinking in the fact that they had an array in place and opted to monitor the reservoir during the downtime between the 3D surveys."

What the monitoring revealed was quite surprising. "We detected seismicity related to production when they turned on the field, but we did not see any events at the reservoir level," Duncan says. "However, events were taking place below the reservoir. They appeared to be related to motion along a deep fault that was perhaps reactivated by the production in the field."

As a result, Petrobras opted to continue the passive monitoring. "It's essential to understand what is happening. If this means that the reservoir is in communication with these faults, it's important to understand what that communication might mean," Duncan says. "Is more oil and gas going into the reservoir? Only time will tell."

Technology advancements

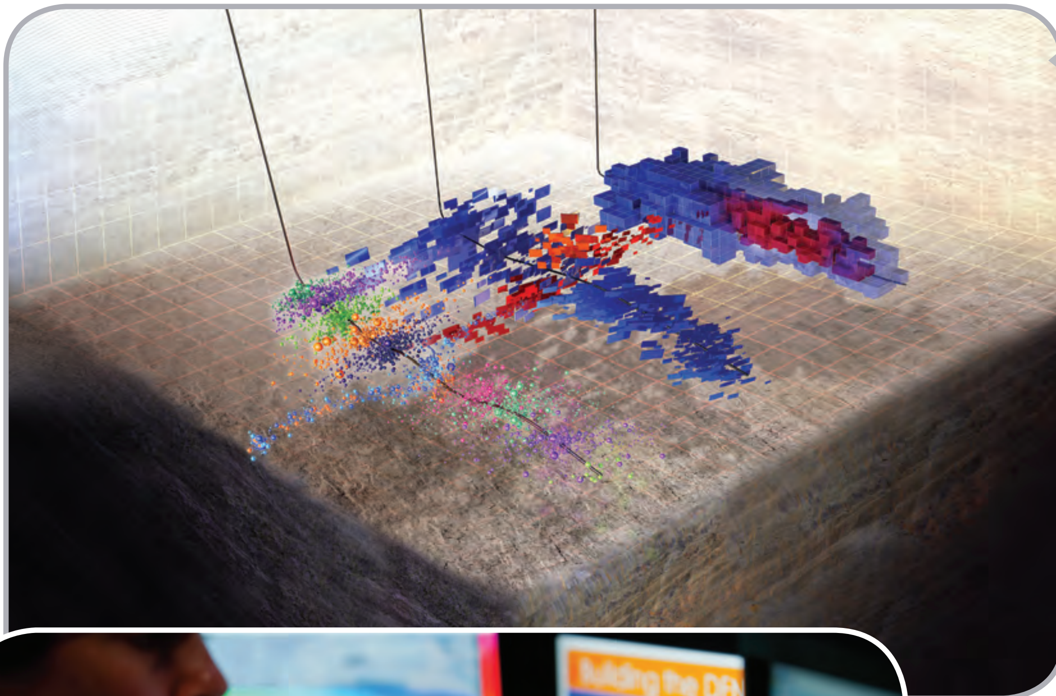
Microseismic monitoring has experienced quite an evolution over the last decade, technologically speaking. It began with the ability to detect the "hypocenter" of a seismic event's location – or where an event occurred in time and space, Duncan explains. "We knew that there was an event and that the earth moved, but not more than that," he says.

Yet, as more wellbores were equipped with sensing devices and as operators began to lay large sensing arrays on the bottom of the seafloor, more data was generated that could add more dimension to the seismic event.

"The nature of the sound – called the 'moment tensor' – we were recording told us the type of movement that was taking place in addition to its location," Duncan says.

If one side of a fault moved up and the other moved down, that is considered a dip slip. If one side moved to the right and the other to the left, this is considered a strike slip.

"The nature of the movement tells you about the local stress in the field at the time the rock broke," Duncan explains.



Microseismic monitoring shows how the reservoir responds to hydraulic fracturing in real time. Image from MicroSeismic.

Geoscientists analyze microseismic data in real time, enabling on-the-fly decisions for offshore reservoir stimulation. Image from MicroSeismic.

"The vertical and horizontal stresses in the rock combined with how the fluid interacts ultimately determines how the rocks break."

That geotechnical analysis can be fundamental to understanding how a reservoir will respond over time, say 10-15 years of production," Duncan adds.

Information explosion

It sounds so simple, yet geophysicists still have much to figure out when it comes to interpreting the "explosion of data" they are experiencing today from advanced monitoring, says Joe Lynch, director of Reservoir Management at Landmark, a business line of Halliburton.

Offshore has always been "data poor" in deepwater because it costs so much to get data, says Steven Crockett, senior product manager for Nexus Reservoir Simulation at Landmark. However, "now it is starting to experience the same data explosion that we've seen onshore," he says.

"The traditional means of data gathering was to test a tank with a dip stick every month, and that was the amount produced from a well," Lynch adds. "Now we are getting measurements on a second-by-second basis."

Crockett adds: "It is becoming more and more critical that models mimic what's going on in reality so that valid predictions can be made."

Building better models

To build better models, data processing and interpretation must be streamlined to achieve an accurate picture of a reservoir in a timeframe short enough to allow operators to optimize well locations and other completion challenges.

Information including the elastic properties of a rock, its brittleness and failure capability must be married with information about the stresses in a rock to predict how the rock will respond during production, Duncan says.

Yet, "the models we use today of how a rock will break are 2D. But, the Earth is not two dimensional, so groups are trying to develop 3D models," Duncan says.

One way to calibrate a model is through rock-breaking experiments in a lab. However, it is difficult to duplicate conditions of the Earth 10,000ft below its surface in a lab, he says. So, assumptions must be made.

"The best lab we have is the Earth itself," Duncan says. "And, the only way to see it is through microseismic monitoring, which is now producing the results that geomechanical engineers are trying to produce in a lab. Once we get better models, we can better understand how reservoirs will respond."

Furthermore, if the industry can more precisely measure where the hydrocarbons are coming from in a well, it can use that information to improve the quality of predictions that comes from the models, Lynch says.

"The better quality of models, the better quality of decisions that can come from those models at the end of the day," he says.

Looking into his "crystal ball," Lynch believes that the offshore geophysical industry will begin seeing trends in more automation, data management and predictive modeling to keep up with a heavy flow of information for operators who can't afford to lose a drop of oil in today's economic climate.

"What comes out needs to be actionable," he says. "The turn-around time needs to be fast." OE

Real-time seismic hazard monitoring with PRM

The recent integration of automated real-time seismic hazard detection is the latest development furthering the argument for permanent reservoir monitoring. Aaron Smith, of PGS, sheds light.

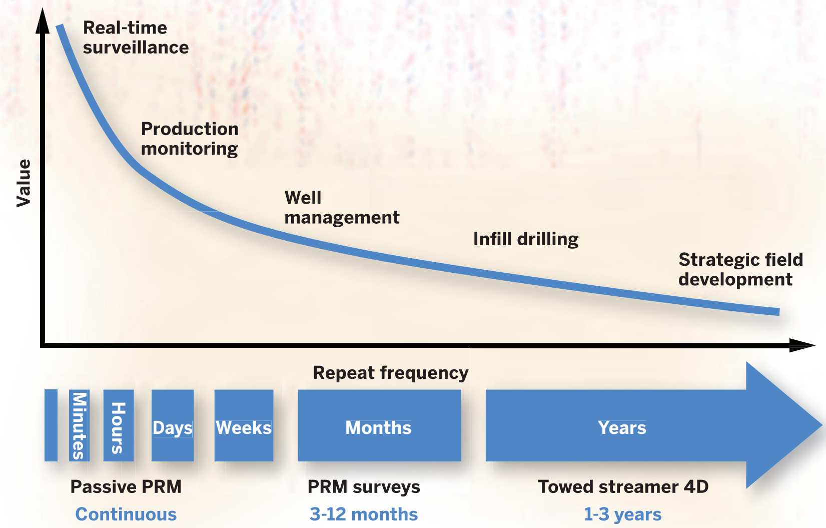


Fig. 1: Time scale of decision making in oilfield operations and associated relative value vs. different seismic monitoring techniques. The potential of utilizing passive monitoring for proactive production management and risk monitoring is so far largely untapped. Images from PGS.

Over the last two decades, time-lapse (4D) seismic has established itself as a valuable tool for offshore reservoir monitoring. Imaging production-induced changes has proven to increase the recovery rate and reduce uncertainty through a better understanding of the subsurface. But for operators who need to monitor reservoir conditions frequently, cost quickly becomes a factor.

Seismic receivers installed permanently on the seabed serve two purposes: significantly minimizing the cost of repeat seismic acquisitions and providing better image quality through higher repeatability and increased detectability. Commercial permanent reservoir monitoring (PRM) technology was first introduced in 2003 in the North Sea at Valhall, delivering significant value over the last decade (e.g., van Gestel et al., 2008), and has since steadily grown to a number of fields in the North Sea and Brazil. Recent examples include Ekofisk (Folstad et al., 2015), BC10 (Galaragga et al., 2015), and Jubarte (Thedy et al., 2015).

The ever-present push to maximize value from subsea assets has several operators looking to further leverage PRM technology beyond 3D acquisitions repeated at finite time intervals. Subsurface information at even shorter timescales can be extracted from passive seismic data, acquired continuously with PRM arrays. Rather than recording the reflected seismic energy produced from air-guns at surface, passive seismic records the energy produced directly from subsurface and seafloor activity in the absence of an artificial source. Already designed to continuously record active source data, PRM systems can easily record passive data as well. Recent developments in automation and remote operation have expanded PRM services into real-time passive event detection.

Seismic events of specific magnitude, location, or both can be independently recorded based on client-identified parameters in order to monitor and optimize reservoir production. Examples include the optimization of injection patterns for directing production flow, or the identification of potential production hazards such as reservoir zone breaches, pump cavitation, flow line slugging, or choke failures. As many incident investigations have shown, early warning of these production risks is paramount to their safe mitigation. It has long been recognized that environmental hazards can be more effectively mitigated by better seismic monitoring. In the US, mandatory offshore monitoring systems for risk mitigation have been proposed in new legislation as a response to the *Deepwater Horizon* incident. Norwegian authorities have started to mandate provisions for seismic monitoring systems as well in conjunction with sanctioning big field development plans such as Johan Sverdrup.

Microseismicity induced by pressure changes in the reservoir or stress changes in the overburden are the main diagnostic for deformation. Larger seismic events that could impose a risk to installations or compromise reservoir integrity are typically preceded by many much smaller seismic events. If captured with a sufficiently sensitive seismic monitoring array, such small events can give ample warning. Mitigation measures can then be planned ahead of time, e.g., in the form of changing production – or injection plans to alter the pressure distribution in the reservoir. At the same time, the distribution of microseismicity in time and space characterize preferred fluid pathways and drainage patterns. The latter information is complementary to time-lapse images and can be used to update the reservoir model. Other potential uses of passive data include monitoring overburden velocity changes through passive interferometry (e.g., de Ridder et al., 2014). This can help to detect surface breaches, e.g., of oil or re-injected cuttings at an early stage.

In order to be useful for reservoir management and risk mitigation, information from passive data needs to be available within minutes of occurrence, hence requiring real-time acquisition and analysis. By their very nature, cabled PRM systems are already capable of doing that, and in mature regions such as the North Sea, broadband onshore connections for real-time data transfer are already in place. In the age of constant connectivity and on-demand remote system monitoring, PRM systems then become just another component of the digital oilfield. Prior to reaching wellhead and valve tree sensors monitoring production infrastructure, PRM delivers in-situ information of reservoir changes before they reach the borehole.

Having real-time subsurface information at your fingertips for decision making quickly changes the value proposition of PRM systems. Passive monitoring not only makes much better use of the PRM capital investment, but also opens up new applications for subsurface information in production monitoring and hazard surveillance that provide significant value (Figure 1). The goal of all PRM data, both active source and passive, must be to get updates into the hands of reservoir and production teams as early as possible to maximize the impact of available actions.

Similar technology is regularly used onshore for real-time monitoring of frac-induced seismicity. The goal is to verify that a shale gas frac operation is not causing a fault activation that could potentially trigger a much larger event in populated areas. If an event is detected, it needs to be located, its magnitude determined, and warnings issued within seconds of occurrence. Recent upticks of seismicity in Oklahoma (mainly believed to be correlated with prolonged wastewater injection) led many US states to mandate such real-time monitoring and warning systems around shale gas operations.

The key to applying microseismic monitoring technology offshore for reservoir characterization and risk mitigation is achieving a sufficiently low detection threshold with the seismic array. Capturing many low magnitude events allows forecasting the risk of larger, potentially damaging production-induced events to occur.

A fully fiber optic PRM system offers performance and reliability advantages over alternative systems for both, 4D imaging, and real-time passive monitoring. Using passive, pressure-balanced fiber optic sensors provides broader sensor bandwidth, better vector fidelity, superior cross feed isolation, and lower noise floor. The avoidance of any in-sea electronic components leads to superior longevity that ensures the system will perform over the lifetime of the field. The first such PRM system in deep water was installed by PGS in 2012 in Petrobras' Jubarte field, located in Brazil's Campos basin. This pilot array consists of 712 4C sensors installed at 1300m water depth. It has since provided three annual active source surveys and multiple passive monitoring campaigns. The technology has resulted in several reservoir model updates and influenced well position changes. The impact of this seismic analysis and production planning has been estimated by Petrobras to yield EOR improvement of 4% in the area of PRM illumination.

Passive monitoring at Jubarte detected several hundred tiny microseismic events that could be used for subsurface characterization. The key to achieving this low detection threshold was analysis of all four sensor components which included shear wave arrivals on the horizontal components. Figure 2 shows a 4C receiver gather of an example microseismic event before and after rotation of the accelerometer component, which highlights the excellent data quality and vector fidelity.

