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Dutch offshore suppliers are innovating to keep ahead, providing solutions in ever deeper and colder waters globally.

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Boskalis is eyeing an increased role in offshore oil and gas and renewables projects.

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The Dutch have long dominated the heavy lifting market, and their domination looks set to continue.

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OE Region is a special report produced by *Offshore Engineer*, published by AtComedia.
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- ☐ 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)*_____

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(check one box only)

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

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

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(check all that apply)

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

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Deepwater intervention

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Claudio Paschoa discusses deepwater intervention equipment and services with Ativatec's Daniel Almeida Camerini.

ON THE COVER

Heavy metal. Allseas' twin-hull *Pieter Schelte* mega-heavy lifting vessel is due to berth at the port of Rotterdam's new Maasvlakte, 20 years after it was conceived. The vessel measures 382m long and 124m wide, with a 48,000-tonne lift capacity. Read the full story on page 12 of our special report *OE Region*: *Dutch Offshore*.

4,571,739

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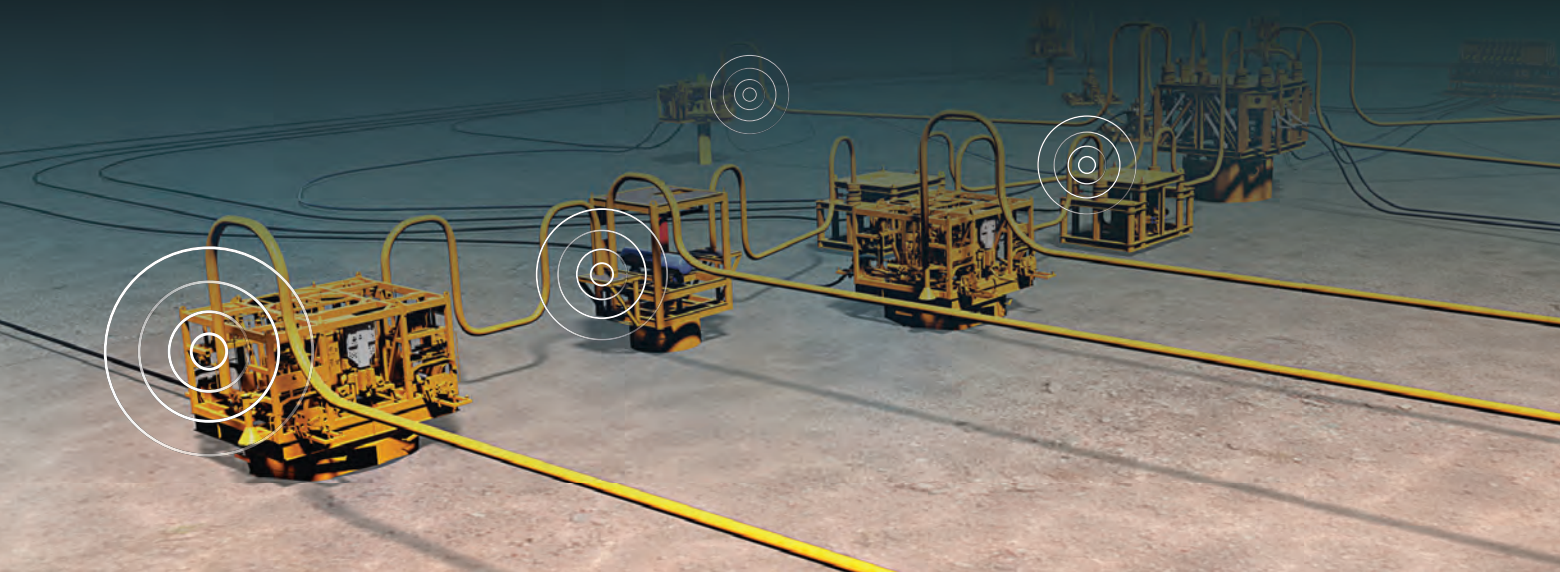

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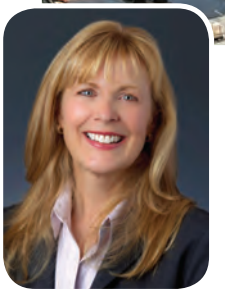

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OE (Offshore Engineer) is published monthly by AtComedia LCC, a company wholly owned by IEI, Houston. AtComedia also publishes **Asian Oil & Gas**, the **Gulf Coast Oil Directory**, the **Houston/Texas Oil Directory** and the web-based industry sources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

US POSTAL INFORMATION
Offshore Engineer (USPS 017-058) (ISSN 0305-876X) is published monthly by AtComedia LLC, 1635 W. Alabama, Houston, TX 77006-4196. Periodicals postage paid at Houston, TX and additional offices.
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Intelligent Manufacturing Systems

As offshore platforms are automated from top to bottom, and integrators stitch together disparate systems and protocols into a smoothly-running continuum, the inevitable next step will be assimilation of the performance data with onshore management systems. **Bob Felton** discusses how the offshore industry is getting ready for Industry 4.0.

What's Trending

Discoveries and entrances

- **Shell hits Norphlet pay in GOM**
- **South China Sea oil find**
- **Mitsui eyes Mexico**
- **Wison-WorleyParsons eye Asian FLNG**

People

Meehan elected SPE 2016 president

SPE appointed D. Nathan Meehan, Baker Hughes senior executive adviser, as its 2016 president, effective 29 October 2014.

New UK energy minister named

UK Prime Minister David Cameron, in his biggest government shake-up since coming to power in 2010, appointed Matthew Hancock his fourth energy minister in less than two years.

4th Annual Global FPSO forum

What's going on in today's FPSO business?

Plan to attend the two day conference and participate in the Mooring Special Session Workshop held on September 23rd from 1:00 – 5:00 p.m.

Tuesday, September 23

Session 1:
Introduction, Recap & Update from 2013
Arjan Voogt, Marin

Deepstar Chain
KT Ma, Chevron 1:10 -1:30 PM

Changes in Design Philosophy
Hongbo Shu, Shell 1:30 -1:50 PM

Mooring Line Replacement
Subir Bahttacharjee, ExxonMobil 1:50 - 2:10 PM

Coffee Break 2:10-2:30 PM

Session 2:
Mooring Integrity - A look At Solutions to Issues Discussed Last Year

Field Proven Real Time Continuous Integrity Monitoring of FPSO Mooring Lines & Risers Using Advanced Sonar Technology
Angus Lugsdin, Tritech International Limited
2:30-2:50 PM

A Practical Look into Preventing Mooring Line Failure at the Fairlead
Jonathan Miller, InterMoor
2:50-3:10 PM

Involving Repair & Installation Experience into the Mooring Design Process
Tom Koster
3:10-3:30 PM

Coffee Break 3:30 - 3:50 PM

Session 3:
Turrets & Station Keeping
2:30-2:50 PM

Bigger, More Complex, More Advanced: You Want Us To Do All That And Walk On Water Too?
Thomas Kolanski, BW Offshore

Session I:
The State of the Business
Moderator: Peter Lovie, Floating Systems, Peter M. Lovie PE, LLC.

Keynote: Expectations, Opportunities, Issues in the Offshore Community

Randall Luthi, President, National Ocean Industries Association 8:00-8:40 AM

Introductions and Opening Remarks
Brion Palmer, AtComedia
Barry Donovan, Raymond James 7:45-8:00 AM

Wednesday, September 24

Opening Reception on the Exhibit Floor
5:00- 7:00 PM

Discussion & Closing Remarks 4:50 5:00 PM

Challenges in Deepwater Disconnectable Turret Design
Jeff Tan, NOV 4:30 - 4:50 PM

Turret Mooring Design for Squall Conditions
Arun Duggal, SOFEC
4:10 - 4:30 PM

Mooring System Options in Shallow Water
Jack Pollack, SBM Offshore
3:50 - 4:10 PM

Contracting, Building, Operating And Financing - And Getting Paid For It. Leasing Is Not What It Used To Be!
Puneet Sharma, Modec International

What the FPSO Contractor of the Future will Look Like
Cobie Loper, SBM Offshore

Operator Comments, Discussion with Audience
Blake Moore, Shell
8:40-10:05 AM

Morning Coffee Break in the Exhibit Hall 10:05-10:35 AM

Session II:
The Future From Perspective Of Industry Advisors: Expectations, Opportunities And Issues
Moderator: Barry Donovan, Raymond James

Intro: Quiz For Audience
Barry Donovan, Raymond James

Worldwide Projects - A Forward Look At Activity Levels and Trends
Jim McCaul, International Maritime Associates

Financing Activity And Trends In The Offshore Industry
Barbara Gronquist, SVP Shipping, Offshore, DNB Bank ASA

PROPOSITION 4:
The Cost of FPSO'S Today Actually Represents Good Value; an Optimum Balance Between Capital Cost, Operating Cost, And Production Efficiency

PROPOSITION 3:
Owners Can Do a Lot More To Drive Cost Reductions (Other Than Squeezing Contractors)

PROPOSITION 2:
FPSO Project Risks Are Being Mis-Allocated Between Owners and Contractors, Resulting In Higher Costs

PROPOSITION 1:
Standard, Contractor-Developed FPSO Configurations and Designs Provide Significant Cost Saving Opportunities That Should Be Taken Seriously

Session III: Crossfire - Facing the Realities of Cost and Risk - The Big Debate of 2014
Moderator: Dick Westney, Westney Consulting

Lunch in the Exhibit Hall
12:10-1:10 PM

10:35-12:10 PM
Closing Discussion; Audience Q&A For Speakers

Recurring Trends And Issues In FPSO Contracts - 2014 and Beyond
Kerry Williams, Chamberlain Hrdlicka

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WRAP-UP:
Final Observations From Panel and Audience

1:10-2:55 PM

Afternoon Break in the Exhibit Hall 2:55- 3:25 PM

Session IV:
Possible Game Changing Developments in the FPSO Industry
Moderator: Jim Wodehouse, Water Standard

The Dockwise Vanguard for FPSO "Drydocking" for on Location Refurbishment and Repair
Ryan Rush, Dockwise

Subsea Processing and FPSOs - Equipment Realities and Changes in Field Developments
Janardhan Davalath, FMC Technologies

Impact of Local Content on Project Performance in Offshore Field Developments
Neeraj Nandurdikar, IPA

Panel Discussion: How Immediate Are These Game Changers For The FPSO World? Others to Worry About?
Session Speakers

3:25-5:20 PM

Coffee Break in the Exhibit Hall 10:10-10:40 AM

8:10-10:10 AM

Panel Discussion
Session Speakers

Governmental Regulators Respond - Current Situation Covering FPSOs in US GoM
BSEE and Capt. Nadeau, USCG

The Class Societies React to Current Needs
Ken Richardson, ABS

Opening Discussion with Operators - What We Are Looking For

The Difficult Truths of Deteriorating Confidence in Standards
Peter Noble, SNAME

Session V:
FPSO Operations - Ensuring that Operations are Safe, Reliable and Compliant with Regulations
Moderator: Peter Noble, SNAME 8:10-10:10 AM

Introductions and Opening Remarks
Brion Palmer, AtComedia
Peter Lovie, Peter M Lovie PE, LLC 8:00 - 8:10 AM

Thursday, September 25

The Forum Reception on the Exhibit Floor
5:30-7:30 PM

Session VI:
Significant FPSO Projects Worldwide
Moderator: Chris Barton, Wood Group Mustang

Noble Energy in Houston

Mexican Energy Reform
Enrique Garza, Garza Tello & Asociados S.C.

Discussion Panel: Common Trends?
Session Speakers

10:40-11:55 PM

Lunch in the Exhibit Hall 11:55-12:55 PM

Session VII:
Evolving New Business Sectors
Roberto Noce, Moss Maritime/Saipem

Gas Related FPSOs: Gas and Liquids Processing, FLNG: Projects and Mega Projects
Kathleen Eisbrenner, The Next Decade

Arctic Developments - Technical and Commercial Challenges
Hans-Martin Sand,Moss Maritime/Saipem

Challenges with Floating Production and Drilling In Arctic Environments and Solutions to Overcome Them
Fredrik Major, Sevan

12:55-2:10 PM

Session VIII:
The Latest on FPSOs in US GoM
Moderator: Jeremiah Daniel, Walker Ridgebras

Going First: How It's Going In Operating the BW Pioneer
Paulo Biassotto, Petrobras

Organizer's Closing Remarks
Brion Palmer, AtComedia
3:50 PM

2:55-3:50 PM

Operator and Contractor Panel:
Shell, Petrobras, BW Offshore, Modec International, Saipem, SBM Offshore, Sevan

Session IX:
Closing Panel Discussion - What's Ahead, Pulling it all Together - Comments from the Audience, Wrap Up and Closing Remarks
Blake Moore, Shell

2:10-2:55 PM

Decision Processes Affecting Choice of a Development Solution in US GoM. Will There Be Any More FPSOs In US GoM?
Martijn Dekker, Shell

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Voices

Intervention innovation. As operations get more complex, OE asked:

How have you seen well intervention technology evolve?

Rapid advances in wellbore diagnostics is arguably one of the most beneficial well intervention technologies. Using fiber optics to understand what is happening in the wellbore provides real-time information and accelerates operational decisions. We work closely with our customers to select the right technologies to intervene in a well. Once the job is designed, effective communication, execution and delivery are essential to a successful job and improving production.

Tommy Roth
Vice President, Boots & Coots

The evolution of some intervention techniques has largely been driven with the evolution of electronics and software, though the mechanism of tool transfer remains much the same: e-line and slick line. A classic example is the transition from mechanical to electronic downhole pressure gauges, that can provide either memory or surface readout options, and how this has spread to other tools such as multi-fingered callipers. For Tullow, this change is best featured with the ability to measure downhole changes in tubing characteristics where corrosion is a major problem and only memory data recording can be used, due to the lack of electric logging facilities.

Simon Sparke
Group Head, Well Integrity, Tullow Oil

One of the biggest drivers for change has been the need for technology to keep pace with the industry as it goes deeper and reaches further. Depth control is becoming ever more critical during today's increasingly complex well intervention operations so it is vitally important that the guesswork is taken out and that downhole measurements and data can be provided in real time and with pinpoint accuracy so we can confidently make the correct decisions during operations.

Jim Wright, Vice President, Sales
Altus Intervention

Over the last several years, operators have further explored and embraced more efficient well intervention technologies. This transformation is a direct response to initiatives for reducing cost while maintaining or increasing recovery. Companies that can offer these technologies in a responsive, reliable fashion have seen tremendous uptake within the industry. Growth will continue as operators continue to face the growing challenges of subsea intervention and P&A regulations on top of their normal activities.

Brian Sidle
Vice President, Marketing, Welltec

New technology that is designed to deliver predictable and reliable results is exciting. Smart intervention technology has been a game changer. The most daunting challenges around interventions are the unknowns. Thanks to onboard real-time measurement and diagnostic tools, we can make better decisions, faster. We now can provide operators with the confidence that progress will be made with every trip in the hole, eliminating the struggle with workover risk / reward equations. Furthermore, we can now equip less experienced personnel with the downhole data and know-how, previously only obtained through years of experience.

Erik Nordenstam
Product Line Director - Wellbore Intervention / Completions & Wellbore Intervention
Baker Hughes

Well construction concepts have changed from the fairly simple geometry of years past to some very complicated wells being constructed in today's oil field. From deepwater to HPHT (high-pressure/high-temperature), multi-lateral, horizontal extended reach and intelligent well designs; well intervention challenges have increased due to the complexity of the wells being drilled and completed. The industry has responded by developing sophisticated intervention tools to meet the demands of today's well designs.

Mark Rivenbark,
Vice President,
Global Sales, Meta

Historically, subsea well intervention incorporated a riser-based solution from a mobile structure (drill ship or semisub). Today, we also have the option to utilize a dynamically-positioned monohull vessel providing riserless intervention services through a subsea lubricator/well isolation system. Riserless technology may present a cost-effective solution (potentially saving 40 - 60% over riser-based), providing wireline, e-line, and stimulation services along with plugging and abandonment capabilities. At present, only a handful of working subsea lubricators/well isolation systems exist and the experience to work these safely and effectively are limited to a few companies. Risk analysis, equipment design and certification, detailed procedures, organizational effectiveness and execution experience are keys to delivering riserless intervention solution.

Randy Cazenave, Regional Wells Lead, Xodus Group

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

see more opinions on page 32

Nina Rach

Colloquy

Marine noise

Underwater noise is recognized as an adverse environmental stress and must be addressed in environmental impact assessments (EIAs). Companies have stepped forward with 3D acoustic modeling and measurement systems as countries develop regulatory guidelines for all offshore activities that generate noise.

BOEM

Since 1998, the US Bureau of Ocean Energy Management (BOEM) has partnered with academia and others, investing more than US$50million on marine noise-related research and protected species.

In 2010, the US Congress directed the BOEM to prepare a programmatic environmental impact statement (PEIS) of the potential environmental impacts of G&G activities off the Atlantic coast.

In March 2012, the BOEM published a draft PEIS, and during the 90-day comment period, it received more than 55,000 comments. It issued its final PEIS in February 2014, with several notable measures: to close areas during whale migration, to geographically separate simultaneous seismic airgun array surveys, and use passive acoustic monitoring (PAM) to supplement visual observations of marine mammals prior to and during surveys.

World Bank EHS Guidelines

As part of its risk management strategy, the International Finance Corp. of the World Bank Group has built a Sustainability Framework that it promotes as the gold standard. The IFC has developed technical reference documents with general and industry-specific examples of "Good International Industry Practice," including Environmental, Health, and Safety (EHS) Guidelines on Offshore Oil and Gas Development. The current EHS Guidelines were developed as part of a two and a half year review process that ended in 2007.

The first public consultation period for comments about revising these guidelines was open 19 February - 22 March 2013. The second (and final) public consultation to revise the guideline ended on 28 May 2014, but the World Bank will not issu results until sometime in 2015.

BRICS

News broke in mid-July that the five BRICS nations: Brazil, Russia, India, China, and South Africa, representing major emerging national economies, agreed on the structure and planned to finance a $50 billion development bank as an alternative (and rival) to the International Monetary Fund (IMF) and the World Bank. The bank will be based in Shanghai and its first presidency will be held by India.

Wiliam Gumede, writing for The Guardian, points out "there is no guarantee that a BRICS bank would not attach conditions as onerous as those of the World Bank or other development banks;" and goes on to say "It must pursue lending that is ecologically sustainable, and must promote inclusive economic growth and development."

Given that competition often fosters greater efficiencies, will the new BRICS bank be able to develop and revise environmental guidelines for investments in offshore projects any faster than the World Bank? OE

The World Bank 2014 draft EHS guidelines say the following about marine noise:

Sec. 74. Offshore oil and gas development activities generating noise include seismic operations, drilling and production activities, offshore and nearshore structural installation (especially pile driving) and construction activities, and marine traffic. Noise from offshore activities (especially from seismic operations) can temporarily affect fish and marine mammals. [see Joint Nature Conservation Committee (JNCC) Guidelines 2010, International Assoc. of Geophysical Contractors (IAGC) 2011, Joint OGP/IAGC Position Paper 2011, and further references in Section 3.0]

Sec. 75. Environmental parameters that determine sound propagation in the sea are site-specific, and different species of marine life have different hearing sensitivities as a function of frequency. An impact assessment should be conducted to (i) identify where and/or when anthropogenic sound has the potential to create significant impacts and (ii) determine what mitigation measures, if any, are appropriate. Recommended measures to reduce the risk of sound impact to marine species include:

- Identify sensitive areas for marine life, such as feeding, breeding, calving, and spawning grounds.
- Plan seismic surveys and offshore construction activities so as to avoid sensitive times of the year.
- Identify fishing areas and reduce disturbances by scheduling seismic surveys and construction activities for less productive times of the year, where possible.
- Maximize the efficiency of seismic surveys to reduce operation times, where possible.
- If sensitive species are anticipated in the area, monitor their presence before the onset of sound-creating activities that have the potential to produce adverse effects, and continue monitoring throughout the seismic program or construction. In areas where significant impacts to sensitive species are anticipated, use experienced observers.
- When marine mammals are observed congregating close to the area of planned activities, seismic start-up or construction should begin at least 500m away.
- If marine mammals are sighted within 500m of the proposed seismic array or construction area, postpone start-up of seismic activities or construction until they have moved away, allowing adequate time after the last sighting.
- Use soft-start procedures—also called ramp-up or slow buildup—in areas of known marine mammal activity. This involves a gradual increase in sound pressure to full operational levels.
- Use the lowest practicable power levels to image the target surface throughout the seismic surveys, and document their use.
- Where possible, use methods to reduce and/or baffle unnecessary high-frequency noise produced by air guns or other acoustic energy sources. ■

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ThoughtStream

Joe Scranton, AlTiSS Technologies

The importance and potential impact of revising API 17G

The ongoing revision of API 17G (specification for subsea well intervention equipment) includes many changes from prior editions. These changes extend beyond the added design rules and product qualification processes for hardware typically seen in design code updates. The additional sections elaborate on specific project risk analysis procedures that are interwoven with the limits and capabilities of equipment developed according to API 17G. It is within these sections where most readers will find that API 17G deviates from a traditional API specification.

Much like the layers of protection analysis (LOPA) theory used successfully in other industries, API 17G has included this approach for manufacturers and operators of intervention hardware to develop and select the appropriate "grade" of hardware based on the level of risk involved. Rather than selecting a single product to meet all requirements, this approach adds a cost-risk-benefit analysis to the equation. This allows the option of selecting conventional intervention systems such as direct hydraulic control systems for low risk intervention opportunities, while advising the use of MUX controls with SIL (IEC 61508/61511) ESD for DP intervention on live wells where hydrocarbons may be expected.

In addition to establishing protection layers, it is important to understand the capacity of the mechanical equipment, and what defines the limits. Capacity could be defined by a failure due to mechanical overload (example being vessel compensator lock-up), or fatigue due to repetitive motion and aggravated by a seawater environment. Significant effort was spent updating sections of 17G on design and qualification to ensure the methodologies were well balanced with theory, practice, and regular maintenance intervals.