Clouds of microseismic events could be located with high accuracy and align with faults visible in 3D seismic images. Results from the next scheduled repeat acquisition, approximately six months after microseismicity recordings, revealed 4D changes of the seismic image that seemed spatially correlated with the microseismic events. This highlights the significant value that can be provided by passive monitoring; detected microseismicity revealed dynamic subsurface activity when it actually occurred, in this case half a year earlier than it would have been detected relying solely on scheduled active seismic repeat surveys. This gives operators a significant advantage in understanding the subsurface and with reservoir planning. In addition, pinpointing the location of dynamic changes with two independent datasets (passive and active) reduces ambiguity related to the interpretation of sometimes weak 4D signatures in time-lapse images.

An additional uplift from real-time event detection with PRM systems is the ability to pair it with rapid seismic source mobilization. Active-source vessel(s) of opportunity can be mobilized on-demand when significant microseismic activity warrants immediate validation. Rapid high density time-lapse (4D) seismic can also be acquired over a subset of the field or array and fast-track processed in days rather than weeks. A target-oriented 4D over the microseismic area can then quickly help to characterize the dynamics of the region in question.

Once installed, PRM systems remain the fastest, most reliable, seismic imaging tool available proving that new efforts to reduce production risks continue being developed. OE

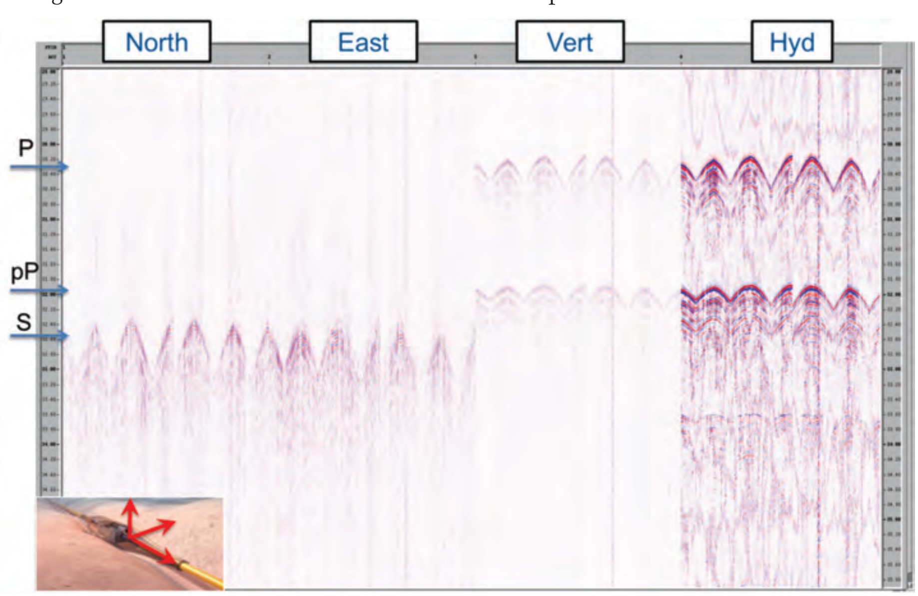


Fig. 2: Four-component gather of one microseismic event with good signal-to-noise ratio after component rotation. Note the clear separation of P- and S-arrivals between the horizontal and vertical components.

Gone fishing

Elaine Maslin speaks with OTC spotlight award winner Fishbones about the company's new Dreamliner technology aimed at increasing accuracy and efficiency in reservoir stimulation.

Fishbones' stimulation completion technology. Images from Fishbones.

The Norwegians like fish – it's in their blood, it's on their breakfast table and now it's even in their oilfield tool kit.

Well, almost. Stavanger-based Fishbones this summer performed the first field trial of its new second generation Fishbones stimulation-completion technology, called Dreamliner, offshore Norway. In 2014 and 2015, the first onshore trials of first generation Fishbones technology was performed in the US.

Fishbones is a multilateral stimulation technology, which uses small diameter titanium "needles," which are pushed out into the reservoir to increase exposure to the production zone. It is targeting conventional carbonates and tight sandstones, not shales, with two versions created to suit both of those environments. Fishbones for carbonates uses acid jetting and the Dreamliner tool for tight sandstones uses small turbines to spin drillbits on the ends of the needles to penetrate the reservoir.

Eirik Renli

Fishbones, led by former Baker Hughes' VP Eirik Renli, won an OTC Spotlight on Technology award earlier this year. Late October, Renli presented the technology to a Society of Petroleum Engineers event in Aberdeen.

"Fishbones is integrated into the liner and creates lateral channels like small wells lateral to the main wellbore," he explains. "Fishbones is the original jetting technology, with 12m-long needles and a nozzle at the front, which jets acid to push the needles out creating laterals. In tight sandstone, the jetting will not puncture the reservoir so we developed another product, Dreamliner, which uses drilling technology."

With the Fishbones acid jetting, 1m-long Fishbones subs, each with four needles, each secured by a pressure shear mechanism, are pre-installed onto the 11m long regular liner joints being used in the reservoir. It is run into the open hole as part of the lower completion. Standard liner hangers are set together with Fishbones' in house developed anchors, preventing lateral movement of the liner. A shoe closing mechanism is activated, acid is then pumped into the completion and as the flow increases the pressure across the needles shears the release mechanism, freeing the needles. The needles then press against the rock, jetting a pathway forward. Jetting continues until all needles are fully extended. The well is allowed to produce through the annulus and all the needle annuli.

With the Fishbones acid jetting, Fishbones has developed a "Fish Basket," which can run down the hole and clear out the remaining ends of the needles so tools can still be run down hole.

For the Dreamliner, each sub contains three needles, secured by a drill through mechanism. Each drill bit is driven by a turbine powered by the main flow through the liner. Again, they're installed onshore before being run in an open hole. It is design so anchors can be run in between the joints to avoid temperature elongation of the completion. When the string is in position, the liner hanger slips are set and the anchors are positioned then set by flowing into the well.

The flow is increased, which bursts the disc in the casing shoe and, as the flow increases, the turbines and needles reach the working rpm. Rotation releases the needles from the drill through bits and they then push into the reservoir, with some 25kilo force from the flow. Pressure responses during drilling indicate full extension of the needles. Cuttings powder is circulated out of the lateral and up the mother bore to surface. Once the needles are fully out, the liner hanger element is set sealing the annulus. The liner hanger setting tool is pulled and the upper completion is run and the well is allowed to produce. Production occurs in the annulus and all the needle annuli.

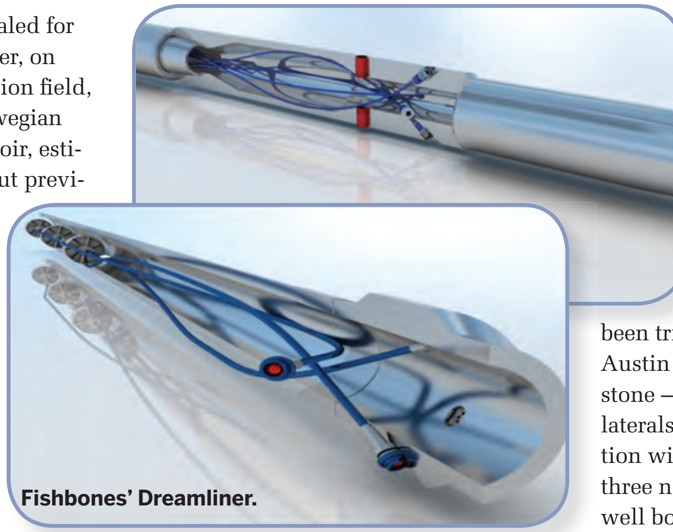
Fishbones is looking at ways to remove the turbines and needle ends from open hole so intervention operations and tooling can be run.

One of the benefits of using the needles, or Fishbones technology, instead of a traditional acid stimulation job is that there is more control over how far the stimulation goes into the reservoir, enabling the operator to avoid nearby gas or water zones, Renli says.

The technology, which has been in

development since 2009, was trialed for the first time offshore this summer, on Statoil's Smørbukk South Extension field, near the Asgard field in the Norwegian Sea. It is a tight sandstone reservoir, estimated to contain 16.5 MMboe, but previously deemed non-commercial due to the tight formation, low permeability and porosity ranging from "bricks to tiles," according to Statoil.

A dual-lateral production well with about 5200m reservoir exposure was drilled, targeting a 30m-thick oil bearing formation above a depleted gas reservoir. Horizontal barriers exist within the sand formation, limiting vertical flow. One of the laterals had the Dreamliner treatment. A 5½in Dreamliner completion with 48 fishbones subs, each with three needles, was installed in the 8½in open hole, creating 144 mini-laterals, spaced across selected zones targeted for stimulation.



Fishbones' Dreamliner.

In addition, Resman chemical tracers are being used – these are installed along the casing before it is run and are released according to pre-determined criteria, which means the operator can analyze the production, find the chemicals and know from which part of the well, and so reservoir, the production came from.

Renli says the operation appears to have been a success. Statoil has likewise hailed the project a success and said it would be looking where else it can use the technology. However, production data has not been revealed.

Prior to the Smørbukk South application, Fishbones had trialed the Fishbones system in an onshore coalbed methane well in Indonesia. The system installed correctly but issues with a downhole pump meant full results were not gained. Through a project supported by the Joint Chalk Research Group, consisting of Shell, BP, Total, Maersk Oil, Hess, Eni, Statoil, ConocoPhillips, Dong and the Danish North Sea Fund, the Fishbones jetting tool has also been trialed twice onshore Texas in hard Austin chalk and tight fractured limestone – both on horizontals. In the first, 60 laterals were created from a 4½in completion with 15 Fishbones subs, each with three needles, in a 6½in open hole mother well bore. While it was a low-producing well, at just a few barrels, production was increased by a factor of 4 to 5 times, over 30 days, says Fishbones. The firm is hoping to get another pilot well run through the joint research group.

Fishbones has also created a simulation tool which enables operators to input well data to see if their well would be suited to this technology.

Renli is pleased with the results so far and hopes production data from Smørbukk South will validate this new technology. OE

The North Sea gets steamy

Using steam to help increase oil recovery, particularly from heavy oil, is a well tried and tested technology, but not quite so offshore. Elaine Maslin looks at a bid to change that.

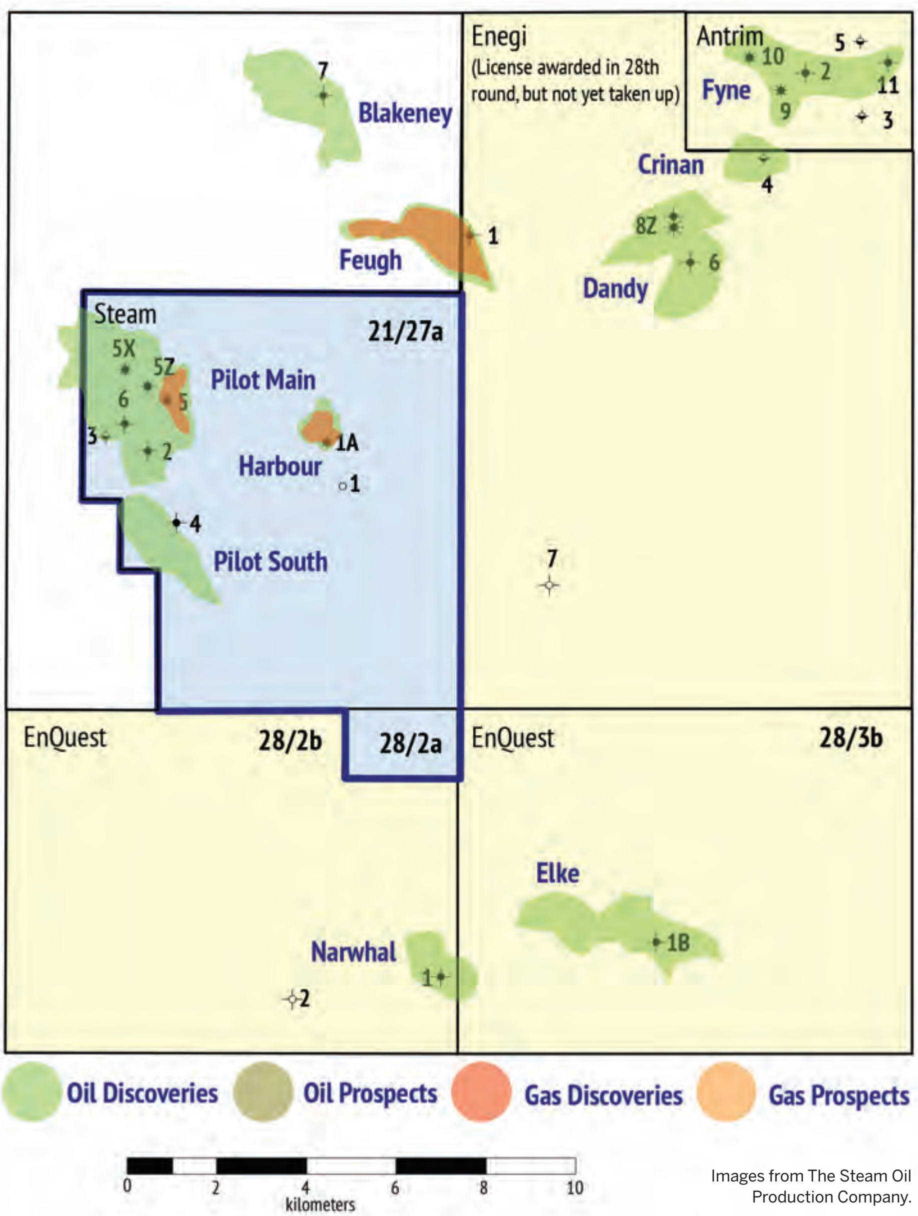
Steam flooding and cyclic steam injection have become tried and tested ways to increase oil recovery from oil wells, particularly heavy oil or in the tar sands where a special variant of steam injection known as steam assisted gravity drainage (SAGD), is used.

But, most of the efforts around steam flooding or cyclic steam injection, known as the Huff and Puff method, have been onshore.

Few, to date have tried to take the technology offshore, with the common assumption being that the density of wells required and the heat loss as injected steam travels down the well into reservoirs would be too great.