As exciting as all the engineering details of all the API 17G are, the question most people want to know is: how will this affect the way I do my job? The best response is: "depends." Depends upon what your job role is. If you are a manufacturer of intervention equipment, you will find much more guidance on design and qualification requirements in one document than you ever had before.

This as a major step forward in engineering safety into every intervention campaign and reducing the role of relying on good luck for success.

However, you may be stymied by the fact that you now need better definition from the proposed application, so that bending limits, fatigue life, and other variables are properly quantified. This is where input from the operator is crucial to define design parameters.

For the operators/users of the equipment there is extensive coverage of risk mitigate processes within Clause 4 of the specification to define the steps required to de-risk a project or program and select the appropriate hardware before the campaign begins. API 17G is not a "one size fits all" code. It requires some effort to select the safest and most cost effective solution. When working with equipment, supplier's knowledge of their hardware will streamline the risk mitigation process and can help select existing technologies for some intervention scenarios.

When API 17G is released, the key to successful deployment is knowledge-sharing and training. For example, I doubt anyone would simply sit down and read ASME Section 8 to learn how to build a pressure vessel. API 17G is not as extensive as ASME Section VIII, but the point is the same; take a large design code, which at first glance appears complex and break it down into manageable and trainable elements. API 17G can quite easily be translated into training packages to improve the communication of the core message for the use of appropriate hardware for the intended application.

Once widely adopted, API 17G will allow operators to properly select and design intervention campaigns with full understanding of the capacities of the equipment they are deploying before the equipment ever reaches the vessel. This as a major step forward in engineering safety into every intervention campaign and reducing the role of relying on good luck for success. OE

Joe Scranton *is the engineering manager at AlTiSS Technologies in Houston. He has worked in various product engineering and management roles over the last 31 years with assignments ranging from reliability improvement, functional safety, E-H intervention control system design, and downhole tool design. His current role in new product development focuses on the use of Titanium and other CRAs. Scranton is a registered professional engineer in Texas.*

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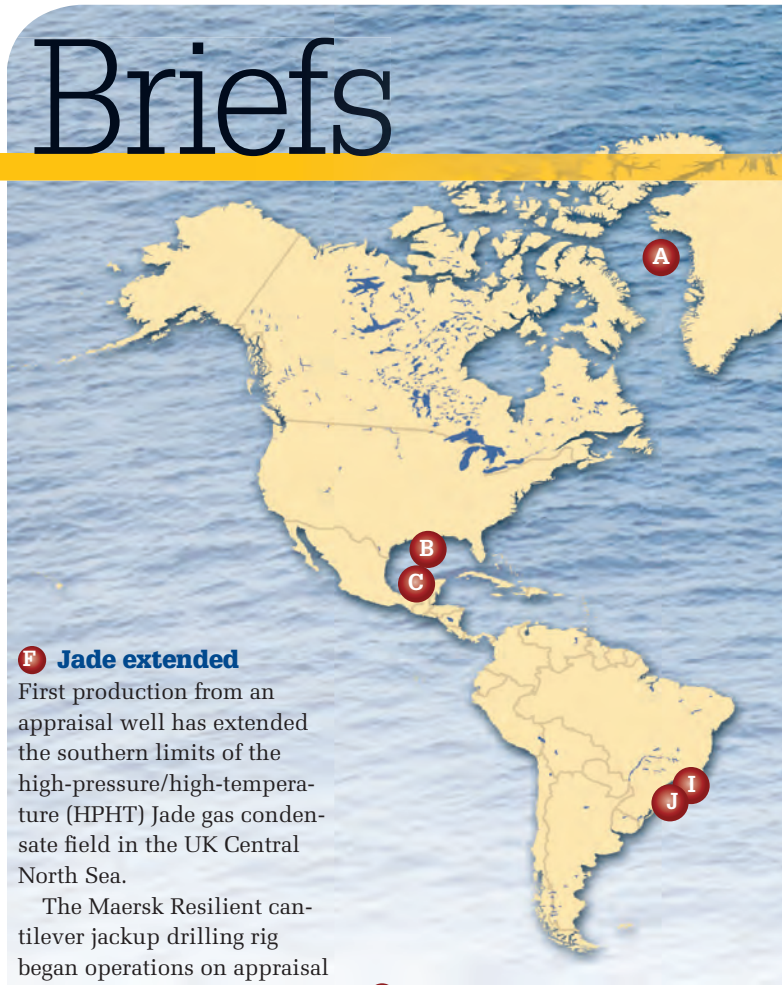
Allseas

Global Briefs



A GOA approves

Canada's National Energy Board has approved a Geophysical Operations Authorization application from TGS-NOPEC Geophysical Company (TGS), Petroleum GeoServices (PGS), and Multi Klient Invest (MKI) to conduct a 2D offshore seismic survey program in Baffin Bay and Davis Strait over five years during the open water season. MKI will be the project operator.

B Shell hits

Shell encountered more than 400ft (122m) of net oil pay at its Rydberg well, 75mi (120km), in the Norphlet play, in Gulf of Mexico Mississippi Canyon Block 525. Shell said the discovery is within 16km of the planned Appomattox development and the 2013 Vicksburg discovery.

Shell expects the resource base to be about 100MMboe, which, with the Appomattox and Vicksburg discoveries, takes the total potential Norphlet resource to over 700MMboe, Shell said. The well was drilled in 7479ft (2280m) water depth, to a total depth of 26,371ft (8038m), using Noble's *Noble Globetrotter* drillship.

C Platform completed

McDermott International has completed Ayatsil-B, one of Pemex's four drilling platforms for use in the Mexican national's Ayatsil-Tekel heavy oil field.

Located off Ciudad de Carmen in the Bay of Campeche near Cantarell, the oilfield that established Pemex as an international producer, Ayatsil is Pemex's largest-ever discovery, with 3P reserves estimated at 596MMboe.

Ayatsil-B's eight-legged, 11,535-ton substructure was floated out from McDermott International's Altamira yard in Tamaulipas, Mexico.

D Pil estimates increased

VNG Norge has discovered oil on the Bue well, in production license (PL) 586, offshore Norway, and increased its resource estimate for the nearby Pil discovery, in the same license.

The combined resource of both finds has been estimated at 80-200MMboe by partner Faroe petroleum, which says both fields could be tie-back candidates to the nearby Njord platform.

The Bue 6406/12-3 A wildcat well encountered an 18m oil column in sandstones from the Rogn formation, with reservoir quality varying from good to very good. VNG also drilled appraisal well 6406/12-3 B on the 6406/12-3 S (Pil) oil and gas discovery, increasing Pil's estimates to 8.8-21.1MMcu m of recoverable oil and condensate, as well as 2.7- 6.1 billion cu m of recoverable gas.

E Further Johan Castberg delays

Statoil announced further delay in developing the Johan Castberg project, postponing final concept selection on the Barents Sea project until 2015. Statoil said it found less oil than expected. The Barents Sea project is in PL532 and comprises the Skrugard, Havis, and Drivis discoveries, totaling 400-600MMboe.

F Jade extended

First production from an appraisal well has extended the southern limits of the high-pressure/high-temperature (HPHT) Jade gas condensate field in the UK Central North Sea.

The Maersk Resilient cantilever jackup drilling rig began operations on appraisal well 30/2C-J12Z, located in a structure south of the primary Jade field, in August 2013. Its target was HPHT Triassic sandstone.

G Edradour advances

Total decided to move forward with its Edradour subsea development in Block 206/4a, in about 300m water depth, 75km northwest of the Shetlands. Edradour, costing about £340 million, will tie-in to Total's Laggan-Tormore development, with first production targeted Q4 2017.

Total also acquired a 60% interest in the nearby Glenlivet discovery, operated by DONG Energy. Glenlivet is also expected to be tied back through the Laggan-Tormore infrastructure. Total said Edradour and Glenlivet would add more than 65MMboe reserves to the area and form part of a "new strategic hub in the West of Shetland area."

H Licensing round launched

Ireland's Government launched the 2015 Atlantic Margin Oil and Gas Exploration Licensing Round and a new offshore oil and gas production taxation regime, including an increase in the top tax rate.

The new round, which will close September 2015, covers all of Ireland's major Atlantic basins: Porcupine, Goban Spur, Slyne, Erris, Donegal and Rockall. A two-year licensing option will be offered, which could be converted into a 15-year frontier exploration license.

I Production begins

Brazilian independent OGPar (Óleo e Gás Participações SA), formerly known as OGX, started production on the third well in the Tubarão Martelo field, 58mi off Rio de Janiero.

The well, TBMT-2HP, is located in the field, and is comprised of blocks BM-C-39 and BM-C-40. Operations on a fourth well will commence after its upper completion, OGPar said.

J Maersk retreats

Maersk Olie og Gas (Maersk Oil) said it will no longer pursue growth or operatorship for its business in Brazil, citing a US$1.7 billion impairment on its Brazilian assets and disappointing appraisals.

In 2011, the Danish company acquired acreage in the Campos basin's Polvo, Wahoo and Itaipu fields for $2.4 billion. Maersk Oil said it will unload its 40% interest in Polvo to Brazilian operator HRT Oil & Gas. The remaining assets, the Anadarko Petroleum-operated Wahoo and the BP-operated Itaipu, will be written down to $600 million.

K Woodside agrees

Australia's Woodside finalized an agreement with Chariot Oil & Gas to farm in to the prospective Doukkala basin, offshore northwest Morocco.

Under the agreement, Woodside acquires an initial 25% interest in the Rabat Deep Offshore permits I-VI. The agreement includes an option to acquire an additional 25% and operatorship, for a capped well carry obligation. The agreement is also subject to required government approvals.

Permits I-VI are undrilled and cover 10,782sq km, 50km offshore, in 150-3600m water depths. The Rabat Deep permits are nearby Woodside's Canary Islands acreage position.

L Buried Hill Africa farms in

African Petroleum Corp. has agreed on a farm-out deal with Buried Hill Africa on Block CI-509 offshore Côte d'Ivoire (Ivory Coast), West Africa.

Buried Hill will get a 10% interest in the block in return for funding 21.1% of the cost of the next exploration well and an additional cash payment to African Petroleum Corp., representing 10% of past costs incurred.
African Petroleum Corp. will remain operator.

M Sasol plans for GTL

Sasol has announced a joint pre-feasibility study for a large-scale gas-to-liquids (GTL) plant, which will be based on gas from the Rovuma Basin in northern Mozambique.

The study, which is being conducted in conjunction with Mozambique's national oil company, Empresa Nacional de Hidrocarbonetos, and Italian multinational, Eni, will assess the viability and benefits of such a plant to the region.

Eni is operator of the block, called Area 4, in the deep waters of the Rovuma Basin, which is estimated to hold up to 85Tcf of gas.

N Eni acquires

Eni has gained operatorship and a 40% interest in exploration right permit 236 (ER236) off the eastern coast of South Africa from Sasol.

Under the terms of the agreement, Eni has acquired 82,000sq km of unexplored acreage in the Durban and Zululand basins within the Kwazulu-Natal province. The financial terms were not disclosed. Sasol originally acquired the 3-year permit in November 2013 by the Petroleum Agency of South Africa.

O Dragon Oil expands

Dragon Oil signed a contract for Block 19 East Zeit Bay, offshore the Gulf of Suez, Egypt, its first 100%-operatorship block outside of Turkmenistan.

Dragon Oil's main producing Turkmeni asset is the Cheleken contract area, offshore in the eastern section of the Caspian Sea.

Between 8-10 wells are still due to be completed on the firm's Turkmeni assets by the end of the year, helping to increase production to 87,000-90,000bo/d compared to the 73,440bo/d average seen in 1H 2014 (73,600bp/d in 1H 2013).

P Berkut commissioned

Commissioning operations started on the 200,000-ton, 144m tall, Berkut platform on the Arkutun-Dagi field, part of the Sakhalin-1 project, Russia.

First oil for Arkutun-Dagi is expected YE 2014, with peak production in 2017. At that point, it will contribute 4.5 million tons of oil per

year to the Sakhalin-1 project's overall production of more than 10 million tons of oil (by 2018). Forty-five wells will be drilled- 28 oil producing, 16 water-injection wells, and 1 well for cutting re-injection- with a peak daily flow of 12,000tons. Berkut was built at Daewoo Shipbuilding and Marine Engineering's Korean yard and designed for subarctic conditions.

Q CNPC hits hydrocarbons

China National Petroleum Corporation (CNPC) found hydrocarbons on the Zhongjannan exploration project, off the Paracel or Xisha Islands, in the South China.

Drilling on two wells, using the deepwater *HYSY-981* semisubmersible drilling rig, operated by China Oilfield Services Limited (COSL), completed 15 July.

CNPC said oil and gas shows were found, but gave no more information, adding that a comprehensive assessment will be carried out on the geological and analytical data collected.

The rig will now be relocated to operations on the LingShui Blocks the off Hainan Islands, said COSL.

R Dua produces

Oil production started at the Premier Oil operated Dua oil project on 11 July from three wells, 40 years after the field was discovered. Production from the Dua wells is estimated to average 8000 bo/d for the first 12 months of production. Sufficient oil and gas handling capacity is available on the *Chim Sao* FPSO to accommodate both *Chim Sao* and Dua at full production.

S Pegaga gas 'substantial'

Appraisal drilling and testing confirmed the Pegaga discovery, in 109m water depth, in Block SK320 offshore Malaysia as a substantial gas discovery.

Pegaga-2 was drilled to a total depth of 2685m and confirmed an 850m gas column. Testing of the main gas-bearing zones produced flow rates of 30-50MMcfd of good quality gas with condensate.

A third discovery, Sirih-1, part of a drilling campaign targeting carbonate pinnacles within Block SK320, was also confirmed by operator Mubadala Petroleum. Sirih-1 was drilled to a total depth of 3000m into the main target reservoir and penetrated a 293m gas column.

T Ichthys launched

Japan's Inpex Corp. launched the 336m-long hull of its Ichthys FPSO from the dry dock of the Daewoo Shipbuilding and Marine Engineering yard in Okpo, South Korea, July 6. The project's next major milestone would be the turret installation. The Ichthys LNG project is scheduled to start production by the end of 2016, with gas sourced from the Ichthys gas and condensate field in the Browse basin off Western Australia.

U Toro-1 well drilled

Woodside announced that the Toro-1 exploration well in permit WA-430-P has intersected approximately 150m gross gas and 65m net gas within the Mungaroo Formation target.

The Toro-1 well was drilled to a total depth of 3724m, referenced from the rig rotary table, by the Transocean *Deepwater Millennium* drillship. Toro is in Western Australia's Exmouth Sub-Basin and is within 22km of Woodside's existing Ragnar-1A discovery.

V West Seahorse gets MPF backing

Carnarvon Hibiscus' West Seahorse project in the Gippsland basin, offshore southeastern Australia, has been granted access to Federal Government Major Project Facilitation services.

Deputy Prime Minister and Minister for Infrastructure and Regional Development Warren Truss said Carnarvon Hibiscus, a wholly-owned subsidiary of Hibiscus Petroleum, will now have access to MPF services to help advance the project.

West Seahorse is in Block Vic/P57, offshore Gippsland. It is due to be produced via two production wells through a mobile offshore production unit, the GSP Britannia, which is undergoing work in Tuzla, Turkey to reactivate ABS class and enable long term use on West Seahorse.

Oil offloading will be via a catenary anchor leg mooring buoy and offloading hose, to a floating storage and offloading vessel to tankers. First production is due 2Q-3Q 2015.

W UOD supplies PTTEP rig

UMW Oil & Gas Corp.-subsidiary UMW Offshore Drilling (UOD) announced it will provide Thailand's PTTEP International drilling rig services for the Block M-3 appraisal drilling campaign 2014, offshore Myanmar.

Under the contract, UOD will supply the UMW NAGA 5, its latest jackup drilling rig, which is currently under a drilling contract in the Philippines with NIDO Petroleum, for the project. The contract is for five firm wells, (about 250 days, excluding mobilization and demobilization), and may be extended for one optional well). The contract is worth about US$51.3 million for the firm wells. The rig is expected to be mobilized to Myanmar in August.

Contract Briefs

AMEC to design Sea Lion TLP

AMEC won a front-end engineering and design contract for a tension leg platform (TLP) at Premier Oil's Falklands Sea Lion development.

AMEC will handle the design of the 30,000-tonne TLP, including the hull, topsides and drilling facilities, with the potential to provide continued support to Premier.

Phased production is planned from a central TLP, with future subsea tiebacks. The TLP will contain drilling, topsides well processing facilities and utilities with oil export being undertaken via a separate FSO unit.

Macgregor wins Kraken contract

Macgregor has secured contracts from Malaysia-based Bumi Armada Berhad to supply equipment for the North Sea Kraken FPSO conversion project and three ice-class support vessels.

Macgregor will supply a Pusnes offloading system for the Kraken FPSO. Macgregor is also supplying electro-hydraulic windlass/mooring winches, capstans, tugger winches and storage reels, along with anchor handling/towing winches with a 120-tonnes line pull and 200-tonne brake holding capacity, for three 80m-long ice-class vessels destined for the Caspian Sea.

WGK on TEN project

Wood Group Kenny (WGK) won an engineering services contract to support Tullow Oil's Tweneboa, Enyenra and Ntomme (TEN) project, offshore Ghana.

TEN will be comprised of up to 24 development wells, connected through subsea infrastructure to an FPSO. WGK will provide subsea, umbilical, risers, and flowlines (SURF) engineering services.

The Tweneboa, Enyenra and Ntomme oil fields are in the deepwater Tano area, about 30km from the producing Jubilee field. First oil from the TEN fields is scheduled for mid-2016, and the nominal production capacity of the FPSO is 80,000bo/d.

Saipem FPSO extended

Petrobras awarded Saipem a four-year extension to the Cidade de Vitória FPSO lease contract at Petrobras' Golfinho field, in Brazil's Espirito Santo Basin, as well as a contract for modification and upgrading of the leased FPSO vessel. The total value of the two contracts is approximately US$450 million.

The modification works are to increase the produced water treatment capacity and allow the connection of two additional gas wells with a high level of condensates by 1Q 2016.

In Angola, Saipem has been awarded by Sonangol P&P a two-year extension of the Gimboa FPSO lease and operation contract in Block 4/05, where it has been operating since 2006. The contract is extended to 1Q 2017 and the two-year extension has a value of approximately $150 million.

Aibel signs Statoil deals

Norway's Aibel has signed a string of contracts with Statoil. The firm has agreed on a framework agreement covering the supply of personnel to Statoil's projects in Norway and abroad, starting 1 August, for one year. Aibel also won a contract for the hook-up of new living quarters to the Oseberg C platform. The contract has an estimated value of about NOK 125 million. The project, called the Oseberg C Continuous Drilling (LQ Extension) project, covers engineering, procurement, construction, and installation.

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Over 24,000 offshore wells need to be drilled through 2020

Douglas-Westwood's Matt Cook examines the world outlook for drilling new offshore development wells out to 2020.

Douglas-Westwood's (DW) new *World Development Drilling & Production Forecast* states that in 2013 offshore oil and gas development wells drilled totalled just over 3000, but in 2020 well numbers will need to exceed 3900. These are required to meet global oil and gas demand, which is set to grow 17% by 2020.

Global oil consumption rose 8% from 2004 to 2012, while natural gas consumption rose 24% over the same period (Source: BP's 2013 Statistical Review). Many countries are seeking cleaner energy generation and are moving away from coal and oil to natural gas. This is especially the case in Asia where expanding economies necessitate a larger gas supply. Also, natural gas will become more available – with liquefied natural gas (LNG) technology continuously evolving and the necessary infrastructure being developed.

Maersk Intrepid at Westcon Yard, Norway.
Photo from Maersk Drilling.

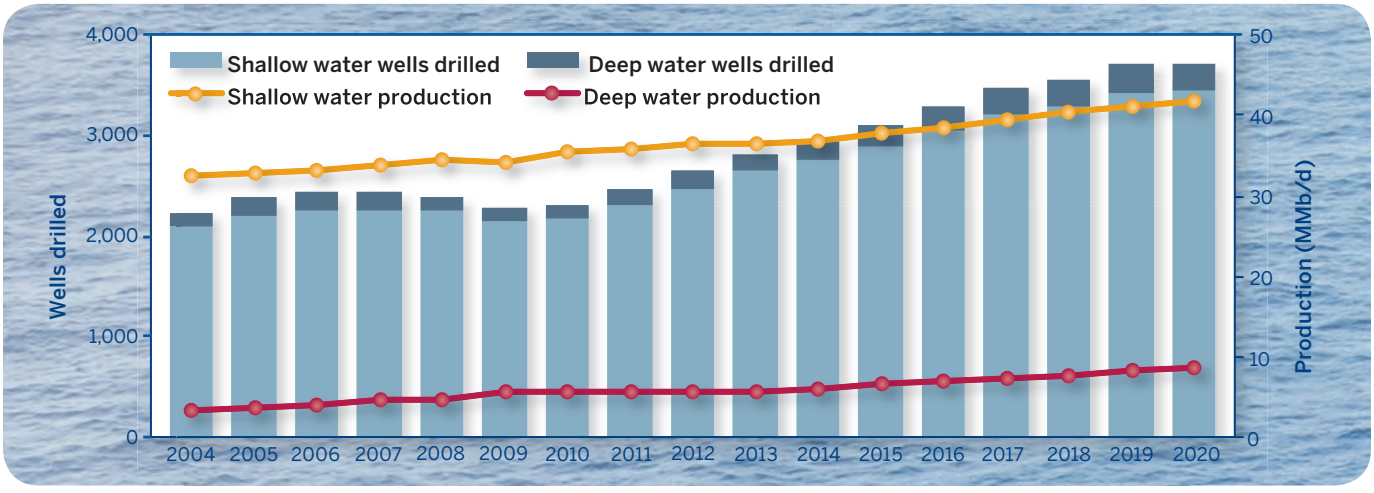
Traditionally productive offshore provinces are in decline and face a variety of futures. Shallow-water oil production is struggling for growth despite high levels of investment – well completions will rise 17% by 2020 for just 4% output growth.