However, a UK company is now proposing to use steam flood for a field in the UK North Sea, which, if successful, could pave the way to develop other similar fields in the basin.

A steam flood Pilot



Images from The Steam Oil Production Company.

A Pilot reservoir

The Steam Oil Production Co. has its eyes on the Pilot field, in Promote License P2244 in Blocks 21/27a and 28/2a in the central North Sea, also containing the Pilot South and Harbour (both discovered by Fina in 1989 in excellent quality and permeability Tay Sandstone reservoir) fields and the Pilot Southeast prospect. The license has been appraised by Fina, Venture Production and then EnQuest.

Together, the three discovered fields contain 272 MMbbl proven plus probable oil in place at 12-18°API and 160-900cp reservoir viscosity, and around 3.5-6 Darcies permeability, according to Steam Oil. But, while a horizontal appraisal well in the most viscous region flowed at just under 2000 b/d from a 600-700m-long well, the recovery factor, with long horizontal wells and water injection, would be about 13%, leading to an uneconomic project.

Steam Oil thinks better rates could be achieved using steam flood. The company was set up in early 2014, aiming to initiate the first offshore steam flood in Europe.

Steam Oil founder and CEO Stephen Brown says steam injection in the North Sea actually isn't as unfeasible as it might sound.

"What attracted us to steam flood was the potential for higher recovery factors,"

Steam flood screening

from the Petroleum Engineering Handbook

Table 15.1—SEOR Project screening criteria[23]						Pilot
Reference	Ref. 18	Ref. 19	Ref. 20	Ref. 21	Ref. 22	
Depth, ft	<3000	<2500	<3000	>20	>400	2700'
Net thickness, *h*, ft	>20	>30	>30	>20	>10	30'–75'
Porosity, ϕ	>0.2	>0.3	>0.3		>0.2	0.34
Oil saturation, S_o		>0.5			>0.4	0.82
ϕ x S_o	>0.1		0.15–0.22	>0.0	>0.08	0.28
Oil gravity, API	10–34	8–40	12–15	<25	<36	13°–21°
Permeability, *k*, md	>250	>1000	>1000			3,500
Oil Viscosity, μ, cp	<15,000	200–1000	<1000	>20		100–1900
Transmissibility, hk/μ, md-ft/cp	>5	>50				>84
Initial pressure, psia	<1500					1228
Pattern size, acre		<10				≅ 5

18. Hayes, H.J. et al. 1984. Enhanced Oil Recovery. Washington, DC: National Petroleum Council, Industry and Advisory to the U.S. Department of the Interior.
19. Iyoho, A.W. 1978. Selecting Enhanced Oil Recovery Processes. World Oil (November): 61.
20. Ali, S.M.F. 1974. Current Status of Steam Injection As a Heavy Oil Recovery Method. J Can Pet Technol 13 (1). PETSOC-74-01-06.
21. Venkatesh, E.S., Venkatesh, V.E., and Menzie, D.E. 1998. PDS Data Base Aids Selection of EOR Method. Oil & Gas J. 82 (23): 63-66.
22. Chu, C. 1985. State-of-the-Art Review of Steamflood Field Projects. J Pet Technol 37 (10): 1887-1902. SPE-11733-PA.
23. Donaldson, A.B. and Donaldson, J.E. 1997. Dimensional Analysis of the Criteria for Steam Injection. Presented at the SPE Western Regional Meeting, Long Beach, California, 25-27 June 1997. SPE-38303-MS.

Source: The Steam Oil Production Co.

he says. "Chevron predicts 50-80% [recovery factor using steam flood]. Based on modelling, we are looking at around 60%, achieving about 150 MMbbl production from Pilot."

Steve Brown

Not so deep concerns

One of the key criteria for a steam flood project is depth. If a reservoir is too shallow, it could result in steam blowouts, but if it is too deep, heat loss in the well will reduce the quality of the steam too much. Going too deep will also, in combination with the steam, push the limits of completion components, Brown says. As a result, typically, the depth limit is given at around 3000ft, sometimes a little deeper, he says.

"At 3000ft, typically the reservoir is at 1300psi," Brown says. "At that pressure the steam temperature will be about 300°C or 600°F. There are a range of components available at that temperature, but you have to be very careful about selection. If you go to 5000ft, we are talking 340°C and you start to run out of completion components."

Greg Harding

But, there is some hope here, as the industry has been developing components for use on steam assisted gravity drainage (SAGD) wells in Alberta and for geothermal wells.

"When we first applied for the license we expected depth to be a big issue," Brown says. The firm expected they wouldn't get better than 50% steam quality, by the time it reached the reservoir, from 90% quality, 1500psi steam injected at the surface. But, after winning the license and undertaking heat loss modeling using a CMG Stars simulator, they received some welcome results.

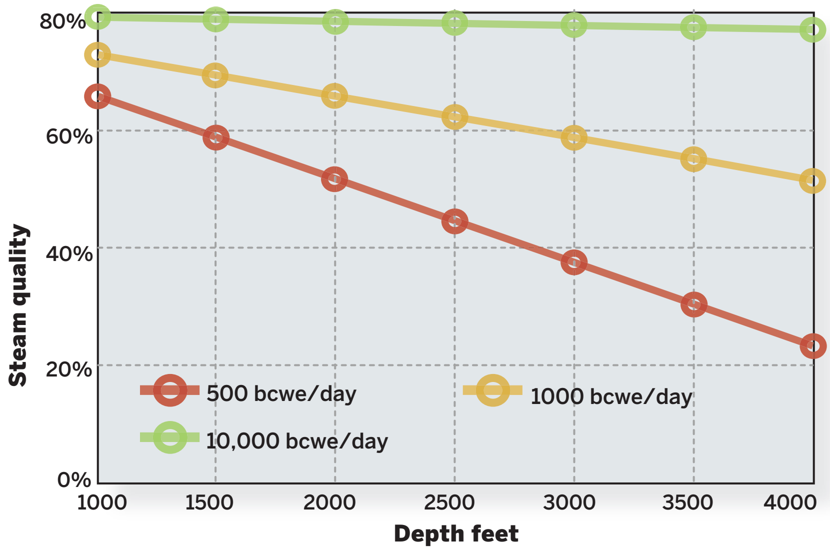
"The results were surprising," says Greg Harding, the firm's technical director. "We were only losing 5% of steam quality in the model. We thought there must be some mistake, so we looked around for other information on heat loss and realized a key factor is the rate at which steam is injected. Because the temperature of the steam is set by pressure, that keeps it constant. So you get a broadly consistent loss of heat, regardless of the rate you are injecting down the well."

The key to injecting at a high rate, and an enabler for this technology offshore, is being able to drill high density horizontal wells, Brown says. On Pilot, you would need 400 conventional wells. Using long horizontal wells, 100m apart, with alternating injection and production wells, you need 40, he says. "Those two things opened up this possibility."

Shopping for kit

The Steam Oil Production Co. has

Wellbore heat loss results



- Initial steam quality of 80%
- Initial steam quality of 80%
- At 500 bpd cwe steam quality is reduced to 23.3% at 4,000'
- At 1,000 bpd cwe steam quality is reduced to 51.5% at 4,000'
- Steam condensed is 285 bpd in each case
- So, at 10,000 bpd cwe steam quality would reduce by about 3%

Data for 500 and 1,000 bcwe/day cases, new advances and a historical review of insulated steam injection tubing - SPE-113981; 4,000' case calculated by extrapolation.

assessed what it would need in terms of topside equipment. They approached Cleaver-Brooks, a boiler manufacturer in the US which supplies SAGD projects in Canada, which suggested Steam Oil use an industrial water tube boiler, which can be quite compact. A 364,000lb/hr boiler, weighing 250-tonne, including ancillary equipment, could produce 25,000 b/d steam, Brown says. This would be instead of once-through steam generators typically used in tar sands heartland Alberta, Canada.

To produce the steam, water treatment facilities would also be needed, so Steam Oil went to Aquatech, which supplies mechanical vapor compression equipment for Mukhaizna heavy oil project in Oman, onshore. Aquatech advised Steam Oil to use reverse osmosis or similar, which is what BP is using on Clair Ridge for their fresh water, Brown says.

To get water pure enough – with solids content at less than 10ppm – they would need two passes through reverse osmosis and then using electrodeionization (EDI). This would mean lifting 300,000 b/d sea water, taking it from 35,000 ppm to c. 3000 ppm in the first stage, then 300 ppm in the second stage and to <10 ppm in the EDI, with 120,000 bbl water left. Once turned into steam and injected, the reservoir could then produce 80,000 b/d water and 35-40,000 b/d oil, Brown says. The water treatment equipment would weigh less than 200-tonne and adding both this and the steam generation equipment would only add 10-15% to the project's cost, Brown says. To house the equipment, and to enable intensive drilling and ability to access pumps in wells, etc., Steam Oil is looking at a fixed well head platform with dry trees.

Downhole tricks

Steam Oil is also looking to deploy autonomous inflow control valves (AICVs), to optimize the flood. "The 1500m-long wells will be 100m apart, pushing a pillow of steam across from one well to the other," Brown says. "But, it won't go in a straight line. It will wobble, with steam breakthrough in one area before another. To maximize recovery we want to shut off that break through point as soon as possible and it looks like the AICV is promising technology to do that." Steam Oil has been looking at Norwegian firm Inflow Control's AICVs, which were initially designed for to control gas coning in the Troll field offshore Norway.

Tried and semi-tested

While steam flood is certainly not common offshore, it has been tried. In Lake Maracaibo, Venezuela, steam boilers on barges inject steam on a Huff and Puff basis.

In Bohai Bay in China, CNOOC has also used Huff and Puff on a number of fields and they have also been mixing combustion products with the steam, to increase the recovery, Brown says.

Offshore Congo, Perenco has been using steam on the Emeraude field in 65m water depth. Total had a pilot in the 1980s, then Perenco built a platform and steam flooding started in a number of wells, but there seems to have been limited success, possibly due to the nature of the reservoir there, Brown says.

Brown says the Pilot field is very much like Shell's Schoonebeek field which stretches across the Dutch and German border, where it is operated by Wintershall and called Emlichheim. It is at a similar depth, 3500ft, and 3 Darcies permeability. Shell is using a similar well pattern as that planned for Pilot, but, at Schoonebeek the reservoir is more faulted and pressure depleted, Brown says.

Optimization

While Steam Oil has a broad plan in place, Brown says there could be optimizations, such as recycling the produced water and capturing heat from it, to reduce energy input.

"One of the things we want to do is make the process as efficient as possible," Brown says. "We are currently predicting we are going to have about 2.5-3 bbl of steam per barrel of oil extracted and the reality is that makes the economics work. But, if we can reduce that steam oil ratio it would improve the economics." The ratio is typically 2.5-5 on SAGD projects, he says.

There are also additional techniques, like those being tried in China and Canada, to add non-condensable gas, such as methane or nitrogen, to reduce the ratio to 1.5, or use a solvent like propane or butane, which would help mobilize the oil, with the added benefit of helping product transport downstream.

But, these optimizations are further down the process for Steam Oil. The young company with a big vision is now looking to work with partners to bring its idea to reality. We look forward to seeing the results. OE

Preparing for a successful **20K BOP campaign**

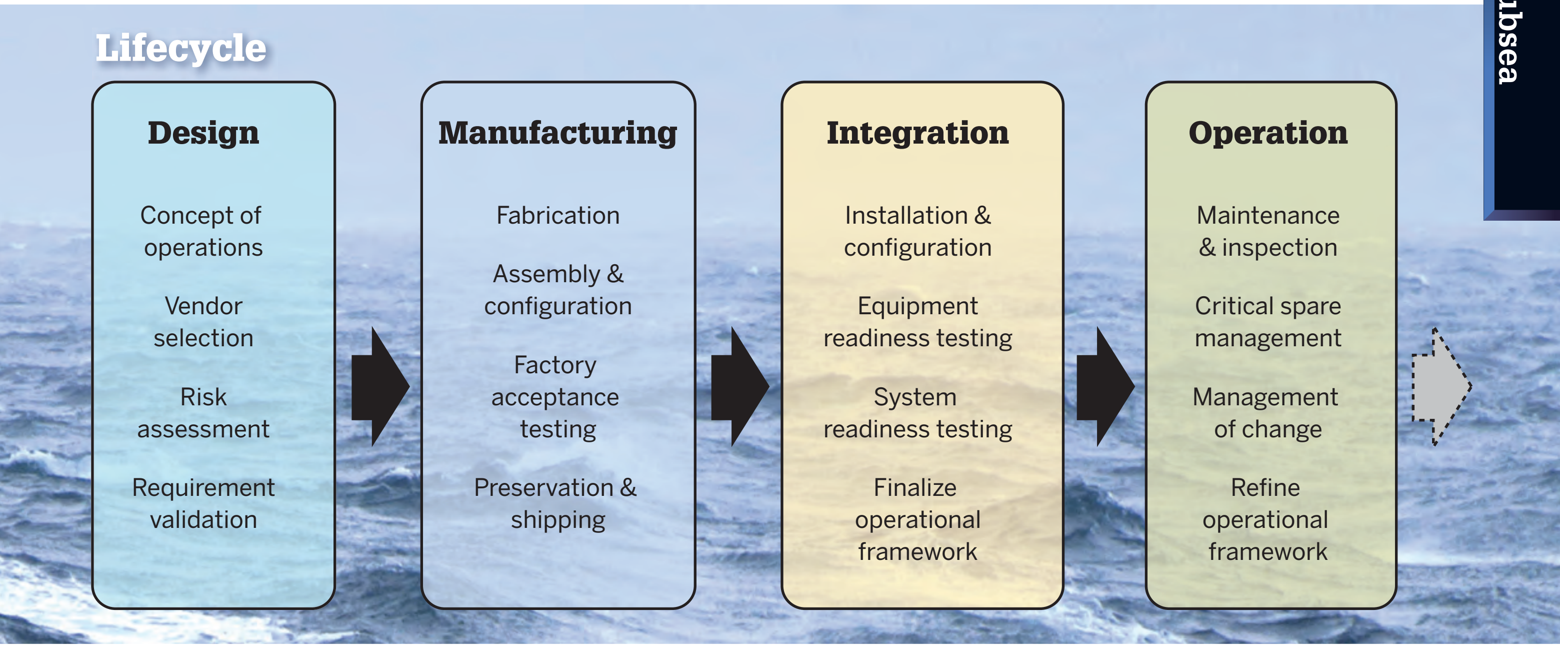
Athens Group's Daniel Marquez discusses why new 20K control systems require a new approach to specification, acquisition, operation and maintenance procedures.