Africa will be a continent of mixed futures in oil and gas production. West Africa's deepwater fields will continue to go from strength to strength while North Africa's political instability will likely hinder offshore exploration and developments. East Africa has recently undergone a great amount of exploration and ENI is now in the early phases of developing gas fields in Mozambique. Growth in Mozambique and Tanzania onshore and offshore gas could potentially be driven by export opportunities to South Africa and Southeast Asia due to little domestic demand.

West Africa will sustain strong growth offshore as IOC-led projects continue to flourish. Nigeria plans to introduce new petroleum laws in the near-term to create a less-risky operating environment. Angola's deepwater production is set to ramp up as its shallow water sector matures. Pre-salt discoveries in recent years are now showing promising early production, suggesting they could be as productive as their equivalents across the Atlantic. These factors will see African deepwater well completions rise over 89% by 2017.

Across the South Atlantic, offshore Brazil will continue to dominate Latin American production. With a host of FPS projects planned for its already prolific Campos and Santos basins – boosting deepwater well completions by nearly 54% by 2020. Considering this, DW predicts offshore production will rocket to just under 3300b/d by 2020, a 48% increase from 2013 levels.

Wells drilled and production by water depth: shallow (<500m) and deep (>500m)



Source: Douglas-Westwood *World Development Drilling & Production Forecast 2004-2020.*

Quick stats

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

New discoveries announced

Depth range	2011	2012	2013	2014
Shallow (<500m)	105	75	70	29
Deep (500-1500m)	25	24	19	7
Ultradeep (>1500m)	18	37	32	3
Total	**148**	**136**	**121**	**39**
Start of 2014 date comparison	151	135	98	-
	-3	1	23	39

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

Reserves in the Golden Triangle

by water depth 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	15	603.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	45	13,235.25	18,090.00
United States			
Shallow	23	105.55	352.00
Deep	20	1,510.11	1,654.57
Ultradeep	32	4,300.50	4,290.00
West Africa			
Shallow	168	4,572.47	22,447.05
Deep	50	5,886.50	7,170.00
Ultradeep	17	1,805.00	3,210.00
Total	**386**	**34,633.63**	**60,788.62**
(last month)	(370)	(34,586.08)	(60,098.62)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1238	47,759.96	805,426.92
(last month)	(1255)	(48,376.31)	(827,387.48)
Deep	161	12,580.98	97,909.77
(last month)	(163)	(12,591.98)	(99,259.77)
Ultradeep	109	19,880.75	57,257.00
(last month)	(110)	(20,435.75)	(57,657.00)
Total	**1,508**	**80,221.69**	**960,593.69**

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	40,348	(41,407)
Planned/ possible	24,740	(24,640)
	65,088	(66,047)
8-16in.		
Operational/ installed	77,889	(77,988)
Planned/ possible	49,475	(50,014)
	127,364	(128,002)
>16in.		
Operational/ installed	89,810	(89,687)
Planned/ possible	48,765	(49,948)
	138,575	(139,635)

Production systems worldwide

(operational and 2014 onwards)

Floaters		(last month)
Operational	278	278
Under development	41	41
Planned/possible	335	335
	654	654
Fixed platforms		
Operational	9,273	(9,378)
Under development	129	(123)
Planned/possible	1,391	(1,398)
	10,793	(10,899)
Subsea wells		
Operational	4,481	(4,511)
Under development	408	(436)
Planned/possible	6,398	(6,375)
	11,287	(11,322)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow	10,494.57	6,015.73	23,658.35	45,585.00	36,569.77	33,117.01	44,387.07
(last month)	(6,013.67)	(23,663.26)	(47,785.52)	(36,900.08)	(32,485.93)	(46,422.29)	(31,308.88)
Deep	2791.02	484.30	4,598.44	5,843.45	3,579.44	5,215.54	10,597.09
(last month)	(2,817.87)	(484.30)	(4,598.44)	(5,860.74)	(4,317.40)	(5,401.84)	(9,904.55)
Ultradeep	737.15	2,932.94	2,817.43	1,932.29	5,193.17	12,634.64	7,398.10
(last month)	(737.15)	(2,932.94)	(2,817.43)	(1,932.29)	(5,193.17)	(13,935.16)	(6,723.10)
Total	**11,555.90**	**29,088.59**	**55,014.87**	**46,360.51**	**43,905.62**	**64,254.25**	**50,769.31**

14 July 2014

However, this is a low-case view, as Petrobras' huge debt and delays to newbuilds means that their deepwater plans are unlikely to be carried out in their entirety.

Elsewhere in Latin America, Mexico's 2013 energy law reforms will undoubtedly lead to a host of opportunities for IOCs – with discoveries in the deepwater Perdido fold belt as well as a shallow-water production agreement with the US. A significant production increase is not likely to be seen until at least 2018-19, however, due to licensing rounds not being held until the end of 2015.

The biggest export opportunities for Pacific-adjacent Latin American markets are expected to lie in the prospering Southeast Asia economies. China is the most significant of these as it continues to seek to boost domestic production as well as create new import opportunities with investment abroad – in order to fuel one of the world's largest economies. Domestically, declining conventional-based onshore output will be rescued by heavy investment into unconventionals – most notably coal bed methane (CBM) production as shale oil and gas struggling for growth in the medium term. Offshore, CNOOC has ambitious plans for deepwater gas projects alongside a shallow water sector that has seen strong growth in recent years. Historically, CNOOC has often met production targets, therefore, DW expects the pressure of growing domestic demand will ensure that the medium term will be no different. This will be achieved by a 54% increase in offshore well completions by 2020, resulting in a combined output of 1300boe/d – up 56% from 2013 levels.

Japan and South Korea, important regional importers, represent attractive opportunities due to high local gas prices. The rest of Asia-Pacific (APAC) are expected to capitalize on this with gains in gas production driving LNG exports. Leading the way will be Shell and Petronas' FLNG plans. Petronas will be placing their PFLNG1 facility on Malaysia's Kanowit field – while Shell's facility will produce at Australia's Prelude field – going some way to help fill Australian LNG capacity and achieving Australia's goal to become the world's largest LNG exporter.

Shallow-water gas drilling will increase in Southeast Asia as markets look to take advantage of export opportunities to Japan and South Korea. Thailand and Vietnam will account for much of this drilling due to high decline rates and low well productivity. Thailand alone drilled 410 offshore wells in 2013 to maintain offshore gas production at just under 700,000boe/d.

Over the border in Russia, despite declining output from the mature onshore Western Siberia and Urals-Volga regions (which the EIA state in 2012 accounted for 85% of production) output will be maintained by greenfield projects both onshore and offshore. Therefore, DW expects Russia's production to plateau in the 2020s, with an average annual growth of 1.4%. DW expects the three-phase Sakhalin project to contribute to an offshore gas production of 0.7MMboe/d. This will be part of to 139 wells being completed in Russian waters by the end of the decade, about a third of which will be in the controversial Prirazlomnoye field – the area where 30 environmental activists were arrested in September 2013.

Western Europe will continue to rely on imported Russian gas into the 2020s as mature offshore fields (which typify the region) struggle for growth. With many IOCs planning investment in UK offshore fields through EOR, deepwater plays and downstream infrastructure upgrades, DW predicts that production will rally slightly, to around 1.5MMb/d by 2017, requiring 724 well completions between now and then. The necessary high levels of expenditure are unlikely to be sustained in the long term due to the UK's offshore maturity, therefore DW expects a resumption of

decline towards the end of the decade. On the other side of the North Sea, Statoil will attempt improved recovery from brownfield projects. Along with project startups in the large Johan Sverdrup and Goliat fields, the number of well completions should be sustained at about 180/yr for the rest of the decade. DW expects these projects will see Norway break from the mold of other mature Western European producers and sustain gas production into the next decade.

Some of the biggest growth in drilling markets will be seen in the Middle East as NOCs invest billions of dollars redeveloping maturing fields – with 44% growth by the end of the decade.

Qatar is expected to boost production from the offshore North field, the world's largest non-associated gas field. However, the short-term success of this is dependent on the lifting of a moratorium put in place to shift investment into downstream sectors.

The UAE will look to ramp up production in both oil and gas, spending US$60 billion and $25 billion, respectively. The success of this redevelopment now rests solely with UAE's ADNOC – the NOC recently took control of all IOC assets in the country. Saudi Arabia, currently the world's largest oil producer, will see offshore oil well completions rise 45% by 2020 as the country looks to increase offshore output to 4.4MMboe/d by 2020. With several projects due to come onstream in the Arabian Gulf, Saudi offshore well completions will rise to 211 in 2020 from 145 in 2013.

In the US Gulf of Mexico well completions have recovered since 2010. This was caused by the lifting of the moratorium put in place following the Macondo accident and sustained high oil prices. DW predict that with rallying gas prices, well completions will steadily increase up to a peak of 275 in 2019.

Taking stock, DW forecasts of global growth is good news for drilling contractors and oilfield services, as increasing field maturity will require more and more wells to be drilled to achieve smaller gains in production. Indeed, the DW production forecast requires a 31% offshore well completion increase from 2013-2020 for only a 19% rise in global offshore oil and gas output. OE

Matt Cook *joined DW after graduating from Imperial College's Royal School of Mines with a Geology BSc. Since, Cook has conducted research into the upstream oil and gas sector. Using skills in data modelling, country-specific knowledge of the upstream sector and aided by past experience with an E&P company, Cook coordinated the creation of DW's new Development Drilling and Production Forecast as lead author.*

The new quarterly issue (Q2) of Douglas-Westwood's *World Development Drilling & Production Forecast 2004-2020 (DWD&P)* has been released. Major changes have been seen in the forecasts for Egypt & Kazakhstan. The report now includes forecasts for Germany & Poland. Through to 2020 and utilizing a proprietary methodology, DWD&P provides data analysis on 53 key countries representing an estimated 96% of global onshore and offshore hydrocarbon production. Based on detailed models, the report examines each country in turn and includes a summary of hydrocarbon potential and sensitised production outlook, with associated development drilling requirements segmented into oil & gas, onshore & offshore, which is divided into deep and shallow water.

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	104	101	3	97%
Jackup	422	379	43	89%
Semisub	192	164	28	85%
Tenders	33	22	11	66%
Total	**751**	**666**	**85**	**88%**

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	29	29	0	100%
Jackup	93	77	16	82%
Semisub	28	25	3	89%
Tenders	N/A	N/A	N/A	N/A
Total	**150**	**131**	**19**	**87%**

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	14	12	2	85%
Jackup	116	109	7	93%
Semisub	38	29	9	76%
Tenders	24	15	9	62%
Total	**192**	**165**	**27**	**85%**

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	26	26	0	100%
Jackup	9	6	3	66%
Semisub	38	38	0	100%
Tenders	2	2	0	100%
Total	**75**	**72**	**3**	**96%**

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	49	49	0	100%
Semisub	46	43	3	93%
Tenders	N/A	N/A	N/A	N/A
Total	**96**	**93**	**3**	**96%**

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	107	94	13	87%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	**111**	**98**	**13**	**88%**

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	32	31	1	96%
Jackup	24	20	4	83%
Semisub	20	16	4	80%
Tenders	7	5	2	71%
Total	**83**	**72**	**11**	**86%**

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	24	24	0	100%
Semisub	19	10	9	52%
Tenders	N/A	N/A	N/A	N/A
Total	**44**	**35**	**9**	**79%**

Source: InfieldRigs

18 July 2014

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

Intervention allies

Sarah Parker Musarra spoke with FTO Services' Vidar Sten-Halvorsen to learn more about the new *Island Performer* intervention vessel, a product of the joint venture between FMC Technologies and Edison Chouest Offshore.

With FMC Technologies' subsea experience and technology, and marine transport company Edison Chouest's strong presence in the Gulf of Mexico and Brazil, a partnership appeared to be a natural fit.

"Rather than compete against each other, it would be much better to join forces," Vidar Sten-Halvorsen, formerly with FMC Technologies, says.

In 2012, the two companies embarked on a well intervention services joint venture, known as FTO Services. Sten-Halvorsen is now the technical director.

'Ready for international waters'

Formally named in June and delivered to Island Offshore less than one month later on 8 July, *Island Performer* is designed for riserless light well intervention (RLWI) and inspection, repair and maintenance services. The design is based on another Ulstein-built vessel: *Island Constructor*, of the shipbuilder's SX121 design.

Scan this page with the Actable app on your smart phone to see a video from shipbuilder Ulstein outlining the development of *Island Perfomer*.

Built in 2008, the vessel has worked exclusively in the North Sea, performing well intervention for companies including BP Exploration, Statoil and Premier Oil UK.

With FTO focused on waters outside the North Sea, the newbuild *Island Performer* required specialized design and technology to serve those other markets.

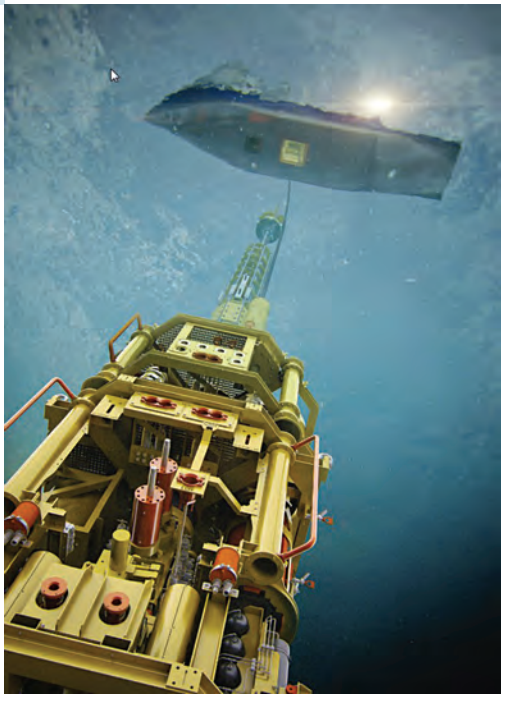
"It has [been improved upon] and has been designed with more dedicated functions that will take it into international waters," Sten-Halvorsen says.

The vessel itself is larger to accommodate the equipment necessary to venture into deeper waters. The *Island Performer* measures 130m, about 10m longer than its predecessor. The reels, operations deck and tank storage have also been enlarged. Additionally, the vessel, an Ulstein X-bow design, features a 140-ton modular handling tower and a 250-ton active heave compensated crane. The ROV launch window has been significantly enhanced with a dedicated moon pool in the center line of the vessel, allowing deployment and recovery of the ROV in higher sea states.

It includes an acoustic doppler current profiler (ADCP) array on the bottom of the hull, similar to what was installed on *Island Constructor* after operations West of Shetland for BP, where subsea currents wreaked havoc with umbilicals, ROVs and wireline logging tool deployment.

FTO Services solicited feedback from its clients and offshore crews while designing the vessel and its components, and Sten-Halvorsen says that acid stimulation and fluid placement were mentioned as issues in the three regions the company is pursuing. The firm has tried to address these concerns in *Island Performer*.

"The benefit here [with *Island Performer*] is that you can go in and diagnose the wells because we have intervention capabilities," he says. "We can go in, log them and understand what the issues are. You have a better diagnosis of the well and you can also then document the effects much better. You can go in after treatment and document before and after assessments of the quality and production of the well."



New 2000m rated deepwater stack, designed without a need for guidepost orientation.
Photo from FTO Services.

The RLWI deepwater stack and the 'platform-less future'

With rig rates continuing to be one of the main sources of expenditures in offshore exploration and production, FMC Technologies says it is pursuing a "platform-less future" by expanding its subsea offerings. Also, FTO Services Managing Director John Griffin said that rigs are not primarily designed for intervention, whereas vessels can be. "Based on field experience, vessel-based interventions are safer, more efficient and less costly when compared to a rig. The new RLWI deepwater stack solution can deliver these benefits while supporting 80% of the work scope associated with conventional intervention operations," Griffin said in May.

Sten-Halvorsen says the *Island Performer* is a "response" to FMC Technologies' vision.

"Subsea wells will be much more accessible when you have the availability, capacity, and intervention equipment," he says. "For that future vision, you need this type of vessel with the capability of performing frequent interventions to

***Island Performer* is the first product of the FMC Technologies and Edison Chouest joint venture.** Image from FTO Services.

***The Island Constructor*, whose design was the basis for *Island Performer*.** Photo from Ulstein.

achieve the same kind of production performance that surface wells have today."

FMC Technologies is delivering its first RLWI deepwater stack to FTO Services 4Q 2014 for deployment from *Island Performer*. It is designed to operate in water up to 2000m and in pressures of 10,000psi.

It is the fourth such stack that FMC Technologies has built, with the first generation created from an adopted riser stack, Sten-Halvorsen explains.

Moving into deeper water, the typical deployment method, using guidelines, is not possible. The stack has been designed without the need for guide post orientation and downlines for deploying the upper lubricator section. The umbilical is low-profile with all hydraulic power and accumulation performed on the subsea stack, removing the need for large hydraulic umbilicals, which are difficult to handle in deeper water and problematic in high currents. The umbilical termination is self-engaging when it reaches the stack, requiring minimal interaction by the ROV.

FTO Services said that the designers of this iteration were mindful of the five-year blowout preventer recertification program, so the structure has been simplified, and parts can be changed out or repaired easily.

Diving deeper into the idea of a platform-less future, the *Island Performer* is also designed to be able to conduct plug and abandonment operations by placing the cement to plug the reservoir.

Sten-Halvorsen calls the vessel "superior," adding: "Everything is done here to prepare for operations. Everyone will be working in a safe environments and understands what the costs are. It is very different from a vessel of opportunity, where you have to improvise and put everything together for the first time."

Similar to the FTO Services joint venture, Fugro, of The Netherlands, and Malaysian oilfield services company Bumi Armada Berhad announced in September 2013 they were forming a JV targeting well services. Fugro will hold 49% interest with Bumi Armada holding the remaining 51%. The venture marks Fugro's first foray into well services.

The partnership is now focused on its next project, a new vessel built for construction and intervention operations. The vessel will be built at Edison Chouest Offshore's Louisiana shipyard in order to be compliant with the US Jones Act, which states that a commercial vessel transporting between US ports must be built and operated by US citizens.

The newbuid will be designed to perform deepwater plug and abandonments, top hole drilling, and both riser-based and riserless intervention. The vessel will measure 492ft (146m) long. Griffin says this project is notable because no other offshore supply vessel of this class has been built in the US before. OE

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Tuesday, Aug. 12

Workshop 1:00-5:00 PM

7:00 AM

Golf Tournament at Moody Gardens
Sponsored by: OCEANEERING

Navigating 17G
Technical Advisors:
Khoa Pham, Barney Paternostro, LLOG; Dan Viela, Oceaneering

Summary of Requirements; Clause 1
a. All-encompassing specification covers most aspects of well intervention.
b. Review flowchart
Joe Scranton, AITiSS Technologies

System Requirements / Documentation; Clause 4
a. System Engineering (4.4)
Russell Hoshman, BSEE
b. Modes of Operation (4.8)
c. Safety Strategy (4.13)
Lynard Carter, BSEE
Russell Hoshman, BSEE

Coffee Break in Exhibit Hall
Sponsored by: AkerSolutions

Functional Design Requirements; Clause 5 & Annex
a. Subsea Test Tree Assembly; Thru-BOP (5.7)
b. Well Control Package; Open Water (5.20)
c. IWOCS; E-H, MUX, Hybrid (M.2.3)
Khoa Pam and Dan Vela, Oceaneering

Operational Examples; Annex J
a. Barrier Selection (J.2.2)
b. Barrier Testing (J.3)
c. Risk Evaluation (J.4)
Mike Hess, Shell

Product Qualification; Annex K, L
a. Well Barrier Qualification (K.3 & L.3)
b. Legacy Product Adoption
Barney Paternostro, LLOG
Joe Scranton, AITiSS Technologies

5:00-7:00 PM

Opening Night Reception
Sponsored by: CROSS GROUP, BAKER HUGHES, TETRA

Wednesday, Aug. 13

7:30-8:00 AM

Continental Breakfast in Exhibit Hall

8:00 AM

Introduction and Opening Remarks
Ray Stawaisz, Chevron

8:10-8:30 AM

Keynote
Dissection of The Intervention Market – Addressing Technology Needs and Niche Application for Subsea Development
Owen Kratz, President and Chief Executive Officer, Helix

8:40-9:00 AM

Keynote
API Overview: The Impact of Regulations on Subsea Wells, including HPHT
Holly Hopkins, Senior Policy Advisor, API

Session I 9:00AM- 10:20 AM

Technology
Session Chairs:
J.J. Duenas, BP;
Neil Crawford, Blue Ocean Subsea

Micro-Light Well Intervention: Doing More with Less
Bill Siersdorfer, OneSubsea

Mechanically Connected Risers from Mechanically Connected SCR's
Alpha Mahatvaraj, GMC Inc.

High Resolution Subsea Laser Scanning for Inspection and Maintenance
Mark Hardy, 3D at Depth LLC

Reducing Risk and NPT in Casing Cutting and Pulling Operations Using an Innovative Resettable Casing Spear
William A. Hered,Baker Hughes

Coffee Break in Exhibit Hall
Sponsored by: AkerSolutions

10:20-10:40 AM

Session II 10:45AM- 12:00 PM

Purpose Built versus Vessels of Opportunities - Panel Discussion
Session Chairs:
Dave Medeiros, Advanced Undersea Vehicles and Systems; Colin Buchan, Shell; Jim McAllister, Shell

John Griffin, FTO Services

Eric Galerne, Oceaneering International

Ultra Deepwater Riserless Well Intervention and Vessels of Opportunity
Neil Crawford, Blue Ocean Technologies

RLWI – Purpose Built Vessels and Vessels of Opportunity
Phil Bosworth, Helix Well Ops (UK) Ltd

HOSTED BY:

Chevron

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PRESENTED BY: OE

5:00-7:00 PM

Reception in Exhibit Hall
Sponsored by: HALLIBURTON

7:00-8:30 PM

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

Thursday, Aug. 14

Continental Breakfast in Exhibit Hall
7:30-8:00 AM

8:05 AM

Introduction and Opening Remarks
Colin Johnston, Helix WellOps Inc.