As the industry moves closer to the deployment date for the first blowout preventers (BOPs) rated to withstand pressures of 20,000psi (20K), there is a notion that these new BOPs are "the same thing, just bigger." While technically correct, this vastly underestimates the true impact of this new technology on the entire drilling system. Ensuring successful drilling campaigns with 20K well control systems requires a new approach to specification, acquisition, operation and maintenance procedures.

A higher pressure rating requires thicker bodies and bigger rams, which lead to an increase in weight. OEMs may need to implement changes to material characteristics and design parameters to mitigate the weight increase, but the increase in size also impacts the BOP control system in terms of control fluid pressure, flow rate, and volumetric capacity. Additional sensors and software will be required to monitor and control the more complex system.

The design impact extends to other equipment on the rig that interfaces with the BOP, including the riser system, choke manifold, tensioners, riser handling, BOP handling, pressure testing equipment, and contingency systems such as capping stacks. The 20K BOP is now an integrated system of equipment, controls and supporting infrastructure. Ensuring this new system meets the safety and performance requirements of the drilling campaign requires a new approach

Acquisition, operations, and maintenance procedures used on current generation BOPs may not be appropriate for 20K BOPs. Photo by Daniel Marquez onboard a drillship operating in Angola.



20K BOP lifecycle.

to the processes that define the way equipment is operated and maintained, as well as the competencies and skills of individuals in charge of the equipment.

The BOP is essentially a "last layer of protection" safety system. Safety is a function of quality, and systems quality is provided through effective systems engineering. Therefore, the new paradigm must be rooted in well-established systems engineering principles. This means the industry must recast the traditional BOP lifecycle from an equipment acquisition focus to an integrated systems engineering focus.

Systems engineering is a comprehensive "people, plant and process" approach that aims to maximize the three fundamental quality attributes of reliability, availability, and maintainability (RAM) from a system rather than component level. Based on the American Petroleum Institute Standard 689 (International Standards Organization document 14224:2006) Collection and Exchange of Reliability and Maintenance Data for Equipment:

- **Reliability,** sometimes referred to as "dependability," measures the ability of a system to perform its intended function, within stated conditions, for a specified period of time. This is often seen stated as a probability, "the system is 99.9% reliable" or as mean time between failure (MTBF).
- **Availability,** sometimes referred to as "uptime," measures the ability of a system to be in a condition to perform its intended function at the instant in time when it is required. This is often seen stated as a percent uptime (inverse of non-productive time, or NPT).
- **Maintainability,** sometimes referred to as "serviceability," measures the ability of a system to be retained in, or restored to, a condition where it can perform its intended function. This is often seen stated as a mean time to repair (MTTR).

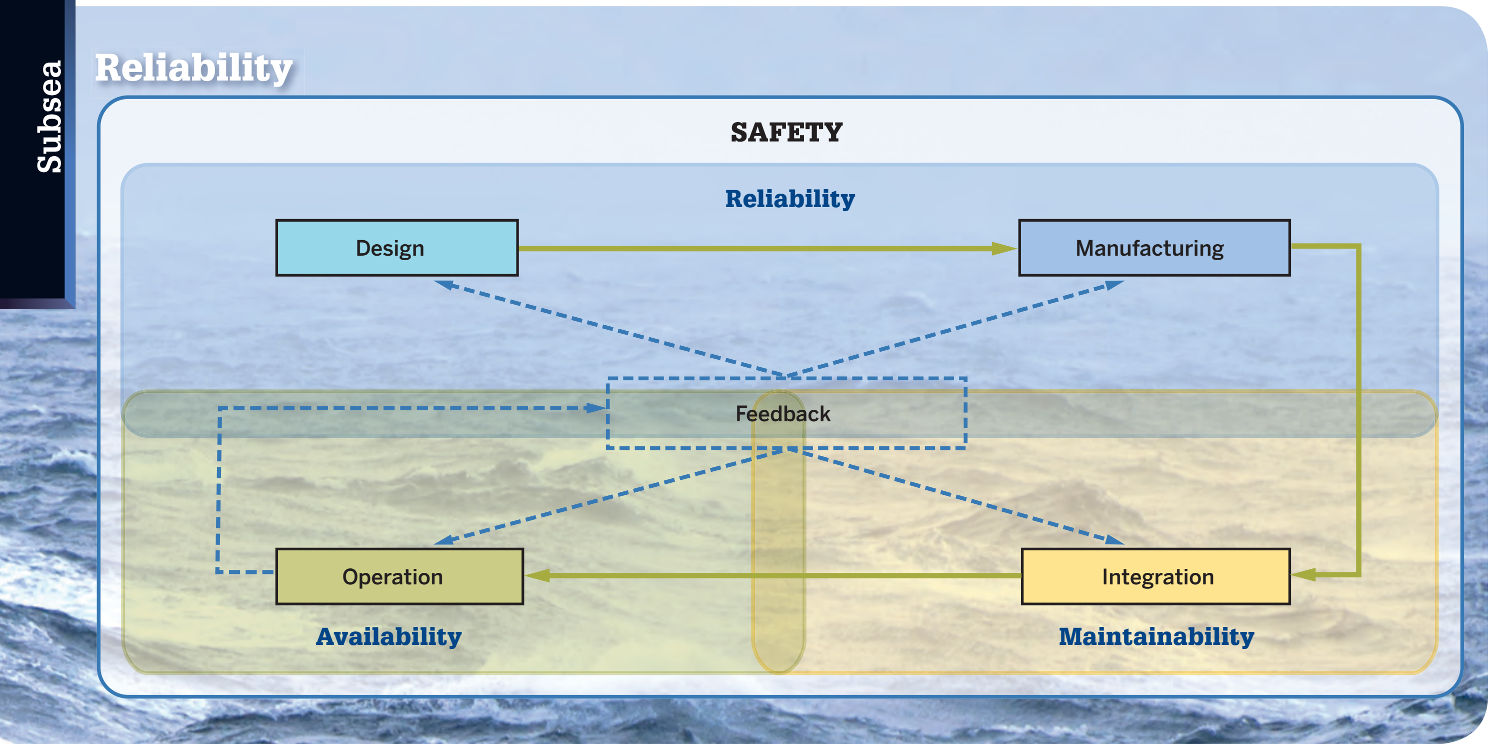
While the lifecycle of a 20K BOP may appear similar to existing BOP designs, there is one critical difference: there is no operational history from which to derive lessons learned and best practices. Reactive compliance based on proven-in-use experience is no longer sufficient to ensure operations meet performance and safety requirements. Therefore, it is imperative that the industry proactively establishes a systems-based framework that can articulate the impact of new technology, evaluate the inherent risks, and develop effective design, test, maintenance, and operation protocols.

There are several points on a systems engineering based lifecycle where we can positively impact the RAM of the 20K BOP system. To illustrate this, consider an example scenario.

During a systems engineering based factory acceptance test (FAT), the behavior of the ram locking mechanism is not consistent as the supply pressure is increased. At certain pressures, the ram fails to lock. A review of the design indicates that the problem is not unique to the unit under test, and that the problem could potentially exist in units already deployed to the field.

This scenario demonstrates how a systems engineering based approach can have a significant positive impact on system RAM. The fact that this particular defect was missed in prior development testing and FATs is a result of test plans that do not take a systems approach. In the example above, a requirement for the system to lock at all valid pressures was not adequately validated in the design, nor was it fully tested before the release of the mechanism to the field. A FAT which is based on systems engineering principles establishes direct traceable ties from requirement to test and ensures every requirement is validated in design and verified in test.

The example highlights another key element of the systems engineering approach, which is early and effective stakeholder involvement. A systems-based series of failure modes analysis, requirements verification and design validation milestones involving all stakeholders would have identified and eliminated the ambiguous locking pressure requirement well before delivery. Early stakeholder involvement in systems-based verification and validation milestones is the single most effective way to ensure RAM requirements will be met.



Reliability, availability, and maintainability in the 20K BOP lifecycle are all contributors to safety.

Once testing is complete and the equipment leaves the manufacturing facility, the ability to modify the system is limited. The FAT is essentially the last opportunity to identify issues in the design and increase the system reliability prior to delivery. Afterwards, the lifecycle switches focus from reliability to maintainability. The various levels of testing during the Integration stage of the lifecycle (i.e., pre-commissioning, commissioning, system integrated test, and acceptance) determine the inherited quality level of the design. It is also during this stage that preventive maintenance inspection test programs (PMITP), critical spare inventory management (CSIM), management of change (MOC), training and competency requirements, and other rig-specific processes are defined.

The collective operational framework for the rig is what defines the maintainability of the system. Competent resources, sufficient spares for the entire well control system and the necessary support infrastructure to move, position and access the BOP stack lead to minimum MTTR and high maintainability. Operational frameworks that do not consider the entire system including the maintainability of the extensive support infrastructure can render an otherwise functional BOP inoperable for long periods of time.

It should be no surprise now that we can have a positive impact on the availability of the system during the operation stage of the lifecycle. By this point we should already know the inherited reliability of the system and the specific processes we need to follow to ensure the system is available. It is during this stage that we also need to measure the system uptime and how long it takes to repair it when it fails. However, even if we track these metrics, implement the most comprehensive PMITP programs and contingency protocols, and keep our spare parts inventory stocked, we are limited to impacting only the availability and maintainability of the system; the reliability has not changed because the design has not changed.

The aforementioned lack of operational history makes communicating new lessons learned and operational metrics to the OEM critical for the continuous improvement of 20K BOP well control systems. It is the operational feedback that drives improvements in reliability of future designs. Stronger relationships with the OEM, especially during the operational phase, will be essential for the identification of recurring issues, development of engineering bulletins and product notifications, and help with troubleshooting and remediation strategies.

In summary, a more rigorous systems engineering approach to the specification, acquisition, operation and maintenance of 20K BOP well control systems can ensure safe and successful drilling campaigns despite the current lack of operational history from which to derive lessons learned and best practices. This new approach requires a higher level of cooperation and communication between the OEM and the end user throughout the entire system lifecycle to ensure end user requirements for system safety, quality and performance are verified through appropriate testing, and maintained through improved systems operational frameworks. A systems engineering approach to the specification, acquisition, operation and maintenance of 20K BOP well control systems can positively impact the safety and integrity of any drilling campaign. OE

Daniel Marquez *is a staff consultant at Athens Group with over nine years' experience, specializing in well control equipment design, risk assessment, verification, operation and maintenance. Marquez also develops tools and provides guidance on regulatory requirements, industry standards, rig quality management, and best practices. He holds a BS in engineering from Texas A&M University.*

Getting smart about corrosion

Jerry Lee speaks with Olga Koper, business lead for Energy at Battelle, to find out more about the company's corrosion resistant coating, which seeks to "heal" cracks in pipelines.

Battling corrosion is a constant struggle in the offshore environment, and effective inspection is made more difficult when the problems are too small to see. Addressing these issues, Battelle has developed a corrosion resistant coating using novel self-healing oligomer filled microcapsules, the Smart Corrosion Detector bead. The function of this technology is to "heal" cracks caused by corrosion and indicate the location of the issue.

OE: What is the technology behind the Smart Corrosion Detector bead?

Olga Koper

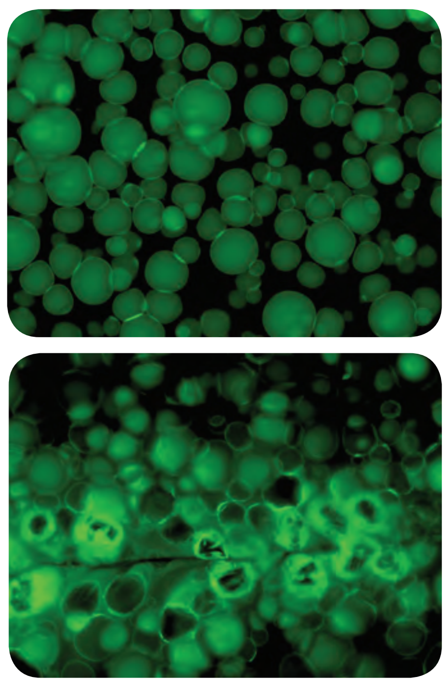
You have a capsule that is filled with an active material, which is then released upon a stimuli. It is an approach in which you are able to deliver an active material and control its release.

We use a particle forming polymerization approach to form a shell or capsule, 30-50 microns in size, which encapsulate the active material, a thermoplastic oligomer.

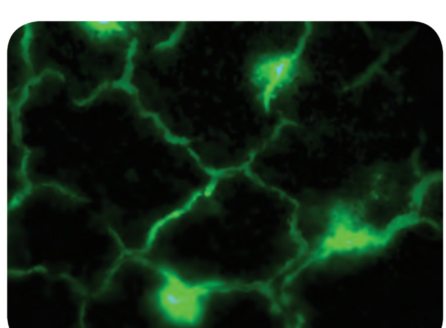
OE: What were some considerations during the development process?

There are several different factors that you have to take into consideration with this technology. You have to ensure that the active material is stable in the capsule, does not interact with your shell material and deactivate; the capsules must be correctly sized and dispersed in your coating or paint; that it has a life shelf ability; the capsules must have the right mechanical type of strength for the application so they are not damaged when mixing within the paint or coating; and there needs to be the right amount of capillary action to ensure the active material flows out when the capsule is broken and fills the crack.

These are interesting problems because there are so many variables that you have to get just right to get the desired properties.



"Smart beads," filled with chemicals that can fill cracks caused by pipeline corrosion, are added to a coating that is painted on the asset before it is deployed. Terahertz spectroscopy devices enable maintenance personnel to identify where the beads have burst and the pipe requires repairs. Images from Battelle.



The smart coating fluoresces in cracks under UV light.

OE: How does Smart Corrosion Detector bead work?

If you have a surface (aluminum) that starts corroding, trivalent ions (tri-aluminum) begin to form. These ions interact with the outside of the capsule and form a complex that causes the capsule to stretch to the point of breakage. The healing agent, a thermoplastic oligomer, flows out of the capsule and fills the crack that formed during corrosion. In addition, the complex fluoresces when exposed to UV light. So, not only is the crack healed, but you're able to see where the crack occur because it will be able to fluoresce.

OE: How is this a "smart" technology?

It is smart because the trigger is the corrosion by-product reacting with the shell of the capsule, stressing it to the point of breaking. The Smart Corrosion Detector bead mitigates corrosion and provides a visual indication, offering a multifunctional type of material that act when and where you want the action to occur.

OE: What applications are there for this technology?

This technology is focused on metals surfaces that are prone to corrosion. Since we are incorporating it into paints and coating, anywhere you can use coatings or paints you can add the capsules to have the self-healing application working. For offshore applications, we envision that it may have applications on pipelines, hardware, and equipment.

This is a flexible technology that can be used on many different equipment and surfaces. However, if the coating or paint is not able to withstand the environment, the capsules also will not be able to withstand it.

OE: What are the benefits of using the Smart Corrosion Detector bead?

Potentially, the beads can be incorporated into a paint or coating up to 10% by weight without any significant increase in the cost. Applying this paint or coating can elongate the life of your equipment so that you don't have to change the equipment that often or reapply the paint coating. We estimate that a 10% by weight inclusion of the beads would double the life of the paint or coating. Also, when the cracks are filled, some of the original strength may return, because you no longer have the cracks that are more pliable to breakage. **OE**

Bumper crop

Despite the massive cut backs the industry is facing, including cuts to exploration programs, drill bits continued to spin in 2015. Elaine Maslin reports.

Atwood Achiever. Photo from Atwood Oceanics.

2015 has been a drawn-out tale of cost cutting, capex reduction, exploration cutbacks, retreats back to heart lands and pulling back from risky frontiers.

But you wouldn't tell if you looked at the year's exploration results. Deepwater ranks high, as do new plays and frontier areas and it's largely the majors leading the charge.

"The simplest way of explaining this is we are yet to see the exploration outcomes from the new strategies," says Andrew Latham, vice president of exploration research at Wood Mackenzie. However, while companies are adapting, he thinks there will be players willing to test these types of new resources, noting that the top 10 discoveries for 2015 so far are very much in the hands of the majors.

Overall, the average discovery size has been about 700 MMbbl, slightly up on recent years, with gas accounting for about 80% of it. But, the results are somewhat skewed by the top two finds, Zhor and Ahmeyim (previously known as Tortue), off Egypt and Mauritania, respectively.

Top 10 discoveries for 2015

Discovery	Country	Basin	Well operator	Vols. discovered (MMboe)
Zohr	Egypt	Nile Delta	Eni	3960
Ahmeyim	Mauritania	Senegal - Bove	Kosmos	1408
Sicily	US (GoM Deepwater)	West Gulf Coast Tertiary	Chevron	300
Katambi	Angola	Kwanza	BP	276
Liza	Guyana	Guyana	ExxonMobil	250
Atoll	Egypt	Nile Delta	BP	229
Isosceles	Australia	North Carnarvon	Chevron	222
Kronos	Colombia	Sinu	Anadarko	176
Mdalasini	Tanzania	Tanzanian Coastal	Statoil	172
Zebedee	Falklands/ Malvinas Islands	North Falkland	Premier	106

Data from Wood Mackenzie, covers Q1-Q3 end 2015.

Zohr

Zohr, discovered by Eni, using the *Saipem 10,000* drillship, contains some 3960 MMboe, according to Wood Mackenzie, or 30 Tcf/5.5 Billion boe potential reserves, according to IHS. It is a massive find and opens a new play, the Miocene reef play. It has the same petroleum system as Israel's giant Leviathan, but a new reservoir, the Miocene reef, Latham says.

"Not only is Zohr very large, assuming it is appraised well, it is clearly commercial and that commerciality of new resources has been an issue in recent years," he says. "If it does pan out to be commercial, we will have a higher average proportion of commercial reserves than resources booked this year," Latham notes, adding that this is something that has been lacking in recent years.

It is also a significant find in terms of gas markets, particularly for Egypt. "All bets are now off in the Eastern Mediterranean in terms of the gas market," Latham says.

For some time, Egypt, which has LNG export facilities, has been reversing pipelines to bring gas into the country, because demand has outstripped local supply. Zohr could change the game, which had seen Egypt eying importing gas from Cyprus and Egypt.

"And then the open question is 'how many more Zohr-like prospects are there either in Egypt, Israel or Cyprus," Latham adds.

The *Saipem 10,000* drillship.
Photo from Saipem.

Ahmeyim

Ahmeyim is another frontier play, however, it is not as close to markets as Zohr. Ahmeyim was discovered by Kosmos Energy, using the *Atwood Achiever* drillship, and labelled the largest Atlantic Margin discovery of 2015. It could have been an oil or has find, Latham says.

Like Zohr, it also opened a new petroleum system, the outboard, large-scale Cretaceous petroleum system across Mauritania-Senegal, and could hold some 15 Tcf, according to Kosmos. Exploration and appraisal is set to continue into 2016 on Ahmeyim, Kosmos says.

Liza

Liza might not be top of the rankings, however, it is a significant find for Guyana. It is the first oil discovery in Guyana and is also another play opener and ExxonMobil is reported to be fast-tracking a project to unlock its reserves.

Liza could also be bigger than the figures so far released, Latham says. "I wouldn't be surprised if it turns out to be significantly bigger than 250 MMboe," he adds. Guyana's minister of governance has in fact suggested the field could contain 700 MMbbl reserves.

According to Matthew Jurecky from GolbalData, Liza's commercial success could redefine the Equatorial basin as a global deepwater production player.

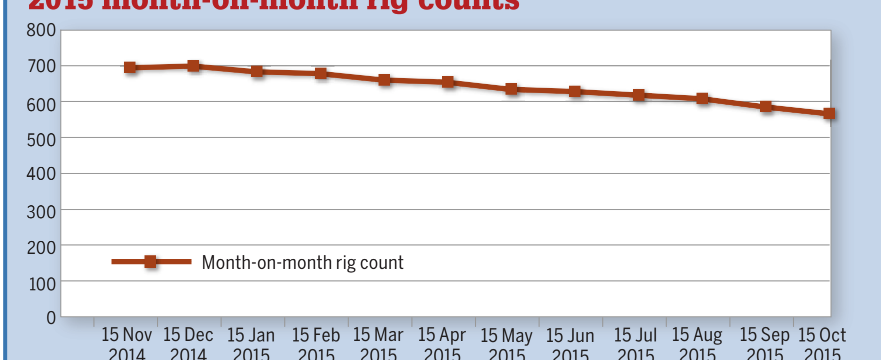
Lira

Missing from our top 10 list is the recent reported 30 Bcm or 1 Tcf of gas found in the Lira discovery in the Black Sea, offshore Romania, in October.

It is the second announced discovery from the deepwater Black Sea from only three exploration wells. Cumulative resources of the two discoveries is expected to be 3-4 Tcf, Wood Mackenzie says. There are a further four exploration wells which have been drilled and completed by ExxonMobil, which have yet to have their results released.

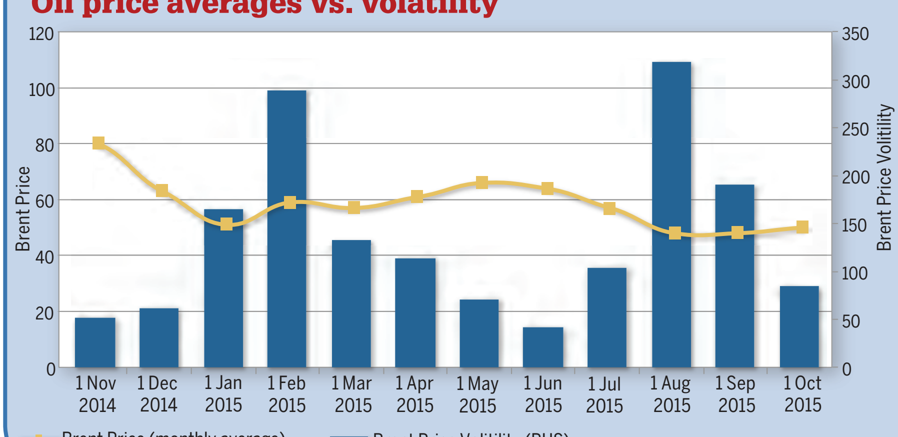
Lira was drilled in 700m water depth using the semisubmersible drilling rig *Transocean Development Driller II*. The well was temporarily abandoned for further evaluation. Lukoil plans to drill an exploration well in 2016 and reprocess the seismic data. OE

2015 month-on-month rig counts

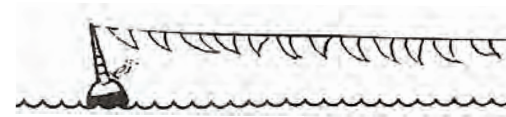


Data from Infield Systems

Oil price averages vs. volatility



Data from Infield Systems



This is 40

40 years of OE

Respect the men with new ideas

by Edward Heerema, President, Heerema Holding Company.

"The last ten years have shown very dramatic developments in our part of the business. I sincerely hope that the next ten years will respect those men who come with new ideas, allowing the industry to come on an even higher plane.

I am convinced *Offshore Engineer* will, as in its first ten years, be around as one of the prime media who give much attention to those new ideas."

When OE turned 10 in 1985, we invited the leading figures in the offshore industry to reflect on highlights from the previous decade. Now that we're older and wiser, we decided to yet again reach out to some familiar faces to not only reflect on the past, but to ponder the challenges yet to come.

Forty years on: what we have learned

By Professor Alex Kemp, University of Aberdeen

First oil production in the UK Continental Shelf (UKCS) dated from 1975, when the Argyll field, operated by Hamilton Brothers, came on stream. Forty years later, the same field was reopened with a new name (Alma) and a new operator (EnQuest). In the interim the field has been decommissioned not once, but twice, and the current licensees believe that Alma can produce for a significant number of years.

Boom and bust – lessons learnt

By John Westwood, Chairman of Douglas-Westwood

In January 1985 my *Offshore Engineer* piece headline read "the boom and bust cycle continues." The subject was the impact of the ROV on underwater contracting. Today, we are experiencing the impact of another technology disrupter – successful fracking of US shales has within a five-year period unleashed 4.4 MMbo/d onto the world market, leading to a collapse in oil prices. Of course it's not just about technology but involves another key element – people prepared to think differently and take the associated financial risk.

But to be successful, detailed

Offshore Engineer's 40 years

By Edward Heerema, President, Allseas

During 40 years of *Offshore Engineer* magazine, since its launch in 1975, we have seen the vast development of the offshore industry with the emergence of huge oil and gas drilling and production platforms and pipelines, and the equipment to make this possible. The pace at which technical developments followed each other has been striking; it would have seemed that such a pace could not be maintained, but it was. In that sense our industry maintained its momentum.

Heerema

But the industry did change in many ways. The industry has become more formal; responsibilities of individuals have reduced in favor of senior management decision making and presumed financial prudence. Legalistic contract management has made project execution processes more difficult and slower. But in an industry that has outgrown its pioneering stages, this is quite understandable. Also the increased complexity of techniques and projects has made the processes slower and more difficult.

The competitive game, more so than 40 years ago, drives all participants to greater ingenuity in order to increase efficiency.

In many ways, private companies have led the way in development of new technology; this has always been the case, but in the past 40 years has gained wider respect. The typically long-term view of the family business has stimulated ingenuity and dedication.

Safety has become a key driver in operations, so that – despite a few major mishaps – our industry is very safe. Particularly for the man on the job, safety precautions have significantly increased.

Over the last 40 years, *Offshore Engineer* has always highlighted technical developments in our industry, and this makes every issue worthwhile reading. ▪

OFFSHORE ENGINEER

This story illustrates the very substantial technological advances which have taken place in the UKCS over the period, and which are gradually increasing the recovery factor. A key example is horizontal drilling, which, when combined with 3D seismic, has greatly increased productivity in the industry.


Kemp

The year 1975 also saw first oil from the giant Forties field. In this case, the estimated recoverable reserves have been increased many times since then and the cessation of production date continues to be extended. Technological progress, cost reductions and high operational efficiency combine to generate continued substantial output. Both examples illustrate the importance of technological advances and operational efficiency for the health of the industry.

The 40 period has witnessed several dramatic changes to the operating environment, with periods of steeply rising oil prices being followed by equally dramatic price collapses. In many ways the current period of low prices compares with the 1986-87 period. If this parallel is correct the ensuing recovery will be gradual.

Government policies, particularly in the taxation area, have to adapt to the dramatic changes in oil prices, investment and operating costs, and prospectivity. The fully profit-related system which exists now is conceptually more appropriate than that pertaining in 1975. But, as has happened many times over the years, the adaptations have come with delays in their execution. ■

knowledge of the market for the technology and the client needs is also essential. This was also the case when we started the world's first commercially successful ROV operator in 1979 and eventually achieved a 16 times gain in cost-effectiveness, and in doing so wiped out the manned submersible business.


Westwood

Fast forward to the years 2000 to 2013 when oil and gas expenditure grew by 237%, but oil and gas production by only 24%. To compete with the Middle East producers demands we slash costs and one opportunity lies in 'industrialization' – giving developers the ability to select from a range of mass produced standard modules to suit their offshore field characteristics.

So what can we say about the future? Oil and gas is today a 155 MMboe/d industry with major long-term prospects – the world needs increasing supplies of oil and gas. Douglas-Westwood estimate that on-and-offshore, some 448,000 new development wells will be needed from 2015-21. Huge opportunities exist for both game-changing innovation and also more corporate consolidation – the supply chain is still far too fragmented to operate at maximum efficiency and ride the industry cycles.