8:10-8:30 AM

Keynote
Offshore Energy Trends
Mike Haney, Director, Douglas Westwood

Session V 8:30-10:00 AM

Case Studies
Session Chairs:
David Wright, Wrights Well Control; Roberth Keith; Ron Hughes, TETRA Technologies

RLWI Operations on Three Continents
Oliver Willis, Helix Well Ops UK

One Control System for Any Well Control Application
Kristian Stadsøy Grjotheim, Aker Solutions

Successful Use of Intervention Rig in Deepwater Riser-Based & Riserless P/A
Robert B Langston, Schlumberger

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

10:00-10:25 AM

Coffee Break in Exhibit Hall
Sponsored by: AkerSolutions

Session VI 10:30 AM-12:00 PM

Identifying and Closing Technology Gaps - Part I
Session Chairs: Jason Leath, The Cross Group; Tony Ryan; Conoco Phillips Global Completion, Intervention & Integrity Group

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

Session III 1:30-3:00 PM

GoM RLWI challenges and lessons learned
Brian Stiels, Subsea

Riserless Deep Abandonments in Viosca Knolls
Steve Ashcraft, Anadarko

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

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

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

Lunch in Exhibit Hall
12:00-1:25 PM

Session IV 3:30-5:00 PM

Subsea Well Operations – Aligning Regional Requirements
Kurt Hurzeler, Helix Well Ops US.

Subsea Completions & Well Interventions – Performance Management and Decision Quality
Scott Herman, Chevron

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

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

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

3:00-3:25 PM

Coffee Break in Exhibit Hall
Sponsored by: AkerSolutions

Session VII 1:15-2:45 PM

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

The Impact of 20k and Higher on Interventions
Brian Skeels, FMC Technologies

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

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

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

Lunch in Exhibit Hall
12:00- 1:10 PM

Effect of Vessel Motion on the Fatigue of CT
Dr. Steven M. Tipton, The University of Tulsa

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

Session VIII 2:45-3:45 PM

Subsea Decommissioning
Bruce Crager, Endeavor Management

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

Session IX 3:45 - 4:00 PM

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

How MWCC Utilizes Industry's Services and Expertise to Achieve Response Readiness of its Well Containment System
Don Armijo, Marine Well Containment Company

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

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Point by point: **intervention**

In advance of OE's 2014 Deepwater Intervention Forum held in Galveston, Texas, Managing Editor Audrey Leon spoke with representatives of Helix Energy Solutions, FMC Technologies, and consultant Robert Keith of R.J. Keith & Associates, to discuss topics affecting the intervention sector.

OE: I'd like to set the stage with a historical comparison. How have you seen well intervention –both the techniques and technology involved, and the attitudes regarding it – change from when you started your career to now?

Bjarne Neumann, FMC Technologies' Director of Well Intervention Services, Global Subsea Services:

The biggest change in well intervention during my career has been the shift from the use of riser-based intervention systems to the use of riserless intervention systems. These riserless light well intervention (RLWI) systems have had a substantial impact on the economics of performing well interventions on subsea production equipment. There have been challenges convincing operators of the feasibility of vessel–based intervention operations using RLWI, but with a nearly 20 year track record of successful RLWI operations, this technology is no longer considered unproven.

Robert Keith, R.J. Keith & Associates:

When I started, well intervention was always carried out by drilling rigs (MODUs or jackups), and depending on utilization, you had to wait and pay whatever the market rate demanded. It also meant that you paid for the rig during transit to your location, while it was being anchored up (no DP back then), the time it took to do the work, and up until it was ready to leave location. It was very expensive.

These days, there are numerous dedicated vessels, both semisubmersible and an increasing number of monohulls, that can carry out this work, almost all of them DP II or III. There are also several companies that have developed and operate

intervention systems that can be deployed from an appropriate vessel of opportunity. This has certainly reduced the cost and greatly improved the scheduling of well intervention activities.

Along with this increased frequency and greater capability has come a corresponding confidence in carrying out these types of operations, augmented by developing methodologies and regulations.

Colin Johnston, Vice President, Commercial Engineering, Helix Energy Solutions:

I have seen similar developments in both the North Sea and the Gulf of Mexico, in that standard rig-based approaches with completion workover riser systems existed and were used from rigs in a consistent manner.

In order to reduce costs, equipment was adapted and modified on a case-by-case basis, and this was supplemented by ad-hoc, "reach for the sky" projects involving various vessel and service designs and combinations which ebbed and flowed with the oil price and general activity. The more consistent underlying trend has seen dedicated vessels, refined in their design and optimized for efficiency, supplemented with intervention systems—whether riser or riserless—also optimized for their ease of application across all water depths and all tree types. This has been mirrored with the change in attitude from the "rig-does-everything" to selecting the right tool for the right job. More recently, the critical mass of subsea wells in key areas like Gulf of Mexico, North Sea, Brazil and West Africa has also seen a maturity of subsea well operations develop with long-term multi-year contracts specifically for well intervention services being applied.

OE: With large subsea compression developments underway, such as Statoil's Asgard project and Shell's Ormen Lange, operators Statoil and Shell have reported that they don't believe vessels currently exist to properly service and maintain these massive subsea projects. Do you believe this

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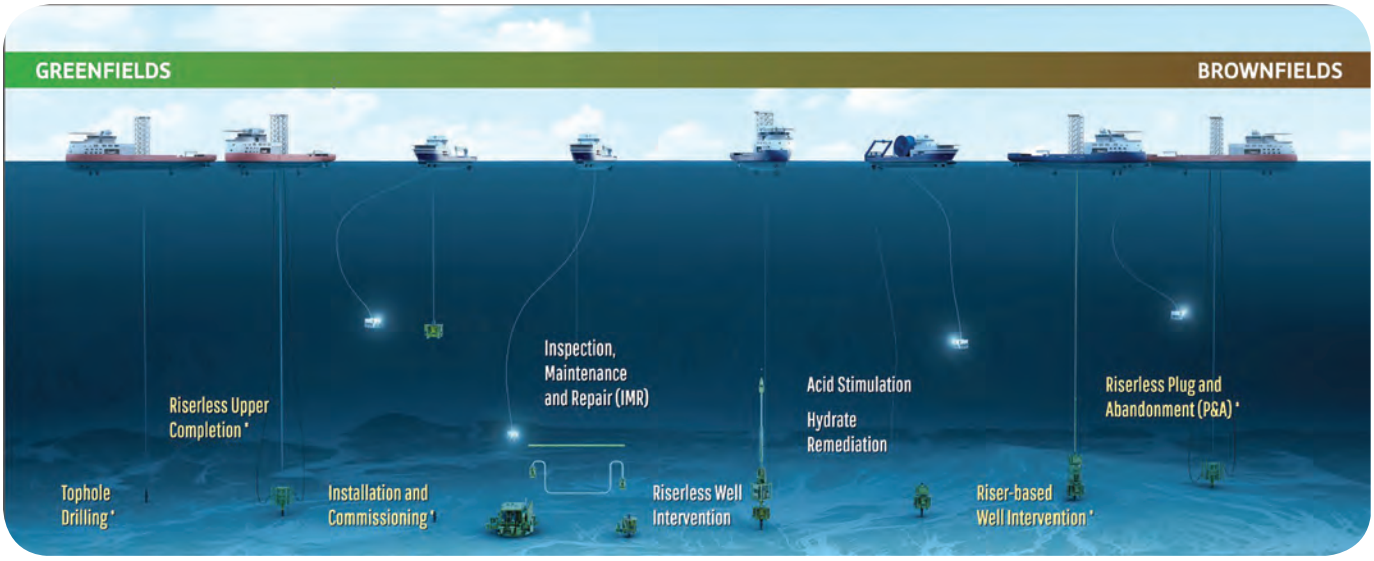

Charting intervention. Illustration from FTO Services.

to be true? If so, what solutions are available now?

Bjarne Neumann: Yes, this is true. Subsea compression systems are different from traditional subsea equipment in size and complexity. With increased complexity, and the fact that this equipment is critical for maintaining production, the operators are forced to have intervention vessels available to pull/set large modules year-round. Another key challenge associated with this type of equipment is the size of some of the components. Today's traditional moon pool size is too small to accommodate some of the equipment and new vessel configurations may be required to handle these new systems.

Colin Johnston: It may be the case, in the eyes of the operator, that the vessel they require does not currently exist. That does not mean that there is an impossible hurdle to get over. The capability of experienced companies to develop the solutions needed by clients has been demonstrated across the board. Helix initially developed vessels on spec. However, as client needs have matured, we have seen increasing involvement from clients to specify directly what they seek. This must be coupled with the necessary commitment to vessel contracting in order that the commercial targets of both client and contractor can be met in terms of vessel provision. Thus, similar to early well intervention needs, subsea processing and compression may remain an emerging market for specialist vessels, if the operators' needs are different from the capabilities of the vessels currently available. I expect it is only a matter of time before those needs are raised by clients, and the contracting community will respond if the commercial rewards are there. I am of the opinion that existing vessel capability and design is fundamentally what is needed, but I believe the subsea interface and intervention capability is where the development should be focused.

OE: Other than vessel availability, what other limitations have you encountered (regulatory or otherwise), if any?

Bjarne Neumann: One of the greatest limitations to the expansion of intervention services is the lack of the appropriate infrastructure needed to support the demand. That, and the need to train the personnel necessary to deliver the services, is going to be a greater challenge than vessel availability.

Robert Keith: A big limitation on carrying out work is the operators and what their various corporate policies are on interventions. They are particularly concerned about contingencies and processes in the event of a DP failure, and ensuring the security of the well and its contents, which is certainly justified, but a common guideline would be advantageous.

Colin Johnston: One area of improvement is for clients and service providers to work together to improve how vessel mobilization and sharing is administered, along with operational planning, across all aspects of field development, maintenance and decommissioning. This would realize overall cost savings through efficient application and, ideally, a certain amount of autonomy applied, or made available within asset groups, to best use the available vessels, systems and services. Viewing overall costs on a production equity basis would see the vessel and services being applied across the board to the betterment of the field development and maintenance requirements.

OE: One topic I have been hearing a lot about at conferences is standardization, in regards to equipment, as one way to bring down high industry costs. Do you believe interface standardization, especially on subsea processing systems, could be helpful for intervention purposes? How would the industry best handle something like this?

Robert Keith: While standardizing interfaces should be an obvious solution for reducing costs, it is apparent that the drive for innovation and development combined with the egoist need to re-invent or just be different, has resulted in several variations, much to the chagrin of the contractors and their ever-expanding tool kit to carry out a single task.

The API standards are excellent guides for designing interfaces and tools, however, they have to be adopted and then followed by the operators and equipment manufacturers. This is further exacerbated by having multiple standards around the world, which, with true international trade, especially amongst the installation contractors and vessel operators, meaning that they must carry a suite of tooling to meet all of the various interfaces.

I believe that a global standard should be agreed upon and adopted so that the correct tooling is always available. This would simplify design, and thereby reduce complexity, reduce cost, and improve efficiency, thereby further reducing cost.

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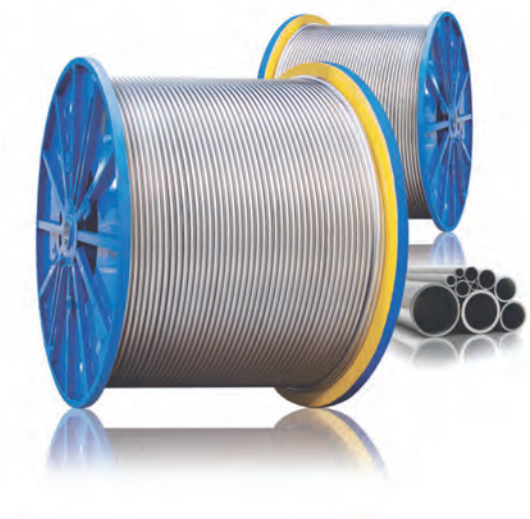

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Colin Johnston: Standardization is the outcome of the focus on regulatory oversight since it is easier to monitor and regulate something that is standard in terms of its application. Consequently, the emphasis within the subsea well operations community is on subsea pressure control equipment standardization with the emphasis on well control and re-entry capability in the event of a major incident. The subsea well operations community has effectively rallied around this cause with significant voluntary support to ensure we have an across-the-board agreement on what subsea pressure control equipment should look like now, and in the near future. The industry is currently handling this very well through the ISO and API process involving, I am pleased to say, both operators and service companies.

Overall interface standardization is helpful for the industry but will be only marginally beneficial in terms of the barriers to entry to the business. The ability to design, build, procure and maintain the necessary systems will rely more on those companies fully committed, experienced and immersed in the subsea well operations business environment to deliver what operators require. Additionally, the operators' level of comfort can only be optimized when those supplying companies can back up the physical equipment offered with the expertise and in-depth knowledge of how best to apply and operate the equipment, whether vessel or subsea, in the most safe and efficient manner.

OE: Last October, OE ran an article from Welltec and Anadarko about Anadarko's "warming up" to riserless light well intervention (RLWI). Do you feel that there are misperceptions about RLWI in the industry? Are you seeing a shift toward its use for maintenance operations, or will heavy intervention vessels still be favored as the most preferred option?

Bjarne Neumann: There is a lack of appreciation for what RLWI systems are capable of these days and a lack of understanding of what can be achieved using these systems. We have seen a tremendous increase in the variety of downhole tools which has, in turn, enabled RLWI to take on more tasks normally associated with riser-based intervention. Typical tasks being undertaken today using RLWI include well logging, re-perforating, side pocket mandrel replacement and scale/hydrate milling.

While Anadarko's venture into RLWI was not entirely successful, there was some benefit gained in the form of "well knowledge." This enabled a better understanding of the task that would need to be performed if it proved financially viable to recover the well. The information gained can be used as a basis of planning appropriate operations and the mobilization of a rig with the correct equipment, rather than an excessive inventory of inappropriate tooling.

Robert Keith: It really depends on what you are trying to do. RLWI is ideal for many "simple" intervention operations like pumping or changing out valves, and does not require the larger, more expensive dedicated intervention vessels that are now available.

Conversely, more intricate operations, further downhole and in more complex wellbores, require a suite of tools and more advanced well control capabilities that are part of dedicated well intervention vessels.

Ultimately, the decision of what methodology to use rests with the relevant regulatory body (BSEE, DOE, et. al.) and the operator, and what their policy is and the level of confidence they have in a contractor and their capabilities.

Colin Johnston: This aspect of either/or with regards to RLWI and riser-based (heavy intervention) continues to crop up. In my opinion, it is about operational risk assessment and applying the right tool for the job. In the key deepwater basins there is optimum opportunity to apply what is needed that enables all relevant players to utilize their assets to the benefit of operators. I believe that within subsea well operations, specific niches will be supplied by those vessels and systems that are perfectly tailored for what they do, whether that is simply data gathering or full through tubing intervention involving stimulation, scale milling, fishing or other production enhancement.

I do not believe there are fundamental misperceptions regarding RLWI, Helix has been conducting such operations since 1990, but I do believe there are conflicting reports regarding method of application and efficiency gains. Both riser-based and riserless are sufficiently mature now that one is not a safeguard for the other, that is to say they are both key services in their own right. Preferred is not the issue – it is being able to apply the right service at the right time and at the right price. I believe only those companies with the full breadth of knowledge of what it takes to provide an integrated service for clients will truly leverage the opportunities offered by both RLWI and riser-based intervention. OE

OE's Deepwater Intervention Forum will be held this August 12-14, 2014, at the Galveston Island Convention Center. For more information, please visit: www.deepwaterintervention.com.

Voices continued. OE asked: **how have you seen well intervention technology evolve?** See p 15 for more.

Francis Neill, Chief Executive Officer, EV

The two main development areas we have seen are subsea well intervention and decommissioning. The population of subsea wells continues to increase and, while many were installed as 'interventionless,' time is proving that not to be the case, as the growing number of riserless light well intervention vessels shows. At the same time, decommissioning of the thousands of suspended offshore wells is happening in greater numbers. Cost-effective solutions are definitely required to meet the varying legislations around the world.

Ian Anderson, Chief Operating Officer, Camcon Oil

There are some areas where technology evolution has actually pre-empted the need for well intervention. This is the case with gas lift where the perennial risks of tangled or broken cables through wirelines are being replaced by the ability for operators to vary injection rates and depths in real-time. The introduction of greater digital intelligence into gas lift and other well intervention-based areas will have a profound effect on operations and well intervention moving forward.

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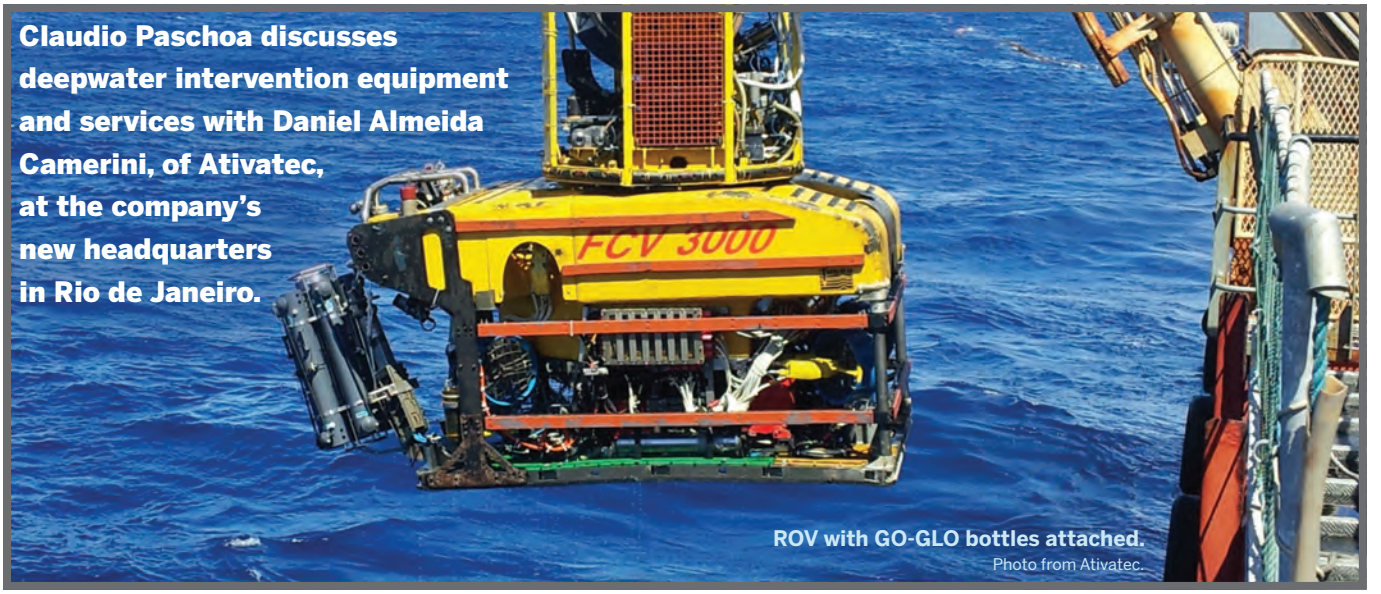
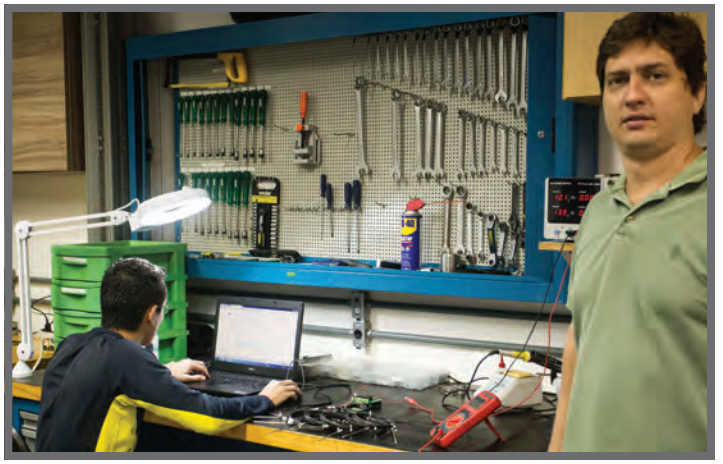
Ativatec makes its mark
in Brazil's deepwater intervention sector



Claudio Paschoa discusses deepwater intervention equipment and services with Daniel Almeida Camerini, of Ativatec, at the company's new headquarters in Rio de Janeiro.

ROV with GO-GLO bottles attached. Photo from Ativatec.

It is widely known that the deepwater intervention equipment market in Brazil is dominated by foreign companies with proven expertise in the area. Very few fully Brazilian companies are present in this market, which is very competitive and requires large investments in high-end technology and specialized engineering skills, making it a market that has products of high aggregated value. With the increasing demand for deepwater intervention equipment and services from supermajors in Brazil, local companies, such as Ativatec, are faced with an excellent opportunity to grow. Daniel Almeida Camerini, a partner in Ativatec, emphasizes that the company continues to look for both local and foreign partners. Deepwater intervention is a constant challenge. Offshore Brazil, where deepwater pre-salt and post-salt plays abound, state oil and gas company Petrobras has invested in local up-and-coming deepwater equipment manufacturers and service providers for many years; yet few local companies can deliver subsea equipment or services that can compete with foreign manufacturers and service providers in terms of quality, reliability and price.



Daniel Camerini at Ativatec's workshop at UFRJ's Technology Center in Rio de Janeiro. Photo by Claudio Paschoa.

Ativatec is one of a small group of Brazilian companies that manufactures subsea equipment and provide services for deepwater inspection and intervention that have managed to win contracts from Petrobras. The company develops and operates equipment in the field for their clients. Ativatec is an offspring of the Genesis Institute of the Catholic University of Rio de Janeiro (PUC-Rio), which promotes technologically-focused businesses ventures run by university graduates.

"The Genesis Institute was important in integrating the company with professors and students at the university, to give visibility to the company through the media and in the technology and business communities specialized in subsea technology in Brazil," Camerini said. Camerini holds a Master's degree in automation and control engineering from PUC-Rio. He has coordinated R&D projects in the oil and gas industry as research engineer at PUC-Rio for the last 10 years and, along with partner Rodrigo Carvalho Ferreira, manages Ativatec. Both are graduates of PUC-Rio, where they also worked on research and development projects in partnership with the Petrobras Research Center (CENPES).