And what of oil prices? The underlying pressures are upwards and furthermore the geopolitical wild cards are always in play – one significant incident in Saudi and US$100 oil will seem cheap! ■


OFFSHORE ENGINEER

continued from page 46

many fields still to be discovered, many discoveries still to be developed, and more scope than ever before for imaginative and cost effective solutions.

Among other future developments, I foresee increasing use of compliant systems and continuing emphasis on subsea systems, but must express concern at the apparent trend towards over-sophisticated design, leading towards tighter specifications, fabrication difficulties and hence increased costs.

I hope that the expertise that has been developed in Britain can be enhanced and consolidated, through better co-operation between the various parties concerned, to corporate and national benefit.

When *Offshore Engineer* first appeared on the scene, I held a BP London-based appointment as manager, projects (development and construction) for Abu Dhabi Marine Areas. Over the immediately preceeding three years I had responsibility for BP's North Sea operations as manager, UK exploration and production.

Though my direct involvement in and responsibility for North Sea operations came to an end in 1974, my interest and involvement in offshore activities has continued unabated since. It is hard to keep track of fast moving developments through occasional personal contacts, and this is where I have found *Offshore Engineer* invaluable. I regard it as an authoritative source, with apparently well-informed comment and detail on topical subjects. Long may it continue in this manner. ❜

Pioneering underwriting also needed

by John Wallace, Director, Sedgwick Offshore Resources.

❛Ten years ago the largest amount we could insure on a platform, say Forties or Frigg, was $250 million.

Many a time since then we have had to dig deep in the London market and all over the world to get ever more cover as values increased.

I remember one occasion, just before the tow out of Statfjord B, when I was pushing an underwriter to take a major share . . . "Why should I risk everything I've got when the oil company is worth so much more than me?" the underwriter asked. "Because oil companies are in the risk business like you — they now need you to really push the boat out, and share the risk!" I replied.

Just as oil companies and contractors have moved into unknown areas the insurance community has stood right along side them. Pioneering technology needs pioneering underwriting. ❜

Underwater service — the boom and bust cycle continues

by **John Westwood,** *Managing Director, Smith Rea Energy Analysts (from 7 January); formerly Marketing Director, BUE SubSea.*

❛In the past ten years I've witnessed the rise of two new technologies, and if nothing else, this decade proved to me that the underwater service contractors are continually living in a boom or bust environment, of their own making.

In 1975 I was working as a project engineer with Vickers Oceanics, the company having recently proved that the manned submersible was far more effective than the diver for running pipelines, and I was engaged in engineering the submersibles to act as survey vehicles.

My conclusion that the manned submersible market was on a hiding to nothing dawned slowly. 'We've investigated rovs — there's no way you'll ever get them to work' was the reaction to my resignation.

1977 was the dawn of the age of the rov. My new company Sub Sea Surveys made a profit by offering pipeline inspection by *Consub 2* at one half the day rate of manned submersibles.

The North Sea construction boom fell away.

The 1977 market for manned subs was £9 million, giving work for nine vehicles — 22 were available for North Sea work. The rov ascended over the funeral rites of the manned submersible companies. £60 million was consumed by half a dozen manned sub companies in less years. There would have been greater contribution to UK energy by burning all this money!

So the cycle continues. Today rovs are in a state of 2:1 oversupply with the added complication that their major owners, the diving companies, are in the midst of serious financial problems. However, the promised construction boom of late '85 onwards offers hope of profits, but perhaps to more educated contractors.

The text book may be wrong — market share does not always equal profit share. There must be market attacks available to the underwater contractors other than kamikaze. ❜

An industry-wide success story

by Mick Duckett, Managing Director, Atkins Oil & Gas Engineering.

❛The offshore oil industry began for me in July 1973 when I helped to start a new company in Scotland, set up to build modules for the UKCS. I soon began to appreciate the differences between the offshore business and my previous fascination for the management of the design and construction of process plants. I therefore became an avid reader of the offshore technical press which included *Offshore Engineer*. In the intervening time the technical press for 'our industry' has changed, some have gone, some have arrived and others have changed shape or format. One that I am still reading is *Offshore Engineer* since I am pleased to say I still have my part to play in today's offshore developments.

Quite a few words have been read and said, since the early days, about how to extract oil and gas from the bottom of the North Sea. The industry, oil company to humble supplier, have played a part in a success story in which we can all be proud.

Well done to *Offshore Engineer* and its editorial and production staff, for its first 10 years and continued success in the future. ❜

JANUARY 1986

Underwater service — the boom and bust cycle continues

by **John Westwood,** *Managing Director, Smith Rea Energy Analysts (from 7 January); formerly Marketing Director, BUE SubSea.*

❛In the past ten years I've witnessed the rise of two new technologies, and if nothing else, this decade proved to me that the underwater service contractors are continually living in a boom or bust environment, of their own making.

In 1975 I was working as a project engineer with Vickers Oceanics, the company having recently proved that the manned submersible was far more effective than the diver for running pipelines, and I was engaged in engineering the submersibles to act as survey vehicles.

My conclusion that the manned submersible market was on a hiding to nothing dawned slowly. 'We've investigated rovs — there's no way you'll ever get them to work' was the reaction to my resignation.

1977 was the dawn of the age of the rov. My new company Sub Sea Surveys made a profit by offering pipeline inspection by *Consub 2* at one half the day rate of manned submersibles.

The North Sea construction boom fell away.

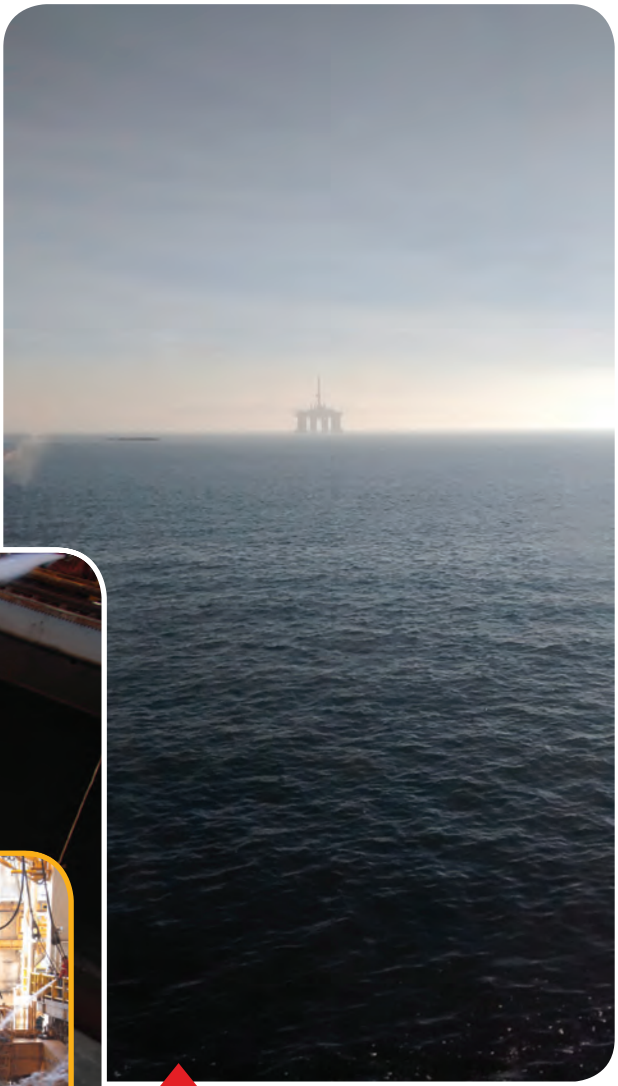
The 1977 market for manned subs was £9 million, giving work for nine vehicles — 22 were available for North Sea work. The rov ascended over the funeral rites of the manned submersible companies. £60 million was consumed by half a dozen manned sub companies in less years. There would have been greater contribution to UK energy by burning all this money!

So the cycle continues. Today rovs are in a state of 2:1 oversupply with the added complication that their major owners, the diving companies, are in the midst of serious financial problems. However, the promised construction boom of late '85 onwards offers hope of profits, but perhaps to more educated contractors.

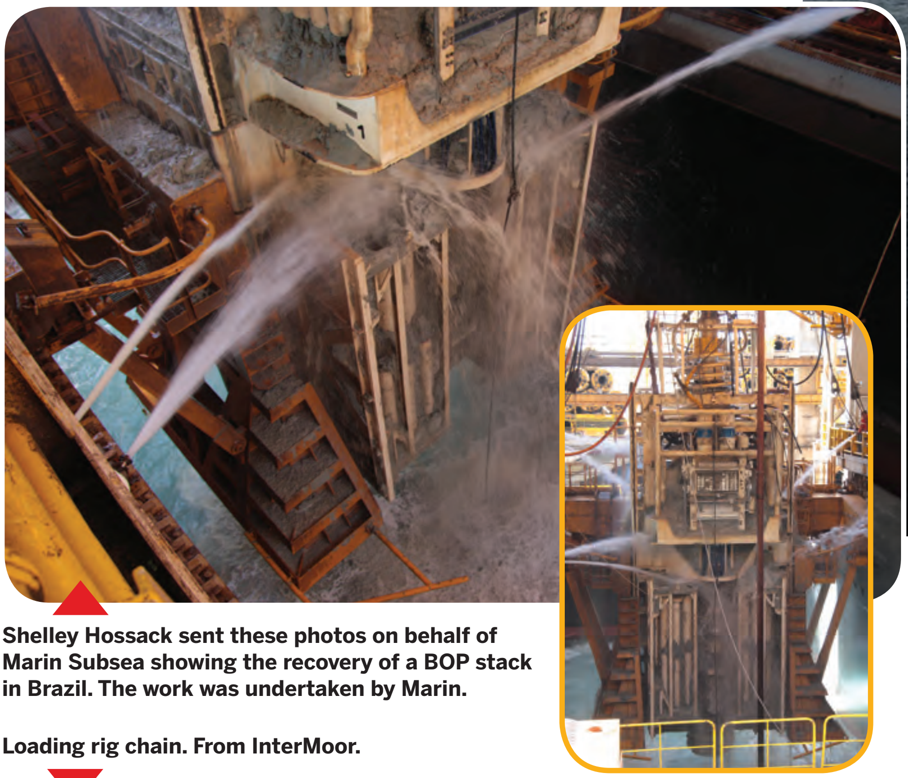
The text book may be wrong — market share does not always equal profit share. There must be market attacks available to the underwater contractors other than kamikaze. ❜

Hard at work

We asked and you delivered! *OE* put out the call to our readers back in August to submit their offshore work photos, and send they did! Readers from all over the globe sent in fantastic photos of hard work underway from recovering a BOP stack in Brazil to installing a suction pile in Asia, to transporting topsides to the Gulf of Mexico. We couldn't be prouder to showcase all the hard work our readers do every day. Cheers!



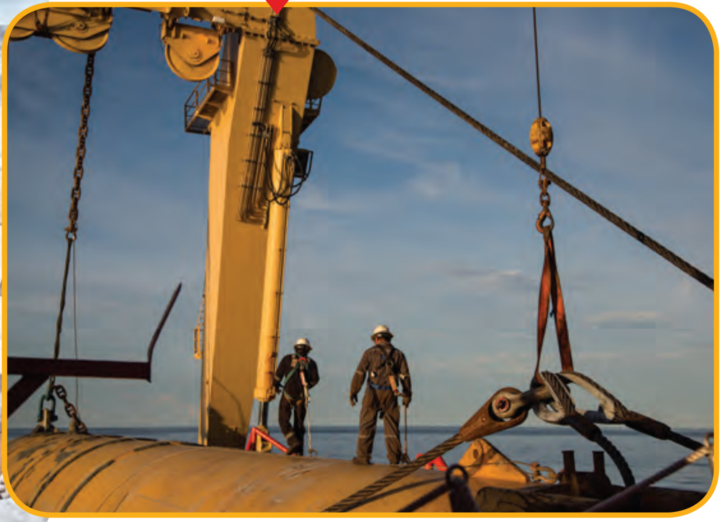
Sharon Roe shares this photo she calls "Ghost plaform of the Firth of Forth" featuring a platform lost in the fog near Edinburgh, Scotland.



Shelley Hossack sent these photos on behalf of Marin Subsea showing the recovery of a BOP stack in Brazil. The work was undertaken by Marin.

Loading rig chain. From InterMoor.

Installing a suction pile in Asia. From InterMoor.



Alan Cattel of Enautix sent in this photo of the *Dockwise Vanguard* stopped over in Singapore during a transportation float-on.

Peter Devine, of Versabar, sent in these photos of the company's heavy lift vessel, *VB 10000*, hard at work. The *VB 10000* decommissions a 2650-ton topside in the Gulf of Mexico. The twin gantries rise 260ft above the waterline. With a rated lift capacity of 7200-tons it is the largest lift vessel ever built in the United States.

The *VB 10000* uses a custom-engineered subsea lifting device, The Claw, to retrieve a 1800-ton topside from the sea floor. It had been sunk by a hurricane. The photographs were taken by Versabar staff photographers.

Using asset integrity to enhance the bottom line

Gregory Hale discusses how operators can get more out of their current assets, and add more to the bottom line.

Systems on a platform floating in the middle of the ocean were running the same way it had been from the heady days of oil coming in at over US$100/bbl.

Those days, however, are gone and looking like they will not be back for a while, if ever, so the operator knew they needed to remain profitable, they had to squeeze as much out of their technology to cut costs, reduce the human footprint and increase the ability to visualize the equipment on the platform.

Engineers knew what they had to do. To get more out of what they had, they felt predictive and proactive monitoring of the process and equipment health was paramount. Instead, though, they had islands of monitoring systems.