Ativatec first developed the special ROV tool test bolt (FTEB), designed in partnership with Petrobras, for testing integrity and shielding of screws in production equipment such as Xmas trees, MCVs and BAPs installed in water depths of up to 2000m. More than 50 successful inspections were made in offshore production fields for Petrobras in 2010. This tool performs structural tests and corrosion protection in bolts installed in places of difficult access on subsea production equipment. The embedded electronics offer real-time data during the operations.

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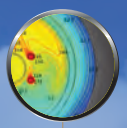
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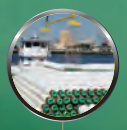
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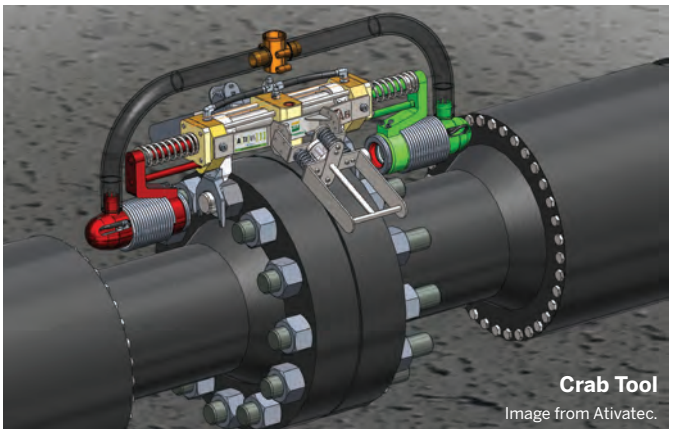


Crab Tool
Image from Ativatec.

In 2010, again in partnership with Petrobras, Ativatec developed another ROV tool for ultrasonic inspection of subsea equipment.

Baptized as Crab Tool, it is capable of detecting 3mm fissures in screws and plates installed in up to 3000m depths with high reliability. In 2011, more than 40 successful field inspections were done and the technology was patented. The Crab Tool is still used by Petrobras in the Campos Basin for inspection of wet Xmas trees and pipeline end manifold, which have bolts as key components.

Due to the extremely aggressive deepwater environment and the presence of hydrogen in water, Petrobras has faced some problems with these bolts, which had failed because of cracks. Offshore ultrasonic inspection is also a great challenge in deepwater pipeline maintenance technology. The Crab Tool or Crack Bolt Detection Tool was developed for in-situ bolt inspection in order to detect cracks, even small ones down to 3mm deep, nucleated from the thread. Fourteen ultrasound transducers, seven per side, sequentially scan the bolt and the respective A-scan is real time displayed at the surface. Once a crack is detected, it is possible to localize its location and length. Designed specifically to be operated by ROVs, the Crab Tool's innovative technology was validated in offshore operations under 900m depth.

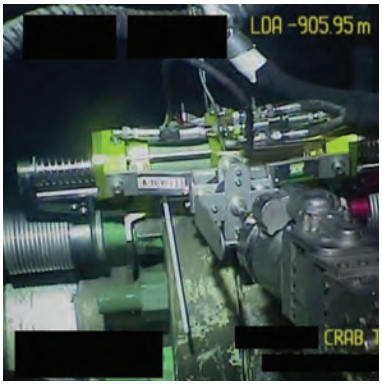
In 2012, Ativatec, once again in partnership with Petrobras, developed another ROV operated tool for use in breaking up hydrates present in connectors, in equipment such as MCVs, SCMs, tree caps and subsea Xmas trees, for the total or partial re-establishment of well production. The technology was approved in laboratory tests and was made available to the market in 2013.

Operators constantly need to deal with unwanted hydrate formation in subsea oil production systems such as pipelines, Xmas trees, manifolds, controls and connections. Hydrate condensation causes different problems, such as decrease in oil flow, blocked subsea valves and environmental risks. The subsea hydrate dissociation ROV tool, called SAES, is capable of heating a specific location of the subsea system and dissociating the hydrates, thus re-establishing the regular flow. The first prototype was produced and tested at Petrobras Research Center's Subsea Technology Laboratory with success at 1500m depth pressure and 100°C temperature. It has been used in the Campos basin at plays such as Roncador and Marlin.

"The challenges in working with products used in the deepwater segment of the O&G industry are in offering products with simple interfaces to be operated and/or installed by ROVs and

that offer at the same time high reliability, minimum maintenance needs, reduced weight and dimensions and high mechanical robustness to resist the high-salinity and high-pressure encountered in deepwater marine environments," Camerini said.

With the increased importance of deepwater environmental safety concerns, Petrobras quickly became interested in another simple and useful subsea ROV tool developed by Ativatec, designed specifically for deepwater environmental monitoring. The sediment collect tool (ASC), performed more than 90 offshore operations at Campos Basin in 2012. Its sample technology does not compress or deform the sediment sample, therefore allowing a reliable environmental sediment analysis. It is capable of sediment collection in water depths of 3000m and has an open/close visual indicator. It is also considerably lightweight at 58kg, with an in-water weight of 44kg and can handle samples with dimensions of 30 cm-by-5 cm-by-5 cm.



Crab Tool deepwater operations.
Photo from Petrobras.

Another Ativatec-designed tool for deepwater environmental monitoring is the Water Sampling Combo 6. It is an ROV tool capable of collecting six water samples in different places in one single dive. The ROV arm secures each GO-FLO bottle in the place and moment that interests the operator for water sampling to occur. Its objective is to monitor, collect and research data on water quality. It has an individual bottle control, a visual bottle closing indicator, and also an ROV hydraulic interface. In 2012, the Combo 6 performed more than 40 offshore operations at Campos Basin.

"The Brazilian market for subsea robotics for inspection, intervention and environmental monitoring is in increasing expansion.

Various companies from around the world are investing in this area due to the aging of existing subsea equipment, which begin to deteriorate due to marine effects, generating production problems and even environmental accidents. Other than that, the exploration of the pre-salt demands great investments in new subsea technologies for E&P in ultra-deep waters, which has been attracting international companies to Brazil," Camerini said.

Deepwater equipment control is always a challenge and it is interesting to look at what equipment Ativatec uses for deepwater acquisition, control and data transmission, and what are the challenges in real-time deepwater data transmission, when asked about this Daniel explained that, "All our equipment has optical interfaces for data transmission, through the ROV video camera and an electric interface via the ROV umbilical. The great difficulty in real-time deepwater data transmission lies in signal attenuation due to the long length of the umbilical cable, which in ultra-deep waters can reach 3km, which many times requires the use of fiber optics."

Looking at the future, Ativatec is striving to increase its equipment while maintaining quality. In less than a year Ativatec has grown from a team of five to 12 and from a 40sq m room to a warehouse at the Federal University of Rio de Janeiro incubator complex located within the university's technology center. OE

Trending upward

Innovation is a necessity when it comes to exploring and producing oil and gas. Audrey Leon discussed recent technological trends occurring in the geophysical sector with several leading companies.

Launched in 2010, CGG's *Oceanic Vega* is a purpose-built high-capacity seismic vessel optimized for reduced noise and fuel consumption. It carries DNV-CLEAN notation for the lowest environmental impact. Photo from CGG.

Improvements in technology, specifically within the seismic industry, are leading oil and gas explorers to obtain better information—and not only about possible finds.

Several trends have emerged throughout the last couple of years, including improvements to marine-towed streamers and ocean bottom seismic, as well as moves toward acquiring broadband, and wide and full azimuth surveys.

However, improved acquisition methods aren't the only way innovation is occurring. On the software side, compression technology, as well as cloud computing, could help revolutionize the industry. All of these improvements are helping to make the big picture a lot clearer for the industry as a whole.

"Over the past several years, we've seen the need to increase azimuth on geophysical surveys, particularly in areas where you have complex geology—subsalt in the Gulf of Mexico, for example," says TGS CEO Robert Hobbs. "The big push since 2004 is to try and figure out ways to most efficiently increase the azimuthal content of data. You're trying to get more directionality in the subsurface with your geophysical signal."

Robert Hobbs

Hobbs continues, "What you've seen in the deepwater Gulf of Mexico is that the subsalt has been covered by wide azimuth. Lately, geophysical companies are returning to these areas and acquiring the next generation of data, which in the subsalt area is full azimuth."

The geophysical industry, Hobbs says, is focusing on acquiring wider bandwidths in order to gain more frequencies in the subsurface. "In the Gulf of Mexico, what you're seeing is a combination of those two trends. You're starting to see companies offer full azimuth technologies, but also broadband," he says.

Hobbs notes that there are different ways to extract more bandwidth out of data and that several companies offer their own technology to do it.

"You can either process more bandwidths out of conventionally acquired seismic streamer data, and that's what we do at TGS; we have our own technology to take conventionally acquired seismic data and extract broader bandwidth out of that data.

"You have a number of companies that are offering technologies that are acquisition-based. The first one to come out was Petroleum Geo-Services'

Modern 3D seismic vessels typically tow spreads of 10 to 16 streamers. Photo from CGG.

(PGS) Geostreamer. Next, CGG came out with BroadSeis. Then WesternGeco came out with ObliQ and IsoMetrix. Each one of those technologies is an acquisition technique to acquire more bandwidth in the subsurface. And TGS has used many of those technologies as well."

Craig Beasley, Chief Geophysicist and Schlumberger Fellow at WesternGeco comments on the difference between IsoMetrix technology and other broadband techniques saying, "IsoMetrix offers broadband data finely sampled in all directions–vertically, inline to shooting, and crossline between the towed streamers. This is designed to improve the resolution of complex geological details as well as offering flexibility for acquisition efficiency."

The Gulf of Mexico, Hobbs says is the best laboratory for testing and deploying geophysical technology for a number of important reasons.

"It's a very prolific basin. A lot of companies are exploring there, and therefore, they are willing to pay for the data," he says. "You also have a very good multi-client environment, which encourages the geophysical companies to invest in new technologies and new data, because they can earn a good rate of return on that investment.

"You also have geologic complexity; you have a broad range—from simple seismic amplitude plays, to deep subsalt plays. That has enabled the geophysical industry to test a lot of technologies in the Gulf of Mexico that they are not implementing elsewhere.

"We've seen those technologies maturing in the Gulf, and I suspect over the next several years you will see these utilized outside of the northern Gulf of Mexico," Hobbs says.

Marine broadband

For CGG, the big trend of the last few years is marine broadband seismic. The company's Technical Marketing Manager Roger Taylor says CGG has seen the market for broadband seismic take off over the last several years.

"Last year, 50% of the work awarded was for marine broadband seismic in the tenders that we saw," he says. "Broadband is very much what is being asked for at the moment."

Taylor says all the major marine seismic companies now offer some form of broadband solution, including CGG, which offers BroadSeis.

"We've acquired over 200,000sq km of BroadSeis data since we introduced it," he says.

"We have a huge amount of ongoing work, for example offshore Brazil where there is 40,000sq km of acquisition in progress with BroadSeis."

Ocean bottom seismic

Many seismic companies agree that there are advantages to deploying ocean bottom seismic. Hobbs believes that it is likely to usher in a renaissance in mature basins such as the Gulf of Mexico and North Sea. "Unlike streamer-acquired data, you have your sensor on the seabed. There is a number of ways to do that. To date, all of those ways have been more expensive than streamer," he says.

"The industry is working on ways to get a lot more efficient in deployment and retrieval to get the cost of ocean bottom seismic down where it approaches the cost of streamer seismic."

Hobbs notes that ocean bottom seismic allows for better quality data, allowing for full azimuth, since the sensor is on the seabed and your source is on a boat that is above that network of sensors.

"That boat can go anywhere you want that boat to go," he says. "You're able to record multiple azimuths."

Colin Hulme, CEO for OceanGeo, an ION Geophysical company, agrees, saying that ocean bottom technology has improved greatly over the years.

"The current technologies for ocean bottom acquisition systems are much more reliable, and are allowing companies to deploy much larger spreads, than previous generations of equipment," Hulme says.

"This is driving a sub-trend that is making ocean bottom seismic more and more economic. At the same time, ocean bottom seismic provides a naturally full azimuth capability, quieter data and the promise of multi-component data to unlock more information about the reservoir geology."

Hulme says in terms of E&P companies' marine seismic budgets, he is seeing an increase in the percentage allocated

CGG's research and survey vessel *Oceanic Vega* is an SX120 hull form designed by Ulstein. Photo from CGG.

for ocean bottom seismic projects.

"It's been growing consistently since 2006, from 6% of all marine seismic dollars spent to 13% last year," he notes.

This doubling of ocean bottom seismic market share is driven by the need for high quality seismic for managing production and development projects, improved economics of ocean bottom seismic acquisition systems, and the need to acquire high quality seismic in highly congested fields."

While marine towed seismic continues to dominate the exploration and multi-client segment, Hulme believes, in time, the technology trends and associated economics will see ocean bottom seismic take a slice of these segments away from towed streamers.

"We will have to see how big that slice becomes," Hulme says.

Watch this space

CGG's Taylor says there are two areas still to watch in marine seismic: streamer and source technology.

"On the streamer technology side, we saw the introduction of dual-component streamers containing hydrophones and vertical geophones by PGS," Taylor says, noting that WesternGeco and CGG's Sercel have now introduced multi-component streamer technologies containing hydrophone, vertical and crossline geophone components.

"The streamers are recording the same kind of wave field you would record with a regular streamer, but you're gaining directional information as well," he says.

"It's early days for these techniques, they're not necessarily going to do things like improve bandwidth or improve low-frequency recording. This extra crossline information could have some interesting applications for data interpolation, so in principle you can tow streamers further apart, and complete surveys more efficiently, and also enable some new processing techniques which could improve subsurface imaging."

Of course, the technology could be limited, he says, stating that he doesn't believe these type of multi-component streamers will enhance subsalt imaging, for example, on their own.

Beasley offered more detail on WesternGeco's IsoMetrix technology is used in the field. "Not only does the IsoMetrix system employ traditional hydrophone and vertical pressure measurements, it incorporates a densely sampled crossline gradient measurement – a totally new measurement for marine acquisition.

"The crossline gradient allows the streamers to be placed farther apart than conventional systems and, at the same time, allows a 3D reconstruction of the seismic wavefield," Beasley says. "As a result, we get the best of both worlds—efficiency due to wider streamer spacing and a fully 3D broadband solution that goes beyond the 2.5D measurements achieved by other systems.

"The broadband problem is a 3D problem, an issue that has been ignored in the past. With the new measurements now available, a 3D solution is now available commercially."

On the source side, Taylor says marine vibrators have been widely discussed. "This is getting away from our traditional air gun sources, which can be contentious because of the noise they create and the potential impact on marine mammals," he says. "Marine vibrators have potential practical and geophysical benefits, including access to environmentally sensitive areas where air guns may not be appropriate, their suitability for all water depths, improved bandwidth and signal encoding."

Currently, Shell, ExxonMobil and Total are participating in a joint industry research group to develop marine vibrators.

"It's something we are interested in as well," Taylor says. "They could provide access to areas that are restricted by marine environmental regulations. Marine vibrators are not as "loud" as air guns; they generate a continuous

signal that has a lower peak intensity. "According to a recent study made for the joint industry research group, this would allow a smaller marine mammal exclusion zone," Taylor says.

Non-seismic technologies

Hobbs says there are a number of non-seismic technologies that TGS is monitoring, and one of those is electromagnetic (EM) technology.

"We've been active investors in the Barents Sea off Norway, along with EMGS—the EM specialist in the industry," Hobbs says. "I think it is a valid tool, in certain types of geology. We're focused on identifying the areas where it works and where it is synergistic with our seismic activities.

"You can interpret seismic without EM, but it is almost impossible interpret EM without seismic."

Hobbs says TGS will continue to invest in EM where the company has a very strong seismic database that can be used in conjunction with interpreting and processing EM data.

A compressed future

Craig Beasley

Beasley is excited about what the future holds for the geophysical industry. Beasley said compressive technology caused a big stir in the medical imaging field and could be revolutionary for seismic acquisitions.

He says where it might be advantageous to put out more sensors for acquisitions, more may not be required. Beasley says with compressive technology you have to be smarter about the complexity of the thing you are trying to measure. He relates the technology to how compression revolutionized the music industry by taking music compressed on compact discs (CDs) and compressing further into MP3 files, which allow for more storage without noticeable loss in quality.

"A more fundamental question would be, did I need to make all those elaborate measurements to start with, if I could simply compress with a factor of ten," Beasley asked. "Couldn't I have only sampled 1/10 of the data to start with? That way you would save a lot in the recording phase. It may not make that much sense for the digital media, but for the seismic industry, this could be groundbreaking."

Beasley says WesternGeco has implemented a type of compressive sensing on the source side, called SimSource, a simultaneous source acquisition and processing technique. This technology, Beasley says, allows for two or more seismic sources to be active in the field at one time, both able to recover data.

"This breaks all the rules for geophysicists," he says. "The commercial introduction has been some time coming, because it is totally contrary to all the principals of geophysical data acquisition. We don't like to have more than one source active because one air gun source looks like another, so when you record two that are active at the same time on the same record, how can you tell which

information came from which source? Different techniques allow us to do this separation."

Beasley says having two sources active allows for recording more data in the same time frame. "In the geophysical industry, time is money," he says. "By compressing the data at the acquisition phase, this allows us to gain factors of efficiency that you wouldn't with just a single source active.

"We believe that compressive sensing will revolutionize the data acquisition world in general, not just seismic," Beasley says. "The need for compressive acquisition will be extremely important."

Deploying an air gun umbilical. Photo from OceanGeo.

Handling big data

Big data affects all aspect of the oil and gas industry and the software development business is no exception.

Duane Dopkin

"Data size and data diversity is a huge challenge in our industry," says Duane Dopkin, executive vice president of geoscience at subsurface software developer Paradigm. "The volume of metadata that has to be managed and referenced, the diversity of data that has to be consumed in our software platforms, and the volumes of data that needs to be visualized, interpreted, and modeled, puts a lot of pressure on software developers to accommodate that."

Dopkin notes the need for compression and the need for software to comply with this technology.

"In the 1990s, data compression became very topical and popular because we were trying to do fast-track seismic processing and (send via) satellite that information back to the office, so it could be worked on in more detail," Dopkin notes. "The disc costs and technology were not able to keep up.

"That changed in the 2000s with affordable storage and improved technology, but now the industry has a full appreciation for high density and high resolution seismic data," Dopkin says. "Improved computer assisted technologies are needed to interpret, model, and validate these vast volumes of seismic data. New ways to manage, reference, and query all of the petrotechnical metadata associated with active conventional and unconventional fields has to be addressed by our software. That's just one general topic, but it has a huge impact."

Halliburton's Landmark is dealing with the same big data issues, and is attempting to tackle the need for a common platform.

"The oil and gas industry is a huge


Michael Dunn

user of data," says Michael Dunn, senior director of geophysics, geology and reservoir engineering for Landmark. "How well you move data across applications is important. You want to have a common platform for E&P data, an enterprise platform, and we're working very hard on it."

Dunn says cloud computing, which offers essential infinite compute and data storage, could offer a solution.

"The benefits are pretty obvious," he says. "For oil and gas companies, in addition to increased capacity the Cloud also provides the ability to provide software version control much better than these companies can today.

"If you go to any large company and look at what they're running, they are usually behind with regards to the latest release.

"For example, it is not unusual for a large company to be two versions behind on Microsoft Office. The reason is often that they have a lot of programs that are dependent on a particular version and they can't bring in the new version until all of those dependencies are tested."

Dunn says version control is easier to manage on the Cloud because the local computing environment dependencies are removed and the software is simply accessed through a browser.

With infinite compute and data storage, he says, if there is a large project that a user wants to run, and it requires a large computer infrastructure, the Cloud is available 24/7. Today the cost for on demand compute is high but it rapidly decreasing as the capacity continues to grow, Dunn says.

"If I had a steady state usage, and I need peak demand, the Cloud could give me that as long as I have the dollars to pay for it," Dunn says. "Rather than build my own infrastructures to handle those peaks, I could do that through the Cloud."

Incorporating automation

Automation is a big topic, especially as companies seek to bring more workers onshore, and reduce human error.

Landmark's Dunn takes a more conservative stance of automating the geophysical industry, especially where interpretation is concerned.

"While automation will play a role for individual tasks, a lot of interpretation steps aren't easily automated," he says. "For that reason and the significant variation in seismic data quality, a completely automated interpretation system will most likely not happen in the next 10 years."

"I don't see a fully automated interpretation system," he continues. "Other areas can be automated: deep sea systems, robots that go out and place sensors on the seafloor in deepwater. However, it's hard to automate those areas where human judgment is required."

The bright side

Hobbs says the exciting aspect of the geophysical industry is being able to watch technology change and adapt.

"The geophysical industry is the one industry in the oil and gas field that has advanced the fastest," Hobbs says. "I'm biased because I'm a part of it, but it delivers more value than any other technology in the exploration and production field, in terms of being able to predict what your drill bit will encounter." OE

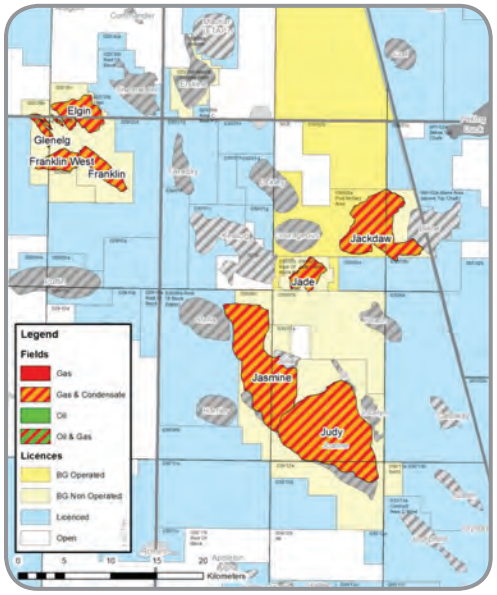
The HPHT challenge

High-pressure, high-temperature developments are on the increase in the UK North Sea. Elaine Maslin went to an Oil & Gas UK breakfast briefing in Aberdeen to find out more.