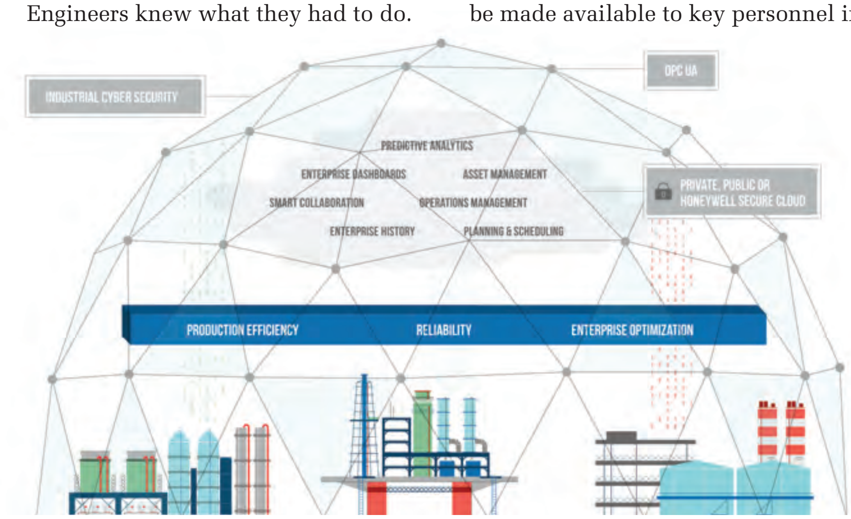
The operator needed to focus on the sustainable performance of the organization and on boosting economic viability. Faced with the enormity of technical, regulatory and competitive challenges oil and gas producers need to ask:

- How can the organization optimize production from assets with fewer on- and offshore personnel?
- How can shut-ins and interventions caused by equipment failures and other abnormal conditions end up predicted and prevented?
- How can critical optimization data be made available to key personnel in proper context throughout the organization in order to best use the skills of specialists in improving business process and decision-making efficiency?

"The platform had standalone performance monitoring, electrical health monitoring, their condition monitoring for vibration, diagnostics information for smart devices," said Bart Winters, product director for asset management solutions at Honeywell Process Solutions. "What they wanted to do is to effectively monitor and assess the health of the systems on the platform remotely to bring it in to a central overarching monitoring environment."

While those standalone monitoring systems worked individually, they were just not efficient in getting relevant information in the hands of the right people to make quick, real-time decisions. In a down market where profits remain tight, operators need to get the most out of every single asset. That is why the time is right to create a smarter environment to get the biggest return on producing assets while ensuring a safe environment.

"Production for the most part is up, but producers are planning on oil prices staying low," said Dan O'Brien, global director of production management at Honeywell Process Solutions. "They are going to survive and maintain profitability by increasing production efficiency and cost savings. The game changer is software and technology, which is going to derive so much (information) in the next few years for production efficiency and cost savings. Software driven technologies matter."



Asset optimization has multiple data points to pull information to every part of the enterprise. All images from Honeywell.

Gaining more visibility into what is happening in the process not only allows for greater asset usability and less unplanned downtime, but also a safer environment.

With over 6700 platforms in operation around the world, at least 30% have been in operation for more than 20 years – working way beyond their original design. That means operators have to make sure an asset can perform its required function effectively, safely and productively.

Add to that industry averages suggest 5% of production capacity is lost each year due to unplanned downtime and in a down market those numbers can add up. More than any other reason, equipment failures are the most common culprit. When you combine this with fewer people and money, keeping the operation running can be daunting.

"Producers need to look at three main areas: Get the most out the assets running today, a relentless focus on safety and take advantage of operational improvements in operations," O'Brien said.

Three other areas to boost operational integrity include:

- Better connectivity between assets
- Real-time analytics capabilities getting smarter
- Allow for greater and smarter work environments and collaboration

"There is increased complexity in the equipment we are monitoring and the processes and the time to respond to information to make decisions," Winters said. "Another challenge we see is the aging workforce and the skills shortage. There is more demand for remotely hosting and providing support for facilities remotely with subject matter experts. We see a lot of firefighting instead of proactive optimization and proactive or predictive maintenance. Instead of planning effectively, we see a lot of emergency work, which means more time and money is involved to get resources to the platforms."

Squeezing out cost

When operators are using a planned comprehensive optimization program, there are positive results.

What we have seen is a reduction in operating and maintenance costs by $15-30 million a year by reducing downtime operating costs by being able to proactively predict pump and compressor failures as well as shut ins," Winters said. "The indirect savings are up to $50 million a year by reducing the staffing requirements and other things."

Just finding information available for a compressor has its challenges, Winters said. How does an engineer know and understand the health of that equipment? Operations may report a problem and then the engineer has to ask if the issue can wait until the next turnaround, then what is important for me in the next turnaround from a maintenance standpoint, and am I really operating efficiently right now? To find answers to those questions, today that engineer has to go to a variety of resources to find answers.

"Capturing data that is available and capturing it in the context of the asset is important," Winters said.

By integrating real time process data with online and offline condition monitoring, it is possible to identify, define and monitor process parameters that extend assets' lives and result in more reliable operation.

Let's face it, process changes have a significant impact on equipment behavior and reliability, which in turn show up in the process data. It is now possible to see how process parameters affect asset performance.

Keep systems running

One of the challenges with asset integrity and equipment effectiveness is to reduce unplanned downtime.

"One user believes they have upwards of 50% of their maintenance costs coming from misoperation of equipment," Winters said. "By being able to identify those behaviors and practices and improve on them, you will see an improvement on the lifecycle and reliability of the equipment.

"Being able to identify behaviors and practices, we see an improvement in the lifecycle and reliability of equipment. We also see the safety challenge. Processes that are more reliable are safer process and safer places to work." OE

Technology to help hike production

Norway's Statoil needed to offset declining production levels, so it went about incorporating new technologies into production processes to transform, streamline and improve them. Compared with a worldwide average recovery rate of 35%, Statoil sought to increase its rate to 55% for subsea platforms and 65% for fixed platforms.

Statoil partnered with IBM, ABB, Aker Kvaerner and SKF to create a new process framework that links advanced real-time sensing capabilities in the field to make collaborative and analytical resources accessible across the enterprise.

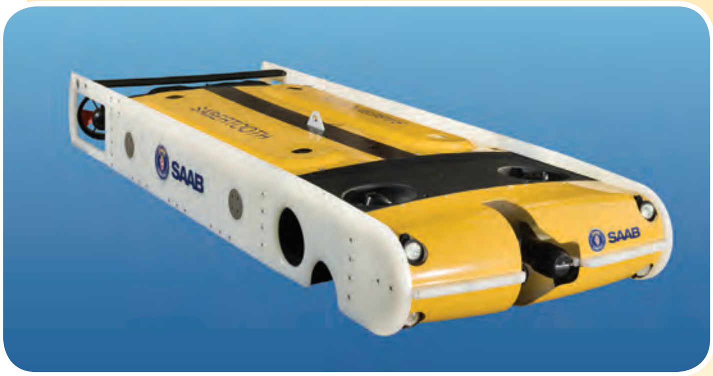
Boosting the recovery rate of existing fields could add billions in revenues.

The plan's objectives were:

- Increase in oil and gas production 5% annually through reductions in unplanned equipment downtime.
- Have a 30% reduction in costs through the use of predictive maintenance practices.
- A 5% hike in oil and gas production through planned and improved maintenance processes.
- 30% reduction in costs through the use of predictive maintenance practices.
- Extend oilfield life and increase in production yield through "smart" field management, enabled by real-time wireless sensing of subsurface oil field installations.
- Lower costs and improve production efficiency through the consolidation of well monitoring and management into onshore facilities.
- Increase interdisciplinary collaboration through improved information sharing.

Solutions

Saab demos Sabertooth at NASA



UK-based Saab Seaeye demonstrated its Sabertooth AUV/ROV at NASA's Neutral Buoyancy Lab at the Johnson Space Center in Houston in November, where guests watched the a hybrid system perform in a simulated subsea environment.

During the demo, the Sabertooth left its docking unit and switched from manual to autonomous mode to inspect a pipe. While scanning the pipe, the Sabertooth followed the profile of the pipe, and upon completion, maneuvered to the next objective, a subsea valve. Approaching the valve, operations modes switch from autonomous to manual and the Sabertooth was flown to the valve, where it engaged the torque tool, and operated it. The vehicle then disconnected, switched back to autonomous mode and followed pre-programmed instructions to swim across the demonstration area with a structure in its way. While traveling its pre-programmed route without operator input, the Sabertooth detected the impeding structure, slowed, determined another route, redirected, and moved past the obstacle to its destination.

The Sabertooth design is available in a single or double hull, both rated for 3000m depth, and is capable of forward speeds of up to 5 knots for the single hull and 4 knots for the double hull. With six degrees of freedom, the vehicle can adjust its heading, depth, pitch, roll and altitude, allowing it to adapt to a range of operating conditions. Additionally, the Sabertooth is capable of step functions, which allow adjustments in .1m increments, stabilizing the vehicle, and allowing it to hover in a stationary position. The hybrid vehicle is capable of operating in three modes: autonomous, operator-assisted, and manual operation. *–Jerry Lee*

www.seaeye.com

Impress releases new transmitter

Impress Sensors and Systems launched a new range of subsea pressure and level transmitters, suitable for a variety of pressures and applications in depths up to 3000m and external pressures up to 300 bar.

The SS series of subsea pressure and level transmitters uses a ceramic pressure sensor, which provides corrosion resistance and can be continuously submersed in seawater. The transmitters are fitted with a choice of subsea-certified connectors and locking sleeves to suit specific customer requirements. The housing is available in a choice of seawater-compatible materials, including 316L stainless steel, high grade Duplex stainless steel or Marine bronze. In addition, all sensors in the series provide dual independent, 2-wire, 4-20mA outputs, with no signal loss over long cable lengths. Nominal pressures are from 1-400 bar, with operating temperatures are from -20°C to +60°C in non-freezing media.

The SS transmitters are suitable for a wide range of subsea oil and gas, marine and offshore applications, including pressure, level and depth measurement on unmanned surface vehicles (USVs), remotely operated vehicles (ROVs) and other subsea hydraulics systems.

www.impress-sensors.co.uk

Weather unleashes JetStream RFID

Weatherford has developed an alternative circulation sub that provides fullbore flow-through without the need for ball-drop actuation. The JetStream RFID drilling circulation sub is a remotely actuated device that facilitates drilling and hole cleanup operations.

The circulation sub uses active RFID technology to communicate open and close commands. An RFID tag dropped from the surface circulates through the sub, where a built-in antenna receives the tag signal to either close or open the valve. A battery-powered electric motor then drives a hydraulic pump that moves the valve to the preprogrammed position. The sub can be selectively actuated an unlimited number of times for a high degree of operational flexibility. And it can be used with up to 16 RFID-actuated tools in series.

The sub also provides open communication between the drillpipe and annulus to place lost-circulation material (LCM) pills precisely in critical intervals. For one North Sea well drilled through a soft porous limestone formation with natural faults and a tendency for seepage, the RFID sub was actuated (opened and closed) a total of eight times to deliver LCM pills and keep fluid losses low, thus allowing the well to reach target depth.

www.weatherford.com

Activity

Heerema opens innovation center

Dutch engineering and fabrication firm Heerema Fabrication Group (HFG) has opened its new Heerema Innovation Center, where it plans to develop next-generation welding robots, and use latest gaming and data processing technology.

The center is close to HFG's Zwijndrecht headquarters. Of the new center, the firm says: "it symbolizes the course that HFG wants to sail: working even faster and more efficiently."

The first project of the Heerema Innovation Center is the welding robot, which has been developed by Valk Welding together with HFG.

"This robot does not replace our welders; it complements them," says HFG CEO Koos-Jan van Brouwershaven. "A welding robot will also be installed in our company training school where our welders will learn to work with it. Welders are almost always in short supply. The welding robot enables them to concentrate on the more challenging tasks, while the welding robot can be used for other work."

HFG continues: "The first welding robot has two welding arms and operates very precisely. The colossal device weighs 50-tons, and unfortunately can't really climb yet." That will be the next challenge for the Innovation Center where more welding robots will be developed. Van Brouwershaven sees many more opportunities for the Innovation Center. ▪

Schlumberger, Cameron merger cleared

The US Department of Justice (DOJ) has cleared the proposed US$14.8 billion merger between Schlumberger and Cameron International without any conditions. The deal, which is still subject to approval by Cameron stockholders, was unanimously approved by both boards of directors. The merger agreement offers Cameron shareholders 0.716 shares of Schlumberger common stock and a cash payment of $14.44 in exchange for each Cameron share. If approved, Schlumberger and Cameron expect to close the merger sometime in Q1 2016. Schlumberger has been busy over the last several months. Earlier this week, the company announced it would acquire US-based Fluid Inclusion Technologies. In September, the company moved to add supermaterials company Novatek to its drilling portfolio.

Apache rejects Anadarko bid

US-based Apache has rejected a takeover proposal from Houston-based independent Anadarko Petroleum, which consisted of an all-stock transaction offer.

Al Walker, Anadarko chairman, president, and CEO, confirmed that the non-binding offer that was made to Apache, in addition to the decision to withdraw the proposal.

"Our efforts to enter into a mutually acceptable confidentiality agreement for the purpose of exploring the merits of a potential transaction were summarily rejected and no discussions of substance occurred. We are unwilling to pursue the transaction without access to detailed non-public information, and based on our analysis, which shows that Apache appears to trade at or near full value currently, the offer was withdrawn," Walker said.

Premier Oil sells Norway business

Norway's Det Norske has bought UK-based independent explorer Premier Oil's Norwegian assets for US$120 million.

The Premier Oil assets include the Vette development, for which Premier Oil has been working on a floating production facility solution, as well as the adjacent Mackerel and Herring discoveries, and a non-operated interest in the Frøy.

The deal, expected to complete by the end of the year, also includes seven exploration licenses in the Norwegian sector of the North Sea.

Aker, Man Diesel form alliance

Aker Solutions and MAN Diesel & Turbo agreed to form an alliance to develop the next generation in subsea compression systems that can be used at even the smallest oil and gas fields to increase recovery and lower costs compared with conventional platform solutions.