North Sea operators are breaking new ground and investing in new technology development to bring high-pressure, high-temperature (HPHT) and ultra-HPHT fields onstream.

It is an extreme, expensive, and challenging game, but one in which many see the potential for some sizeable new developments in the North Sea.

The numbers are high. BG Group's Jackdaw discovery, in central North Sea Blocks 30/2a (BG Group 44.1%), 30/2d (35%) and 30/3a (30.5%), contains 125-250MMboe and a wider development taking in other fields in the area could unlock 0.5billion boe, BG Group's managing director, Europe E&P, Andy Samuel, told Oil & Gas UK's HPHT breakfast briefing in Aberdeen early June. This would amount to 10% of the UK's domestic gas consumption needs.



BG's Jackdaw discovery. Image from BG Group.

But, Jackdaw is also an extreme field, with 17,250psi reservoir pressure and temperatures at 385°F at its base, making it the highest pressure field found to date on the UK Continental Shelf.

It is new territory. BG Group had to qualify new equipment to carry out a 2012 drill stem test on Jackdaw. Giving an example of the technology that will be required to develop the field, Samuel said BG has been assessing a high integrity pressure protection system (HIPPS), involving numerous fast-closing ball valves, weighing well over 10-tonne each, on the development's well head platform.

Jackdaw was discovered in 2005. BG has since run a four-well, £450 million appraisal program, from 2007-2012.

The discovery extends across three licenses, with lean gas-condensate in high permeability Jurassic reservoir, similar to Total E&P UK's Elgin Franklin development.

Samuel says BG has been through concept select on Jackdaw, with a three-platform base case concept, "remarkably similar" to a development concept chosen by Maersk Oil North Sea for its Culzean HPHT development, also in the central North Sea.

But, costs are crucial on Jackdaw and it is taking longer than BG Group had envisaged to make its economics stack up. The firm is assessing the potential for Jackdaw to be part of a larger cluster development, taking in other nearby fields and prospects, operated by BG as well as other operators, primarily GDF Suez E&P, but also Maersk, to make it and other projects it work.

Despite the challenges, operators, including BG Group, say there is a "substantial yet to find prize" in HPHT.

Total E&P UK's HPHT Elgin Franklin complex.
Image from Total E&P UK.

How it is done

Total E&P UK has led the HPHT-way with its Elgin Franklin HPHT development in the central North Sea. It was challenged with pressures up to 15,500psi and temperatures up to 350°F.

It has had a learning curve, due to the 2012 well control incident on Elgin, but it is also extending the development. In the fourth quarter, it is due to bring on stream two new platforms at the Elgin Franklin complex—West Franklin and Elgin B—part of the development's life extension, from 22 years, as initially anticipated, to 32 years.

Philippe Guys, managing director, Total E&P UK, told the Oil & Gas UK briefing that HPHT is a large proportion of Total E&P UK's operated reserves, totaling 54%. Some 48% of the UK's yet

Maersk's proposed Culzean development. Image from Maersk Oil UK.

to find reserves are in the central North Sea, of which 25% is thought to be HPHT, he says.

"It (HPHT) is a big deal to us, these are highly technically challenging fields we need to develop," Guys says. But it is also a niche, he adds. "We had to develop new tools for this."

Franklin was discovered in 1986 and Elgin in 1991. It took 15 years and £20 million of research investment, before both could be produced.

Initial development challenges included 3-4% carbon dioxide, 30-50ppm hydrogen sulfide, and a 1100psi, 190°C temperature reservoir. There was also 175 g/l formation chlorides. Gas also had to be delivered to the grid to specification, which added to the challenges.

To meet some of these challenges, a large well bore completion (5in, tubing) was used to avoid local focal stress on production tubing. A 15,000psi coiled tubing system was developed for through tubing perforations, a production packer was designed and qualified for Elgin Franklin, and the company had to develop and qualify a 12in, 12,500psi emergency shutdown valve, Guys says.

To reduce costs, Total used a TGP500-design platform, to limit offshore commissioning and hookup as well as offering a simpler decommissioning solution. A drawback is a weight limit, Guys says. The firm also used titanium heat exchangers, which are no longer in production, which could pose a future problem. Other innovations included a large diameter (42in.), high temperature (165°C) pipe in pipe bundle, which included foam insulation, qualified to 160°C, and a special caisson cooling system design for the Franklin wellhead platform.

When Total was developing Elgin Franklin, Shell was developing its nearby Shearwater field, another HPHT development. Guys says the firms collaborated on a number of areas on these projects and now even share a backup power supply.

A more recent challenge on Elgin Franklin was developing extended reach wells to produce the Glenelg field, discovered in 1999, and developed in 2006, with a 7.7km-long well, at a 4km step out.

In 2008, Total drilled its first infield well on Franklin, which has helped to extend the development's field life. Initially, the firm had not thought infill well drilling would be possible, due to pressure depletion on the field. But, a well drilled in 2008 produced, "opening a new horizon," Guys says. Technology used included stress casing mud and using graphite and calcium carbonate to plug the fractures in the reservoir as they drilled.

The 2012 Elgin incident gave the firm a major challenge, and learnings. Pressure depletion in the reservoir caused compaction, which resulted in a rearrangement of the chalk fractures, and introduced some permeability. This meant sustained pressure came from a chalk reservoir that Total had not found or expected gas to come from. In addition, a 10¾in. production casing failed below its design parameter "due to unique stress corrosion cracking phenomena due to the joint dope and the CaBr2 brine," Guys says.

Since understanding how the incident happened, Total has developed a new safety case on Elgin Franklin and a new annulus management system has been developed. To learn more about the behavior of the chalk, Total is planning a pilot using seismic nodes on the seedbed.

Culzean

Another major HPHT development is Maersk Oil North Sea's £3-4 billion Culzean development in central North Sea Block 22/25a. Discovered in 2008, Culzean could be producing about 5% of the UK's domestic gas needs by 2020. First gas is due from a new three platform installation, including a 12-slot wellhead platform, in 88m water depth, in 2019. The reservoir is about 4300m below sea level and about 170°C, some 242km from Aberdeen in the central North Sea.

Martin Rune Pedersen, managing director for Maersk Oil UK, says getting wellhead and downhole engineering right will be critical on the project, as well as material specification.

HPHT challenges have been recognized by the UK government, which is out to consultation with the industry on a new tax allowance. OE

Sampling the pre-salt

Halliburton's Antônio Mataruco, Flávio Dias, and Fernando Marcançola discuss the first fully acoustic-telemetry downhole sampling operation in a pre-salt environment in deepwater Brazil.

The new oilfield reserves recently discovered in Brazil have been located in more hostile environments than previously explored; these investigations had not been pursued earlier, because until recently, no technology was available that would allow safe investigation and production in the deeper, more hostile environments. In addition, it was not feasible to attempt to research these areas, when considering that drill-stem testing (DST) operations require reduced pressure applied to the annulus to operate the downhole tools. In addition to safety, economics also was an important consideration because of the various wireline operations that would be necessary.

Fluid sampling operations are very important for reservoir evaluation. But, to consider testing in the deep, more hostile environments, the methods traditionally used for conducting sampling had to be adapted to the new scenarios, before they could be considered for accurate testing operations. The goal of this discussion is to review a case study in deepwater Brazil to explain how a testing application using acoustic telemetry technology was capable of operating in the hostile conditions to perform the diagnostics required from downhole fluid samplers.

Representative reservoir fluid samples are essential prerequisites for providing quality fluid properties and characteristics. Accurate sampling techniques often provide critical input to reservoir simulation models and help to optimize processing of facility designs to help boost the profitability of an oil or gas field. A physical sample of the reservoir fluid is also crucial for defining the potential monetary value of a hydrocarbon reserve.

Figure 1: Internal and external rupture disks. Photos from Halliburton.

Acoustic telemetry systems help optimize operational cost because of their capability to quickly access real-time data pertinent to the reservoir evaluation, thus allowing immediate well-timed decisions or changes to be made to DST operations.

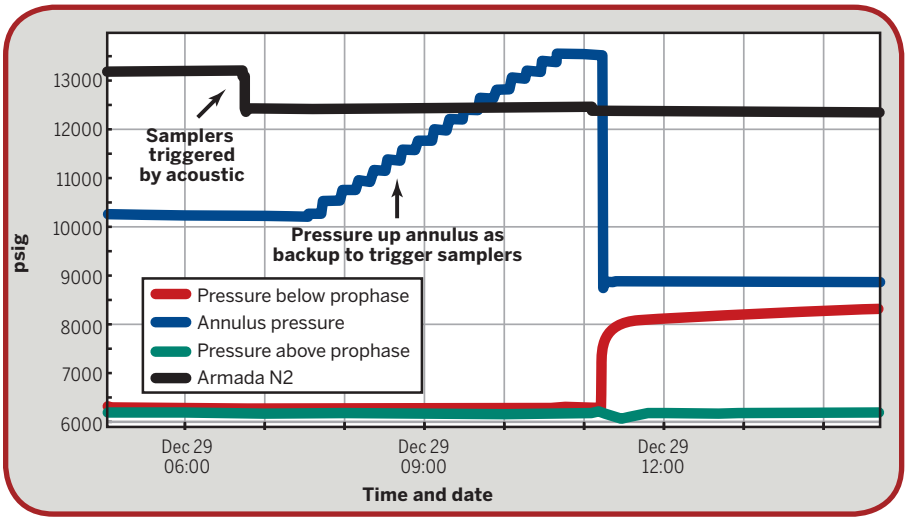
For the first time, the major operator in Brazil made the decision to use real-time acoustic telemetry to monitor and control a DST operation. The job was conducted from a semisubmersible rig, at 7053ft water depth, in the pre-salt region of southeast Brazil, in a well 17,600ft deep.

The bottomhole sampler is one of the most important tools in a drill-stem testing operation. It is responsible for collecting the first representative sample of the fluid produced by the reservoir. Its operation was usually performed by the actuation of rupture disks. Up to three different disks could be installed, allowing the actuation of the sampler in three different times of the testing. Each rupture disk was connected to three different samplers, totaling a quantity of 3600-cc of representative samples.

On the other hand, adapting the pressure ranges of each rupture disk demanded predetermined calculations. Besides the samplers, all the rupture disks used for the downhole tools were required to be within a tight range that had to be determined by the pressure to which the casing has been previously tested.

Using acoustic telemetry-operated triggers, the samplers can be actuated by rupturing internal disks, which are not dependent upon the annulus pressure.

Acoustic telemetry communication with the bottomhole samplers provided important advantages to the client:



Annulus pressure ensuring sample was collected acoustically.
Source: Halliburton.

- Push-button actuation
- Real-time status diagnostics
- Real-time confirmation of the actuation
- Actuation of groups of three samplers at different times, regardless of the casing maximum allowed pressure
- Easy-to-adapt pressure ranges of the rupture disks for other tools
- Redundant method of actuation.

In this DST, the acoustic triggers were actuated on the 15th day of operation. The acoustic command was sent and received downhole successfully. It was confirmed because of the feed-through capability of the acoustic system. The "fired" diagnostics status was sent, after the sample had been collected.

On the 37th day of operation, the bottomhole sampler was pulled out of the well. The downhole sampler's rupture disk was intact. Then, it was possible to visually confirm that the bottomhole samplers had been acoustically actuated (See figure 1).

A pressure and temperature gauge installed on the nitrogen chamber of the bottomhole tool also confirmed the actuation of the nine samplers at the same time. The gauge allowed the reservoir engineer to confirm that the sample bottles had maintained the reservoir pressure. This ensured that the collected fluid had contained all the physical and chemical characteristics required. The verification that annulus pressure provided showing that the sample was collected acoustically is shown in the graph.

The black line shows the pressure data collected by the gauge installed on the nitrogen chamber of the bottomhole sampler. The blue line represents the annulus pressure. In fact, the nitrogen pressure did not change when the annulus pressure was applied. This is another reliable indication that ARMADA bottomhole samplers were actuated acoustically.

As presented, the results proved the success and quality of the sampling operation, in a reliable and distinctive manner. The operational safety is a great advantage, as the use of annulus pressure can be largely minimized.

A benefit of the wireless operation, the acoustic method of actuation of the ARMADA bottomhole samplers has the potential to save days of rig time. Once the reservoir and well engineers define the proper moment to actuate the samplers, a single click on the control computer will start the process. Additionallty, the risk of repeating sampling operations due to the collection of unrepresentative samples is very unlikely to happen. Constant monitoring of the pressure and temperature of the sample guarantees that it has been monophasic during the entire test.

Recently released by Halliburton, the RezConnect well testing system provides an acoustic feedback feature. It allows for complete understanding of what is occurring downhole. This capability enables immediate and accurate decisions to be made during well test operations. Decisions are made in real time. Operators can more efficiently plan and achieve their intended well test objectives, with less rig time compared to conventional sampling and testing methods.

Using Halliburton's successfully established proprietary DynaLink telemetry system, RezConnect well testing system integrates all the DST tools and allows surface verification of operational status.

Now operators can monitor, analyze and control their wells and downhole tools acoustically. OE

Flavio Dias *joined Halliburton in 2001 as a data acquisition specialist for testing and subsea (TSS). In 2004, he worked overseas, developing skills on surface well testing technologies. After his return to Halliburton in 2007, Flávio worked as a TSS field engineer, testing offshore coordinator and DAS shop supervisor. From October 2012 to March 2014, he was the testing and subsea technology technical professional engineer for Latin America, based in Carrollton, Texas. Flávio currently works on the TSS business development team in Southeastern Brazil. Flávio holds a degree in petroleum engineering from Universidade Estácio de Sá.*

Fernando Marcancola *has over six years of oilfield experience in deepwater exploration as a reservoir field engineer in Brazil. In 2013 Fernando held an assignment at Halliburton's Technology Center in Carrollton, Texas, supporting operations and technology for well testing operations, focused mainly on telemetry controlled well tester valves. Currently he is a project team coordinator for Halliburton's Testing and Subsea product service line in Brazil. Fernando holds a degree in control and automation engineering from Universidade Federal de Itajubá in Brazil and is currently pursuing a Master's degree in petroleum engineering at Heriot Watt University.*

Antonio Mataruco *joined Halliburton in 2009 as a testing and subsea field engineer in the sampling sub-product service line and worked with Sampling in Brazil and Mexico. He was promoted at the end of 2013 to the shop supervisor position. Antonio holds a degree in production engineering from Universidade Federal de Itajubá.*

Metal-to-metal completion technology

Well integrity has been defined by a reactive approach and the limitations of current well planning and intervention technologies. Mark Rivenbark looks at an alternative approach.

One of the biggest issues facing the offshore oil and gas sector today is well integrity. This challenge was made apparent by a study conducted on a number of wells on the Norwegian Continental Shelf by Norway's Petroleum Safety Authority (PSA), which found that every fifth well analyzed had well integrity weaknesses.

Regulatory requirements, in the North Sea and Gulf of Mexico in particular, are increasing the onus on operators to establish structural integrity and contingencies at the planning stage; recomplete existing producing wells to comply with new legislation; ensure that well integrity is not compromised by trouble zones and stuck casing; and reinstate well integrity quickly when damage does occur.

Despite the growing importance of well

Metalmorphology is the process of shaping metal downhole to provide a metal-to-metal, gas-tight seal for the life of the well. Photos from Meta.

Liner tieback – The durability of the metal-to-metal seal enables the liner tieback to operate at high pressures and temperatures, making it ideal for deepwater challenges.

integrity – particularly since Macondo – questions still remain as to well integrity's role in the well's lifecycle. Questions include: What exactly is well integrity and when does it start in the well lifecycle? Is it possible to protect it and at what stage? And how can a safe and effective balance be found between protecting well integrity while maximizing production?

Robust well integrity

Sadly, many older wells were not designed for long life, so in some ways they were destined for early failure from the outset. Well life cycles of 30-50 years are what is needed in many producing fields around the world. These life cycles are achievable. Many studies based on statistical data have been conducted over the years in an effort to understand the causes of casing failure and possible solutions. This has involved the study of large data sets gathered over many years of production.

For external corrosion of wellbore casing and strings, caused by corrosive aquifers, for example, protective coatings, thicker casing and cementing all strings to surface are just some of the tactics that have been used to combat the attacks on the integrity of well bores. The loss of production inflicted on operators by the corrosion of casing strings is indeed substantial and in fact is growing every year. This can even lead to the loss of the well and/or damage to the reservoir. Some operators have reported well failures in as little as two years from the start of production of a well.

Many operators have carried out a detailed risk analysis of their well stock in an effort to rank each well from good to bad. This type of risk analysis is only as good as the data available for review and evaluation. Designing a robust, database-driven, analytical tool is a first step in risk ranking of a given well stock. Factors to be part of the database includes well construction types, annulus pressure, production data and well intervention information just to name a few of the parameters to investigate.

A system designed to monitor and manage well integrity should at a minimum set out clear standards to ascertain the integrity of the wells under management for their entire life cycle. This would include safe and continuous functionality aimed at meeting required production targets. In light of past well integrity lapses, some of which have resulted in loss of life and environmental and economic damage, a robust well integrity management system is a requirement for any operator interested in being a good corporate citizen.

The limitations of existing isolation technology

While technologies, such as inflatables, swellables and mechanical packers, have played a key role in securing well integrity and zonal isolation in the past, they do come with limitations. Swellables in particular are relatively inexpensive and easy to install without compromising casing strength, and yet come with reliability issues relating to the polymer swelling, the size of the diameter changes, structural integrity issues from other fluids, and the time it takes to swell, which can sometimes be up to 30 days. These technologies have an important role to play in isolation, but there is a need for other technologies to harness their benefits while overcoming their weaknesses.

Metal-to-metal

Meta has Metalmorphology for this area. Metalmorphology uses established metal working principles to shape metal downhole to deliver a gas tight and durable metal-to-metal seal.

The technology balances the mechanical strength of steel with its elastic properties to create isolation solutions that instantly morph together to provide 100% conformance within the wellbore or casing. It provides a morphing ratio up to 60%, an axial load bearing rating up to six million lbs, and a sealing rating of up to 15,000psi.

The result is a gas-tight, axial load bearing, metal-to-metal sealing solution, which meets well integrity legislation as well as giving operators absolute confidence in their isolation and well integrity solutions.

The Meta liner tieback connects the liner to a tieback receptacle built into the previously run casing string.

Delivering tieback integrity in the North Sea

A Meta liner tieback, which uses Metalmorphology metal-to-metal morphing technology, was recently installed by a North Sea operator.

By morphing metal, the Meta liner tieback connects the liner to a tieback receptacle built into the previously run casing string. The result is a fully compliant V0 ISO14310 certified metal-to-metal connection with no reduction in internal diameter (ID) and no reliance on elastomers, capable of offering full integrity for the lifetime of the well.

The durability of the metal-to-metal seal enables the liner tieback to operate at pressures of up to 13,500psi at temperatures of 320°F and with an axial load bearing capability of up to six million lbs, making it ideal for deepwater challenges. It can be installed faster than other methods.

On the North Sea application, the field came with drilling and well architecture challenges that were preventing completions. One particular challenge was equivalent circulating density (ECD), which can lead to wellbore instability. The operator needed a strong liner tieback interface with no reduction in ID and the ability to avoid tying liners back to the surface for as long as possible.

The liner tieback was installed on a 9-5/8in. liner, allowing the operator to drill multiple sections below, while keeping the 13-5/8in. casing above the liner open for as long as possible.

Meta successfully ran the liner tieback to 3000m depth. It was deployed through a 65° build section and successfully set in 15ppg oil-based muds and at 70°C. The result was a life of well, gas-tight connection that extends the envelope for well construction and delivers tieback integrity over the lifetime of the well. The operator benefitted from improved control over the well, reduced rig costs and non-productive time, faster drilling and earlier revenue, and profitable and productive wells for the life of the field.

Strengthening well architecture in the Gulf of Mexico

A series of Meta tieback systems are due to be installed in a deepwater Gulf of Mexico field. The operating temperature will be 120°C and, once the tieback is installed, the deployment depth 10,000ft. Hydrostatic pressure at this depth will be 3750-5800psi, depending on fluid in the well.

Through the incorporation of the liner tieback into its' well architecture, the operator will ensure that the company remains fully compliant with current regulations; overcomes limited IDs in casing strings to achieve high load bearing capabilities; allows asset teams to plan for drilling deeper; and provides flexibility of space out.

Conclusion

For too long, well integrity has been defined by a reactive approach and the limitations of current well planning and intervention technologies. Metalmorphology is providing a new way of working. OE

Mark Rivenbark *is VP Global Sales at Meta. He has over 25 years' experience in the oil and gas industry, having begun his career on Alaska's North Slope as a completions engineer. Rivenbark previously worked for Dresser Industries, Halliburton, and Enventure Global Technology in various sales, technical, and management positions. He majored in applied science at the University of Alaska-Anchorage with an emphasis on metallurgy. He earned an MBA from the University of Liverpool.*

Versabar

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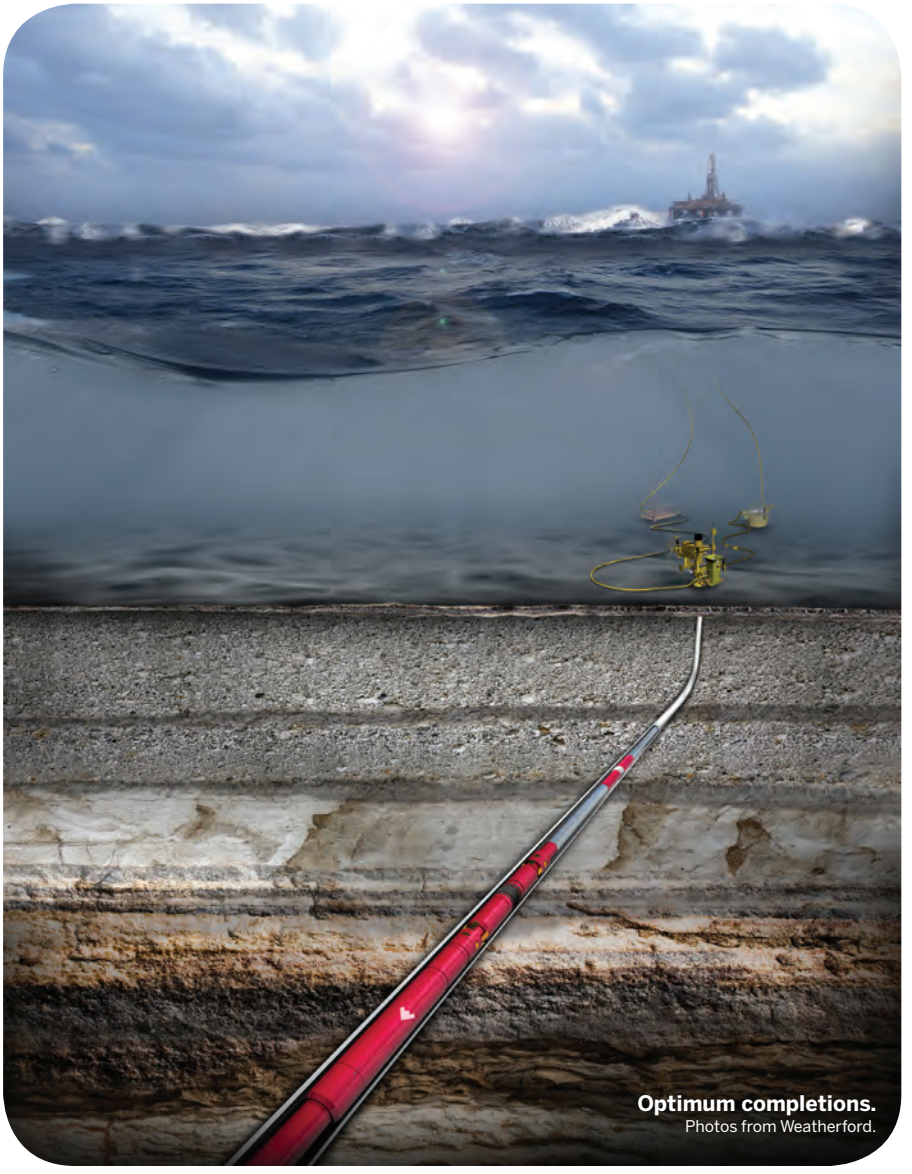
Planning for success

Weatherford's Yvonne McAnally and Ben Lake show how collaboration and integrated methodology delivered an operator's first subsea well project in Norway.

The risky business of oil and gas development is no more evident than in the subsea sector, where the complexities of positioning the wellhead and infrastructure on the sea floor have taken technology development to a new level of sophistication.

In venturing into this important frontier, however, the industry has learned that successful completions require more than the application of advanced tools and technologies. Operators are looking for methods that bring integration and collaboration to the subsea arena, from extensive planning and testing, to the installation of correct equipment to ensure wells are designed and produce as expected.



Optimum completions.
Photos from Weatherford.

In 2013, a North Sea operator used an integrated, collaborative approach to complete its first subsea well project in Norway. This was a two-year undertaking that resulted in two satellite oil wells being successfully brought online. For service company Weatherford, the project was the first fully integrated subsea completion involving both the upper and lower sections of a subsea well.

The wells, at total vertical depth of 3600m (11,811ft), are located in the North Sea's Jette field, estimated to hold 14MMbo. The region is highly regulated by Norway's Petroleum Safety Authority (PSA), which oversees technical and operational safety in hydrocarbon production, ensuring that companies implement the appropriate safety barriers to ensure long-term well integrity. Weatherford was selected to design, build and install the subsea completion into 9 5/8-in. main-bore casing strings for the two subsea wells in 127m (417ft) of water. The wells were eventually tied back to the ExxonMobil-operated Jotun B production platform.

The completion system needed to include a safety valve, packers, liner hangers, swellable packers and screens, as well as the capability for the required cable and gas-lift systems and well control. The cornerstone of the operation was Weatherford's Optimum cased-hole upper-completion system, which combines various modular tools that, when used together, create a customized solution based on the needs of a specific well.

Weatherford worked closely with the operator in conducting extensive analysis of the reservoir data to ensure selection of the proper equipment. Extensive studies of the expected production profiles and planned operating life of the wells were performed, along with casing configurations, connections and subsurface tree design, which has an impact on how the completion is carried out. For example, trees must be designed to enable operations, such as chemical injection, that may be required later in the production life of the well.

Well on paper

The planning phase included a comprehensive well design on paper, where both companies examined the running procedures for every aspect of the completion, including all the equipment that would be needed for the lifespan of the well.

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The process was repeated several times prior to equipment installation. Ongoing project management also included a quality control plan that documented the quality-assurance requirements for the safe manufacture, inspection and testing of all cased-hole completion components for the wells. Most of the equipment was built in Houston or Aberdeen to meet the delivery deadline.

Since many wells in the region at some point require artificial gas lift to enhance recovery, the design incorporated gas lift mandrels and other equipment to eliminate the need for future costly workover operations. Risk and contingency planning also were built into the completion design.

The lower completions included more than 100 standalone screens with inflow control devices (ICD) that were installed to regulate flow into the screens and establish consistent production. The ICDs also prevent formation sand from creating localized erosion, a phenomenon known as hot spots. Swellable packers were installed in the open hole zone to isolate the formation's different production zones and prevent cross-flow between the zones in the event of a pressure differential. Liner packer hangers were installed to take the weight of the tubing string and serve as barriers between the reservoir and the casing.

For the upper completion, all elements of the Optimum completion platform were implemented. The OptiMax tubing-retrievable, surface-controlled subsurface safety valve (SSV) was installed to provide positive shutoff protection in the event of a catastrophic well control incident. SSVs are required in the Norwegian North Sea for well control and to prevent the release of any reservoir fluids. Safety was further enhanced by a 9 5/8-by-5 ½-in. hydrostatic set removable production packer that provided a seal between the outside of the production tubing and the inside of the casing.

Avoiding workovers

Because most North Sea wells are completed with chemical lines in the event chemical injection is required during the lifespan of the well, a chemical injection mandrel with shear-out valve was installed to deliver production chemicals, such as scale and paraffin inhibitors. By installing the lines at the outset of the project, the operator can avoid a subsequent costly well intervention operation.

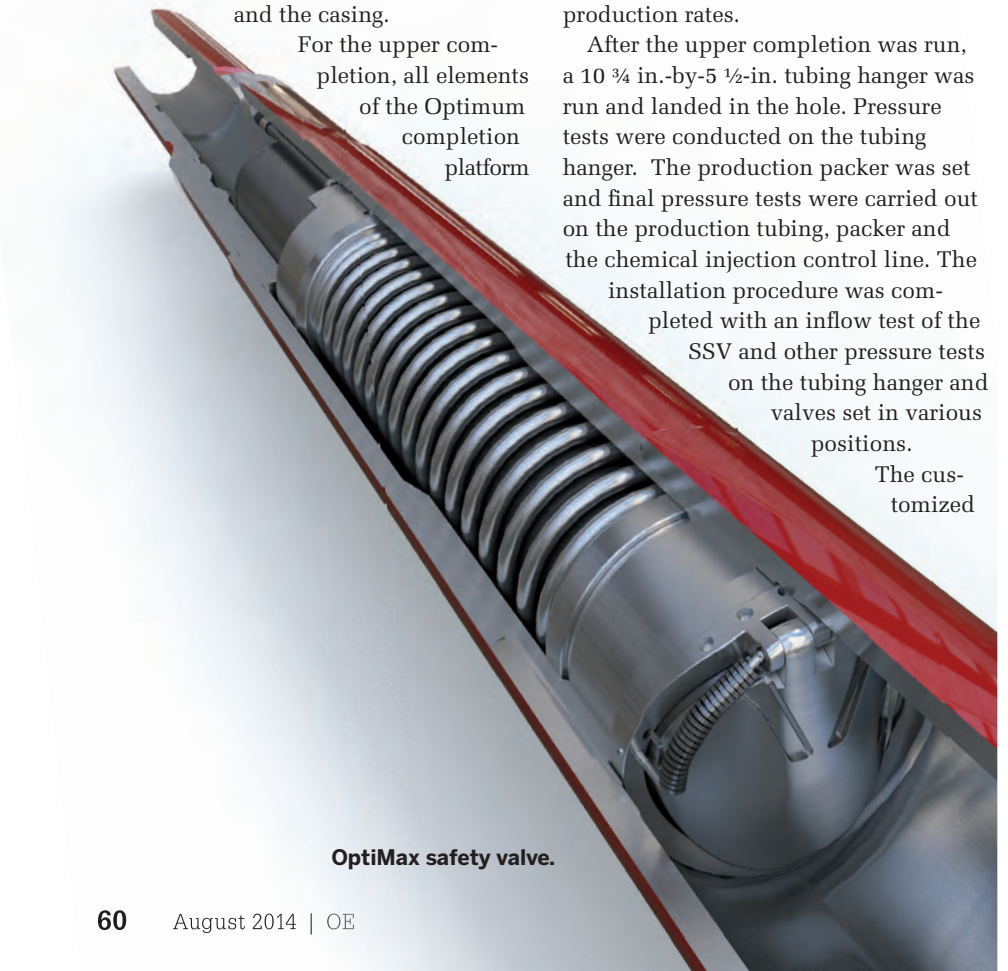
The same rationale applied to the pre-installation of two 5 ½-in. gas-lift mandrels, both unloading and orifice styles, for artificial-lift, an operation that simulations conducted during the planning phase had predicted could be needed within 12-18 months after the wells were brought online to maintain production rates.

After the upper completion was run, a 10 ¾ in.-by-5 ½-in. tubing hanger was run and landed in the hole. Pressure tests were conducted on the tubing hanger. The production packer was set and final pressure tests were carried out on the production tubing, packer and the chemical injection control line. The installation procedure was completed with an inflow test of the SSV and other pressure tests on the tubing hanger and valves set in various positions.

The customized completion system was successfully installed in both wellbores, with the entire operation finished two days ahead of schedule, reducing rig time and associated costs. In the lower completion, the standalone screens and ICD protected the sand from hot-spotting. By providing an effective seal between the outside of the production tubing and the inside of the casing in the upper completion, the hydrostatic set removable production packer eliminated the need for additional wireline work, resulting in further cost savings. Pre-installation of gas-lift mandrels and the chemical-injection system will eliminate the need for future workovers to maintain production.

The two wells were brought online 2Q 2013, and are currently producing 14,000 b/d. The success of the collaborative strategy encouraged the operator to implement the approach for additional wells in the region. The Optimum completion system has since been updated to include a radio-frequency identification (RFID) module that uses radio transmitters and receivers to control packer setting and opening/closing of sleeves, which further reduces costs and enhances safety.

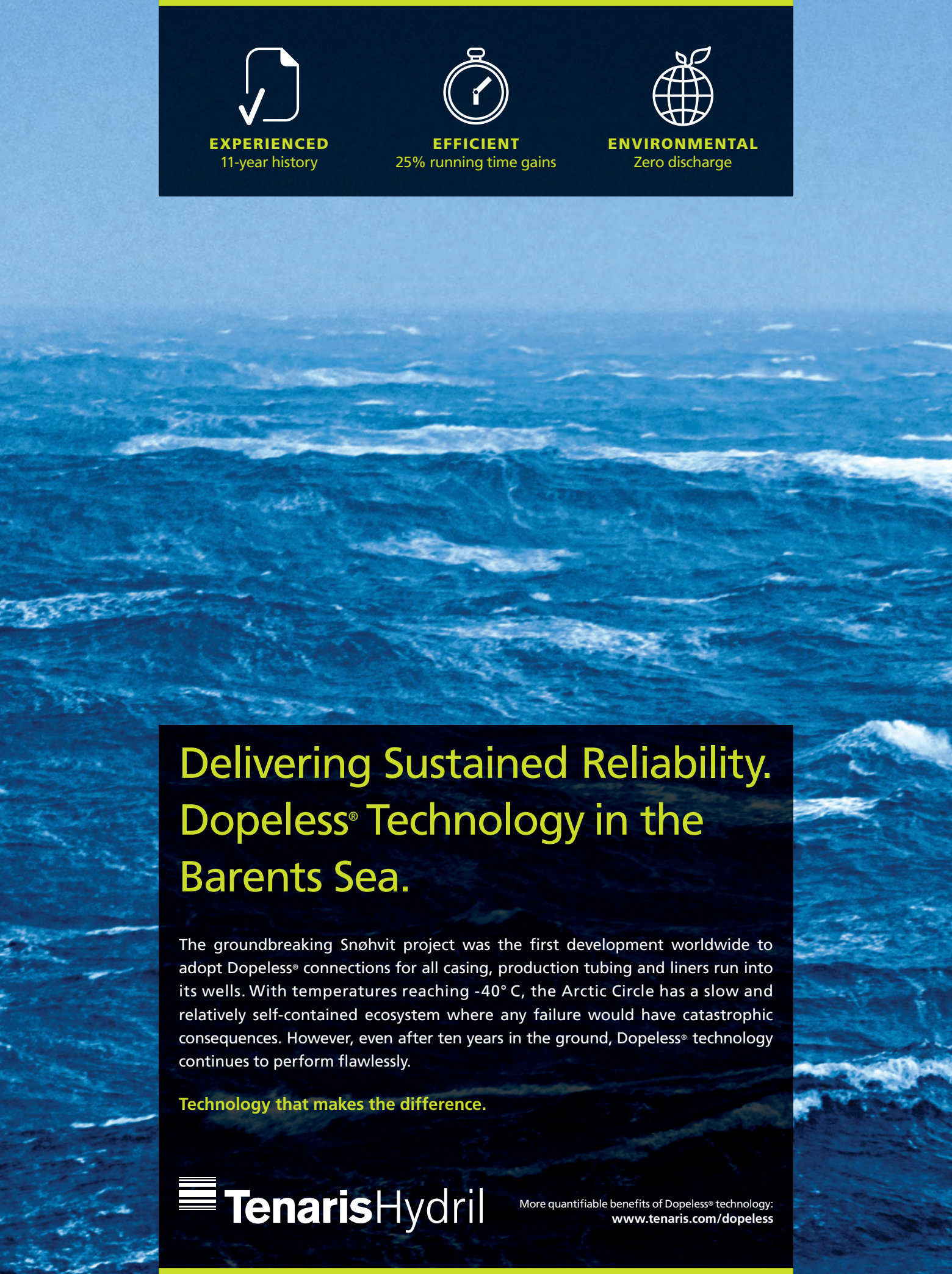
As operators continue to exploit complex and risky subsea well projects, collaborative, integrated methods that include extensive planning, strong project management and innovative application of advanced technologies are critical to maximizing production while enhancing safety. OE



OptiMax safety valve.

Yvonne McAnally *serves as global product line director, upper completion for Weatherford. Over the last 16 years, she has held various roles in engineering, marketing and business development. She has a BS in mechanical engineering from University of Houston.*

Ben Lake *serves as the global product line director, safety systems, for Weatherford. Over the last 12 years, he has held various roles in engineering and marketing. He has a BS in mechanical engineering and a MBA from Oklahoma State University.*



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Adding a secondary barrier against gas migration in deepwater environments

Secondary mechanical pressure barriers could help ease regulatory bodies' concerns around effective zonal isolation in wells.

A good cement job is the primary barrier for effective zonal isolation in wells, and is the prevalent method to protect the wellbore from the unwanted and dangerous influxes of formation fluids, solids, and gases.

In deepwater wells, cement's ability to reliably contain reservoir pressures is threatened by fluid losses to the formation during cementing operations that is impacted by higher pressures and temperatures, extended laterals, and unstable formations. An inferior or compromised cement job presents serious safety risks to the drilling rig, rig personnel, and the environment.

Enhanced reliability

Adding a secondary mechanical pressure barrier above the uppermost hydrocarbon zone will help increase reliability and safety, especially offshore. The additional barrier could prevent unintended and uncontrolled flow of reservoir fluids to the surface in the event of a compromised cement barrier, and help boost production rates, by eliminating flow that would otherwise be lost to the annulus.

Baker Hughes has developed an

The Cytadel ZX packer can be activated by dropping a magnetic signal carrier from the surface. A no-go signal can also be dropped to switch off the activation timer if needed. Images from Bakers Hughes.

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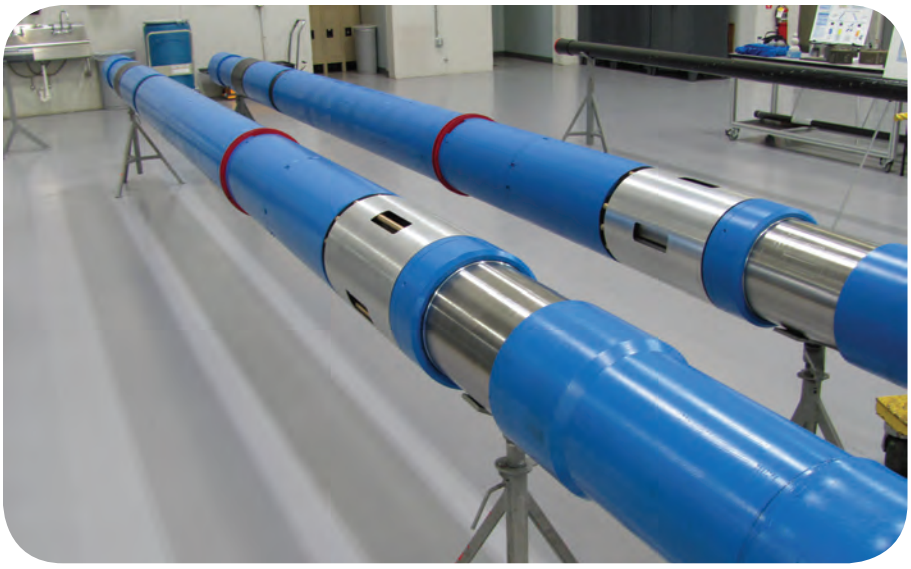

The Cytadel ZX electronically-actuated packer is designed to provide a gas-tight annular seal for the life of the well—from wellbore construction through plug and abandonment operations.

electronically actuated packer with industry-proven seal technology qualified to API 11D1 V0 acceptance criterion. The Cytadel ZX electronically-actuated packer is designed to provide a gas-tight annular seal for the life of the well—from wellbore construction through plug and abandonment operations. The system, which is typically installed as part of a long-string casing string, helps reduce HSE risks by curtailing issues associated with both annular casing pressure (ACP) and sustained casing pressure (SCP). ACP is the result of trapped fluid in or between the tubing and casing strings, which allows pressure to build as the fluid heats up during production operations. SCP is pressure that continues to build, even after being bled off at the surface. The packer's V0-rated seal prevents pressure from traveling to upper casing strings, which provides an additional level of safety assurance, particularly for those wells where bleed-off at the wellhead is not possible.

Fundamental components

The packer system comprises three design features. First, it has a solid-body mandrel with no flow paths through the body, to maintain pressure integrity and eliminate the potential for hydrocarbon communication between the casing and annulus. This enhances system reliability and prevents inadvertent activation of the packer during the trip downhole or during cementing operations. The second design feature is a seal based on the Baker Hughes' ZX technology. This zero extrusion gap seal has been V0-qualified up to 15,000 psi (1034 bar) differential at up to 400°F (204°C). These seals have been employed on liner top packers for

years to provide a pressure barrier above the liner hanger, with more than 40,000 runs to date and 99.5% reliability. The third feature is a modular electronic trigger mechanism, which is activated in one trip and eliminates the need for pressure or pipe manipulation to set the packer. The force required to set the packer is generated from either hydrostatic pressure in the wellbore, or from a pre-charged nitrogen spring contained within the packer.

Applications in shallow depths

This system is comprised of a surface-mounted acoustic signal generator and a downhole packer. It employs an acoustic trigger to set the packer. The signal generation system on the surface consists of an electronic unit that controls a pneumatic-hammer attached to the casing string. This system generates an acoustic pattern which travels along the casing until it reaches the electronic module within the downhole packer.

The electronic module incorporates accelerometers and a microprocessor, which together differentiate the incoming signal from any others that may be generated during normal operations. When the trigger signal is received, a valve opens and stored pressure energy is allowed to act against a piston, setting the packer seal in the casing. The electronics module is powered by a battery pack and is can operate in 35-300°F (2-149°C) temperatures. The electronics and battery technology in the shallow-set system have been optimized for temperatures down to 14°F (-10°C) on the rig floor.

The annular casing packer system is not limited to deepwater applications, and can be deployed as a secondary pressure barrier for conventional and unconventional oil and gas wells, both offshore and on.

In the event that the surface control unit becomes inoperable or some other condition arises that prevents the acoustic signal from being detected downhole,

a contingency preprogrammed timer sequence may be used to set the packer.

Deeper well depths

The deep-set system employs a magnetic trigger to set the packer, comprising a surface-deployed special "follow" casing wiper plug (CWP) and a downhole annular casing packer. The setting sequence is activated by a magnetic field generated by the CWP as it traverses a multitude of Hall Effect sensors in the packer's electronic module. The signature prevents inadvertent activation of the packer. After activation, the setting force is generated by well hydrostatic pressure acting upon atmospheric pistons mounted outside the mandrel.

The packer is similar in design to the one used in shallow-well applications, with the exception of hydrostatic setting pistons, replacing the compressed nitrogen module. After the onboard electronics receives confirmation of the correct magnetic signature, a trigger valve opens to allow hydrostatically charged well fluid into an atmospheric chamber to initiate the setting sequence. Using hydrostatic setting pistons is a field-proven alternative for greater well depth applications, where sufficient bottom-hole pressure is available to generate the required setting forces.

As with the shallow-well system, different triggering methods exist for the deeper well model:

1. Using the follow CWP that activates the setting sequence after a preprogrammed amount of time has elapsed to allow for completion of cementing operations.
2. Using a drop bar that employs the same magnetic signal carrier as employed on the follow CWP.
3. A contingency preprogrammed timer sequence allowing the packer to set if the follow CWP or drop bar is not detected.