The alliance combines Aker Solutions' capabilities in subsea processing, compression systems, controls, systems and interventions with MAN Diesel & Turbo's turbomachinery technology and its gas compression expertise. The compression systems will be based on proven technology and for use at small subsea fields as well as large deposits such as Åsgard field in Norway.

A key objective of the partnership is to develop new, cost-effective technology for high-capacity subsea compression systems.

Spotlight

By Elaine Maslin

Sewing seeds

We're in tough times, but that also means there's an opportunity to seek new solutions, according to Proserv's David Lamont. Elaine Maslin went to hear the CEO's views.

In 1982, a young(er) David Lamont left his home country, Australia, and travelled to Aberdeen to join an industry in the midst of a major boom. The idea was to stay for two years then go back to Australia.

Like many who come to the North Sea, his first visit wasn't to be his last. After travelling the world with Schlumberger, the engineering graduate soon found his feet in business management, both in and out of Schlumberger. He co-founded Omega Completion Technology, helped Schlumberger re-organize its well completions and productivity business in Russia, and rebuilt ABB Vetco Gray, as it was then, before helping oversee the sale of Vetco International to GE Oil & Gas in 2007.

A man unafraid of trying something different, he also spent just under a year out from the oil business as director of marketing & sales at Virgin Direct in Norwich, the city he now calls home.

Now, however, he is more than four years into helming Proserv – a relatively new brand with some strong oilfield heritage. After working for the big firms – Vetco, ABB, Schlumberger – he's found a smaller firm with a niche, a niche which could come into its own in today's low oilprice environment.

"Coming from bigger companies with greater technology and capability, we saw and still see a need for companies providing fit for purpose solutions, at a lower cost and more reliable and faster," he says. "It means taking a much more 'service' approach than a manufacturing approach."

The approach matches today's environment, one which is very different to the one Lamont first joined in Aberdeen. "It was boom time [then]. Every pub had kit bags stacked high outside as people came back onshore. They were wild days and too wild in many ways. It was extremely entrepreneurial, maybe a bit gung-ho sometimes, but we have gone through a period of the industry maturing."

Safety and planning are better today, he says, but, after a period in the 1990s, where operators collaborated to help bring projects like high-pressure, high-temperature fields, complex geological fields, or smaller marginal fields on stream, with appropriate risk sharing, some of that appetite was lost, he says. While a move was made from bespoke design to standardization, this resulted in the highest standard products being chosen, often unnecessarily – i.e. gold-plating – says Lamont. While outsourcing engineers worked up to a point, when they were integrated into the operators, using day raters hasn't help align goals or achieve the best, most efficient outcomes. "We lost that alignment from 2000-2013, and that's why, in 2011 we brought together Proserv. We could see costs were escalating, particularly for marginal fields."

Lamont joined Proserv in 2011, joining some ex-colleagues from Vetco, at which point the company had been more like a "federation of companies." These outfits were consolidated and brought under one brand, Proserv, with "a common platform, common ownership, and a common direction with a global management structure and integrated product lines."

Proserv is looking to do something a bit different, not competing for EPC contracts with the larger players. This means focusing on more modest, potentially marginal projects that need a lower cost solution, as well as brownfield projects, need alternatives to tearing out the old and replacing them with the new.

As an example, Proserv has worked to develop ways to retrofit multiphase monitoring, subsea electronics modules, sensors and even cameras, so ROVs don't have to be deployed. It has developed a way to add communications through existing communications lines. And the firm continues to look for new solutions, evidenced by its recent purchase of through-water acoustic communications and control firm Nautronix.

David Lamont Photo from Proserv.

Despite the environment the industry is in, Lamont is positive, seeing the opportunity for improvement and for marginal developments. "It is not a great period for anyone, but I liken it some seeds which will only germinate after going through a bush fire," he says. "All companies need to think how to do things differently, we can't just revert back to the way we were working."

Creating better working partnerships with operators will also help the industry. As an example, Proserv was signed up as a subsea partner by MOL Group, which has no North Sea operating assets, but is keen to learn from and work with the supply chain.

Crucially, making sure the business is the right size for today's market, while also recruiting talent, is a challenge, but it has to be done for the future of the business, he says. The wider industry should take note. OE

Editorial Index

Advertiser Index

OE Advertising sales

NORTH AMERICA
John Lauletta (N-Z)
Phone: +1 713-874-2220
jlauletta@atcomedia.com

Amy Vallance (A-M)
Phone: +1 281-758-5733
avallance@atcomedia.com

UNITED KINGDOM
John Steward, Alad Ltd
Phone: +44(0) 7742 570064
john@aladltd.co.uk

NORWAY/DENMARK/SWEDEN/FINLAND
Brenda Homewood, Alad Ltd
Phone: +44 01732 459683
Fax: +44 01732 455837
brenda@aladltd.co.uk

ITALY
Fabio Potesta, Media Point & Communications
Phone: +39 010 570-4948
Fax: +39 010 553-00885
info@mediapointsrl.it

NETHERLANDS/AUSTRIA/GERMANY
Arthur Schavemaker, Kenter & Co. BV
Phone: +31 547-275 005
Fax: +31 547-271 831
arthur@kenter.nl

FRANCE/SPAIN
Paul Thornhill, Alad Ltd
Phone: +44 01732 459683
paul@aladltd.co.uk

ASIA PACIFIC
Eugene Herman Tumanken
Phone: +65-8700 9570
etumanken@atcomedia.com

PUBLIC NOTICE

USPS STATEMENT OF OWNERSHIP, MANAGEMENT AND CIRCULATION

1. Publication title: OE (Offshore Engineer)
2. Publication number: 1705-8
3. Filing date: November 11, 2015
4. Issue frequency: Monthly
5. Number of issues published annually: 12
6. Annual subscription price: $160.00
7a. Complete mailing address of known office of publication: AtComedia, 1635 W Alabama St., Harris County, Houston, TX 77006
7b. Contact person: Shirley Ford
7c. Contact telephone: 713-874-2224
8. Complete mailing address of known office of publisher: AtComedia, 1635 W Alabama, Houston, TX 77006
9a. Full name and complete mailing address of publisher: Brion D. Palmer, 1635 W Alabama, Houston, TX 77006
9b. Full name and complete mailing address of editor: ---
9c. Full name and complete mailing address of managing editor: Audrey Leon, 1635 W Alabama, Houston, TX 77006.
10. Owners: International Exhibitions Inc. (50%), 1635 W Alabama, Houston, TX 77006; PL Investments LLC (50%), 1635 W Alabama, Houston, TX 77006
11. Known bondholders, mortgagees, and other security holders owning or holding 1% or more of total amount of bonds, mortgages or other securities: None
12. Tax status: Has not changed during preceding 12 months
13. Publication title: OE (Offshore Engineer)
14. Issue date for circulation data below: December 2015
15. Extent and nature of circulation:

	Average no. copies each issue during preceding 12 months	No. copies of single issue published nearest to filing date
a. Total number of copies	33,830	32,910
b. Legitimate paid and/or requested distribution:		
1. Outside county paid/requested mail subscriptions stated on PS Form 3541	13,640	13,937
2. In county paid/requested subscriptions stated on Form 3541	0	0
3. Sales through dealers and carriers, street vendors, counter sales and other paid or requested distribution outside USPS	15,172	15,312
4. Requested copies distributed by other mail classes through the USPS	0	0
c. Total paid and/or requested circulation	28,812	29,249
d. Non-requested distribution:		
1. Outside county nonrequested copies stated on Form 3541	3236	2483
2. In county nonrequested copies stated on Form 3541	0	0
3. Nonrequested copies distributed through the USPS by other classes of mail	0	0
4. Nonrequested copies distributed outside the mail	950	553
e. Total nonrequested distribution	4186	3036
f. Total distribution	32,998	32,285
g. Copies not distributed	832	625
h. Total	33,830	32,910
i. Percent paid and/or requested circulation	87.31%	90.59%
16. Electronic copy circulation		
a. Requested and paid electronic copies	12,292	12,421
b. Total requested and paid print copies + requested/paid electronic copies	41,104	41,670
c. Total requested copy distribution + requested/paid electronic copies	45,290	44,706
d. Percent paid and/or requested circulation (both print & electronic copies)	90.76%	93.21%

☒ **I certify that 50% of all my distributed copies (Electronic & Print) are legitimate requests.**

17. Publication of statement of ownership: Will be printed in the December 2015 issue of this publication.

18. Signature and title of publisher:

Brion Palmer, Publisher

Date: 11/11/2015

I certify that all information furnished on this form is true and complete. I understand that anyone who furnishes false or misleading information on this form or who omits material or information requested on the form may be subject to criminal sanctions (including fines and imprisonment) and/or civil sanctions (including civil penalties).

Bells and whistles

Odfjell Drilling's *Deepsea Aberdeen* has all the bells and whistles for working west of Shetland. Elaine Maslin takes a look.

It's new, bespoke, highly automated, multifunctional and multipurpose. No, it's not the latest Bond Aston Martin, it's Odfjell Drilling's sixth generation dual-derrick semisubmersible drilling rig *Deepsea Aberdeen*.

The unit, Odfjell's latest newbuild, started working for BP on its West of Shetland assets, including the Quad 204 redevelopment, on the UK Continental Shelf on 21 April 2015. Under Odfjell's largest ever contract, the unit is on a seven-year drilling program for BP and its co-venturers, starting with two production wells and a water injector on the Loyal field, which is part of the Quad 204 redevelopment, before moving to the Schiehallion field, also part of Quad 204 *(OE: September 2015, June 2015, July 2013).*

The new bespoke unit, capable of drilling in up to 3000m water depth, has dual derrick capacity for dual operation, fully automated "green rig" with no-leak design, and is fitted out in order to work in environments as harsh as the West of Shetland and the Arctic.

Despite hiccups during the construction of the rig setting back the initial delivery date – it sank at its wharf late 2013 after water ingress, and then part of a BOP was damaged during sea trials – she's a highly advanced unit, says proud rig manager Stein Harald Nielsen, who has been in charge of the *Deepsea Aberdeen* from four months before Odfjell took delivery of the unit from Daewoo Shipbuilding & Marine Engineering (DSME) in South Korea.

"It is probably the most advanced rig in the world," he says. "The system and equipment is really state of the art. We do not have any personnel near the rig floor, everything we do is more operated and that is something new for many of the staff."

Deepsea Aberdeen is the latest in a string of GVA 7500 (enhanced) harsh environment design rigs Odfjell has had built, following on from sister rigs *Deepsea Stavanger* and *Deepsea Atlantic,* also built at DSME.

But, *Deepsea Aberdeen* is the cream of the crop, having had extra bells and whistles added to meet long-term customer BP's specifications. This includes the dual derrick capacity (1000-ton and 500-ton), with a main and auxiliary work center and two (HPS-1000) top drives instead of travelling blocks, for simultaneous operations, and dual and single active heave compensating drawworks for increased performance, efficiency, safety and redundancy. The drawworks, mud pumps, and HPS-1000 top drives were supplied by NOV in Norway.

Being able to perform dual operations is a real advantage, Nielsen says, especially when it comes to efficiency and so far the results have been good. "It obviously takes some time – you have to crawl before you can walk – but the crew has been fantastic and we have seen some really efficient drilling operations in the 6-7 months we have been here," he says.

The *Deepsea Aberdeen* is also equipped with a full conventional mooring spread for operations in 70-500m water depth, but can also work in up to 3000m (10,000ft) water depth on DP. Its 7500-tonne loading capacity in all operating conditions enables efficiency, with a reduced need for re-supply. It can also be fully winterized for working in Arctic conditions.

The rig, classified by DNV GL and able to accommodate up to 158 people, has two BOPs, one six ram electric and a five-ram hydraulic MUX BOP, both 18-3/4in and 15,000psi-rated.

The green rig design concept means any leak paths are fully enclosed so nothing can leak into the environment. It has full a dual mud system for reduced contamination and separate completion fluid system. It has four, high-pressure, high-capacity, mud pumps (14-P-220, 7500psi), and six high-capacity shakers. There is also a large set back capacity for drillpipe and casing.

If you want to see more, the rig even has its own Facebook page – something Bond's latest Aston Martin doesn't have either. **OE**

The *Deepsea Aberdeen* working west of Shetland.
Photo from Odfjell Drilling.

FURTHER **READING**

Adding EOR to Quad 204
www.oedigital.com/component/k2/item/10286-adding-eor-to-quad-204

OE

PRINT or DIGITAL

- Actionable Intelligence, on and for the Global Offshore Industry
- Field Development Reports
- Global coverage with Regional updates on key exploration areas
- Case Studies on New Technology
- Serving the industry since 1975

SUBSCRIBE FOR FREE!

FAX this form to
+1 866. 658. 6156 (USA)
or
visit us at
www.oedigital.com

1. What is your main job function?
(check one box only)

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

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

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

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

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

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

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

☐ **YES!** I would like a FREE subscription to ***OE***
☐ *no thank you*

How would you prefer to receive ***OE***?
Print ☐ Digital ☐

Name: ____________

Job Title: ____________

Company: ____________

Address: ____________

City: ____________ **State/Province**: ____________

Zip/Postal Code: ____________ **Country**: ____________

Phone: ____________ **Fax**: ____________

E-mail address*: ____________

By providing your fax and/or email address,you are granting AtComedia permission to contact you regarding your subscription and other product offerings. May AtComedia contact you about other 3rd party offers for:

Email: ☐Yes ☐No **Fax:** ☐Yes ☐No

Signature (Required): ____________

Date (Required): ____________

Please Note: Only completed forms can be processed. Your signature does not obligate you or your company any way.

S31OS1


Hole Depth
6452.43
Bit Position
6452.43
RT by Time
Flow Out Percent
40
Gain Loss
-3.4
Mud Weight In
8.900
Trig Hkld
Chart Setup
Print
Export
Annotation
Actuals
Plan
Alarm
Sep-22-2014
WPDA - MSE
Top Drive RPM
Top Drive Torque
WPDA - Ref RPM
WPDA - Heartbeat
WPDA - Status
Pump Pressure
Flow In Rate
Pump SPM 1