The electronics module is powered by a battery pack with the same time limitations as the shallow-set tool battery. The deep well module can operate in two temperature ranges, 100-300°F (38-149°C) and 250-392°F (121-200°C). In higher temperature uses, a low-temperature battery initially powers the electronics at the surface, which becomes nonfunctional once its temperature threshold is reached downhole, before which a high-temperature lithium battery activates.

The packer seal used in both systems has the same proven, gas-tight, metal-backed, zero-extrusion gap design. The setting force drives the seal up a cone ramp, causing it to expand and conform to the casing internal diameter. The element's external tooth profile eliminates any extrusion gap, trapping the setting force between the teeth and preventing cold flow of the elastomeric cover.

Field results

The annular casing packer can be deployed as a secondary pressure barrier for conventional and unconventional oil and gas wells, offshore and on. Its first field application was unique in terms of the size required: an 18-5/8in. long string packer that is set in 24in. casing. To date, three systems have been successfully installed in offshore Sakhalin Island, Russia, wells, the first at 150m (492ft) and the second at 370m (1200 ft). The operator performed a 10 bar (150 psi) backside pressure test on the first well, and a 15 bar (218 psi) test on the second well, for 30 minutes, to confirm the seal was successfully set. The operator

continues to monitor pressure in the annulus of both wells, confirming that no buildup has occurred since system deployment. The first well is now on-line and producing 280MMscf/day. These wells were excellent candidates for field trials, as fluid loss to the formation during cementing operations is an on-going issue.

The company has also developed conventionally sized systems, including 5-1/2in. x 9-5/8in. and 9-7/8in. x 13-3/8in.

As government regulations and industry standards continue to evolve, a more intense focus will be placed on reducing annular flow prior to, during, and after completion of primary cement jobs. The long string completion systems that contain a secondary mechanical pressure barrier, i.e., annular casing packer, above the uppermost hydrocarbon zone should help to alleviate the concerns as outlined by BOEM/BSEE. OE

Basil Joseph *is an engineering manager for Wellbore Integrity at Baker Hughes. Joseph started his career in the in the automotive industry, simulating the macro dynamics of powertrain systems. He joined the oil and gas sector in 2006 as a project engineer. He holds a MSME [Master of Science in Mechanical engineering] from Michigan State University.*

Mark Knebel *is the product line manager of Wellbore Integrity and Specialty Products at Baker Hughes. He is responsible for the marketing and new product development of technologies for annular isolation, multilaterals, and solid expandables. He has had a 30 year career at Baker Hughes and earned a degree in Mechanical Engineering from Texas A&M University.*

Ammar Munshi *is a design engineer for Baker Hughes. He works in new product development within the completions and production product lines, and has been at the company for six years. Munshi trained and led the operations team in Sakhalin for the first successful field trial of the Cytadel ZX packer. He graduated from Texas A&M University with a Mechanical Engineering degree.*

Chuck Pleasants *is technology director for the Baker Hughes' Wellbore Construction product line. He has held various management roles over his 16 year career at the company, including technology manager for the Wellbore Intervention product line and manager of the Packer Customer Product Development group. Pleasants has 36 years' oil and gas industry experience. He holds a BSME degree from Texas A&M University Kingsville. He serves on the SPE 19LH task force to develop a liner hanger industry standard.*

From simulation to WRR

Offshore lifting combines heavy offshore assets with detailed analysis and product care. Elaine Maslin found out more at the North Sea Offshore Crane and Lifting Conference.

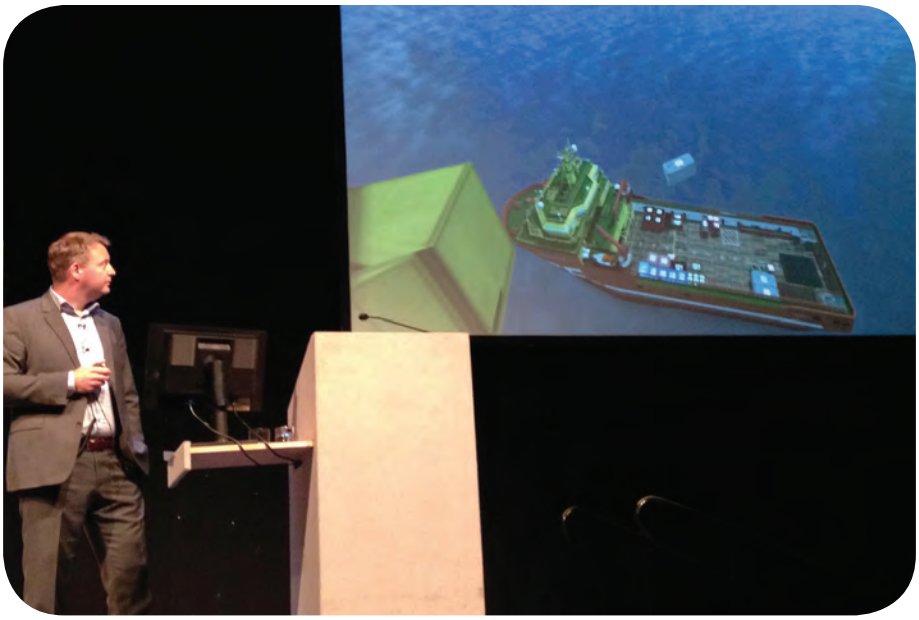

Fig. 2 Torbjorn Alstad, SMSC's chief marketing officer, demonstrating crane simulation at the North Sea Offshore Crane and Lifting Conference. Photo by Elaine Maslin.

When it comes to offshore lifting, it is usually the heavy installation vessels and barges that get most of the attention.

But, there is much more to offshore lifting operations, from lift modeling, and crane design and fabrication, to rope manufacture and certification, and rope lubrication and testing. These factors stretch right through project life-cycles and the supply chain, from rope and crane manufacture to design integration and operations.

Norway's Ship Modelling & Simulation Centre (SMSC) demonstrated how knowing how a rope or crane will perform will be beneficial during front end engineering and design, at the North Sea Offshore Crane and Lifting Conference, held in Aberdeen in late April.

Simulation

SMSC used a crane simulator to improve the crane integration on ENI's *Goliat* FPSO, which is due to start production in the Norwegian Barents Sea

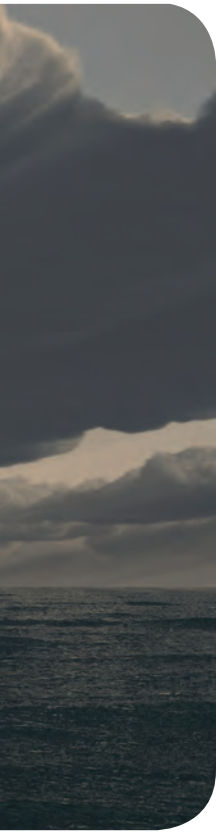

Fig. 1 ENI's Goliat FPSO.
Image from ENI Norge.

next year. The simulations, carried out in three phases during design, uncovered blind zones and challenging lift scenarios that were then able to be changed or mitigated.

Torbjorn Alstad, SMSC's chief marketing officer, told the conference that using the actual design models, SMSC developed simulator models and performed simulated operations for *Goliat*'s two cranes. This meant blind zones, where the crane operator would not be able to see, lifting corridors, and exhaust zones could be modeled and assessed and changes made to the design before construction started. Certain areas were strengthened, due to being in potential risk of being knocked. Also, which crane corridors would be best utilized for specific tasks were identified.

The changes also meant improvements in the overall design, because it identified extra lay-down area. Where changes could not be made to mitigate an identified problem, alternatives were suggested and adopted, such as focusing on the communication between the crane operator and deck personnel.

"The projects have uncovered blind zones and challenging lifts at a very early stage, enabling us to make necessary changes. It was the first time we had done something like this and I believe more companies should do this type of thing, it would save them a lot of money," Alstad says.

Slings

Computer modeling could potentially be used to calculate break loads, suggests Jan-Peter Breedeveld, engineering director, Seaway Heavy Lifting, Netherlands. He suggests that few know the actual break load and failure modes in large diameter cable laid slings, which makes defining a safety factor the key challenge.

Wire and fiber slings are used for lifting and can undergo great dynamic loads. Depending on the material, the break load is calculated in different ways. In steel rope slings, the break load in individual wires is measured and then the total rope break load calculated. But there are limited available test facilities, in terms of capacity and length, to test complete steel cable laid slings. Guidance for spliced cable laid slings was also set when the biggest slings were 140mm in diameter—now they are 400mm.

"The failure mode of spliced cable laid sling is not fully understood," Breedeveld says. "An IMCA sub-group of the crane and winch operations workgroup is working on an update of IMCA M179 and hopefully by the end of the year there will be an updated standard," he adds. But more tests are needed to better define the design factors in such cable and cutting of core

Fig. 3 Lifting operations on the GDF Suez E&P-operated Cygnus development, offshore England, this year.
Photo from GDF Suez E&P.

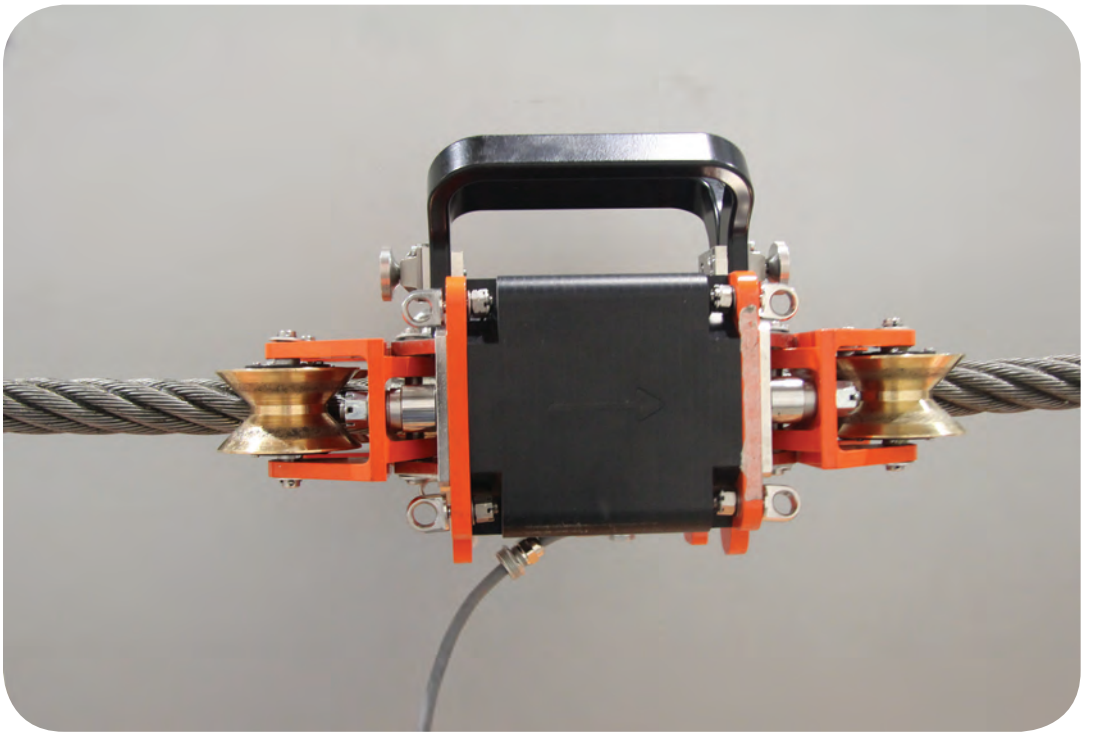

Fig. 4 Intron's Intros Auto magnetic head. Photo from Intron.

rope or better controlled splicing methods could help, he says. Further, the break load when using alternative terminations on the sling ends also needs to be understood. The new standard will not address braided slings used in the US and Asia, as they're not used in Europe, due to not being manufactured in the region.

In fiber, there is no standard describing the certification process for sling capacity, it is up to the user to do certification, although the new DNV-OS-H205 gives some guidance, Breedeveld says. "Fiber is new and different from steel. We need to know what fiber it is, what design, yarn strength, other empirical factors. Even then, how much material is actually in the string is unknown because the manufacturer will not always say. High performance fiber is a reliable product for offshore lifting operations, but the certification process is an issue," he says. An IMCA subgroup is working on a guideline for the design, use and inspection of high performance fiber slings.

Where small diameter steel or fiber rope is used for lifting applications, the break load is based on full scale break tests, which is not practical on large diameters. Can you use computer modeling to avoid all this testing, asks Breedeveld, adding that more research is needed.

NDT

Innovations in how to test wire rope offshore, on drilling rigs and offshore cranes, were presented by Moscow-based Intron and US-based NDT Technologies.

While standard magnetic rope testing remains a core necessity, an automatic rope monitoring system could provide instant information for operators, offers Intron's R&D director Dimitry Slesarev.

Magnetic rope testing has been in use for more than 30 years. Sensors measure magnetic flux leakage, caused by material discontinuity. But, Slesarev says, this type of testing requires qualified personnel, results can be complex and require interpretation, and conventional inspection methods mean having to stop operations.

"So we have developed an automatic system, that is rugged, permanently installed, simple to service and use, and giving reliable inspection results and automatic processing of data," Slesarev says.

Intros-Auto comprises a control and display unit to be handled by the operator, which will be connected to a magnetic head placed on the rope just above the winch. Intros-Auto can be used with or without distance counter, it can be also connected to external computer, for real-time monitoring and additional analysis. Rope condition is indicated on the control and display unit by a tri-color, LED system, red, yellow, and green.

Additional information is shown on an alphabetic display. Between 28-35mm-diameter rope can be tested, at 0.5-3m/s rope speed, and temperatures ranging from -40°C to +50°C, Slasarev says, with the magnetic head able to be up to 80m from the control and display unit. Sensitivity is down to one external wire, with the loss of metallic cross-sectional area (LMA) measurement accurate to less than 2%, says Slesarev. Rope condition estimation criteria is based on LMA, the maximum broken wire density value, and the increment of broken wire density relative to the previous inspection.

Roughness

Herbert Weischedel, NDT Technologies, US, says more than LMA and localized flaw (LF) inspection is needed to prevent early retirement of high-value wire rope. The firm has developed an additional method to define wire rope deterioration, called wire rope roughness (WRR). This is an aggregate surface roughness of all wires in a rope, caused by and indicating interstrand nicking, at wire crossovers, internal broken wires, and corrosion pitting, usually within the first and second layers of the rope, Weischedel says.

Electromagnetic wire rope inspection methods include LMA, a quantitative analysis, which is used to assess internal and external corrosion and wear, by measuring loss of metallic cross-sectional area, and localized flaw (LF) inspection, a qualitative analysis to detect external and internal discontinuities, such as single broken wires and corrosion pitting. However, there can be signal ambiguity in LF inspection, as, while the signal rises for single broken wires, it falls when there are clusters of broken wires.

NDT's WRR assessment uses the firm's own computer assisted rope evaluation software to do quantitative analysis of the LMA signal. To avoid downtime on facilities using rope, NDT has developed a non-contacting, continuous rope monitoring system (CRMS), incorporating WRR. OE

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Heave compensation improves offshore lifting operations

By Herman Stolle, ABS, and Lee Screaton, Screaton and Associates

In addition to allowing cranes to work safely and effectively in harsh conditions, heave compensation reduces the effect of resonance on the subsea load. Photo from Huisman.

Accurately placing heavy loads in inclement conditions offshore is a major challenge, and it is compounded when installation activity is taking place in deepwater. Rough wind and weather conditions can test the limits of installation systems, often resulting in downtime and sometimes causing damage to vessels, cranes, winches and associated lifting appliance equipment.

Growth in the subsea sector is one of the significant drivers for the focus on crane safety and capabilities in recent years. According to analysts at Infield Systems, global subsea capital expenditure and subsea tree installations are expected to double in the next five years. This growth in the number of subsea installations, coupled with the fact that much of this work will take place in deepwater, will draw even more industry attention to the subject of crane safety.

Changing conditions impact performance

Offshore installations in harsh sea conditions increase the demands on cranes because when a load is being placed on the seabed in demanding environments, excessive dynamic amplification of the load can overload a crane or rupture the hoisting cables. There is a clear need for cranes that are capable of contending safely with the rigorous demands of deepwater operations in challenging seas.

One approach to managing inclement conditions is to employ a heave compensation system – a system that is based on heave motion prediction coupled with an inversion-based control strategy. Heave compensation (also called swell compensation or motion compensation) is an increasingly common approach used in marine lifting and support systems to reduce the effect of vessel heave on a suspended load. The objective is to let a rope-suspended

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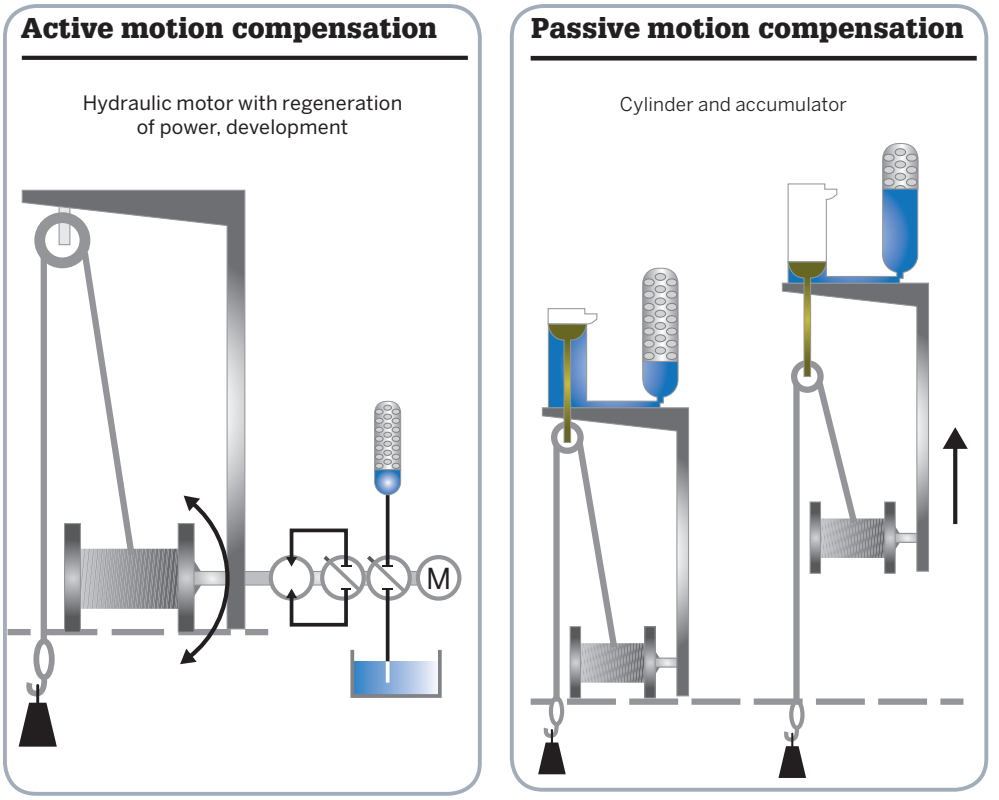

Illustrations from ABS.

payload track a desired reference trajectory in an earth-fixed frame such that it is not influenced by the heave motion of the ship or vessel.

In addition to allowing cranes to work safely and effectively in harsh conditions, heave compensation reduces the effect of resonance on the subsea load as well as the potential for shock loading during complex lifting operations. Because of the complexity of heave compensation in terms of both design and operation, most classification societies are making provisions in their rules and guidance to address the development of this technology.

Understanding installation demands

To better grasp the value of heave compensation—and the need for it in the offshore lifting industry—it is important first to understand that without heave compensation, a suspended load is subjected to heave motion in line with the vessel; when the vessel rises or falls as a result of a wave, the load on the end of the system moves by the same amount.

This motion poses challenges when the lifting system is maneuvering loads, moving them from one location to another (such as ship to ship or in subsea positioning activities), between vessels and static locations (such as lifting an offshore module onto a static jacket) or when the load must be held in place for a specific operation (such as subsea interconnection work using ROVs).

Managing heave

Typical passive heave compensation (PHC) systems, such as in-line cylinder/sheave systems or hook-mounted pre-pressurized cylinder based systems work like shock absorbers. They are simple closed-loop systems with little or no requirement for an electronic control system. Most PHC systems can be considered failsafe because they do not require an external source of energy to operate.

While PHC systems can dampen the effects of heave (i.e., reduce the effects of resonance during deepwater subsea lifting), they are not as accurate for most operations as active heave compensation (AHC) systems. Most PHC systems require a specific pressure in an accumulator system that is calculated on a load-by-load basis, meaning that new calculations are required for each differing load scenario. PHC typically cannot be used in situations where the load changes, such as in subsea coring activities where the deployed weight is not the same as the recovered weight.

As AHC implies, the compensation system predicts the vessel motions using instrumentation, primarily a motion reference unit (MRU), and operates a system to raise or lower the load so as to reduce or eliminate the vessel heave motion. Typical AHC systems are winch-based or cylinder/sheave based. In some cases, this takes the form of a PHC system with an active element. There also are methods that change the geometry of the overboarding sheave support through the use of a crane boom or A-frame, but this approach is not very common for lifting. It is used much more commonly in personnel transfer systems.

While AHC systems are considered the most effective solution for controlling a load, they require substantially more system complexity to achieve full operation. It is important to understand that AHC cannot simply be added to an existing crane or lifting system. It must be designed into the crane, taking into account such considerations as:

- Increased fatigue loading in structures
- Wire routing (as AHC significantly reduces the fatigue life of wire rope)
- Sheave design (low friction bearings, heat dissipation)
- Power consumption and control or dissipation
- Cooling

A typical cylinder-based AHC system consists of one or two sets of cylinders, two sets of wire rope sheaves (one static, one moveable), an MRU based control system and an HPU/hydraulic control system, usually including an accumulator bank for kinetic energy storage. One set of sheaves is statically mounted on a support frame, and the other is attached to the cylinder sets. The winch wire is fed from the winch drum, around both sets of sheaves, then to an over-boarding arrangement. The vessel motion is compensated by the two sets of sheaves moving closer together or further apart as dictated by the cylinder systems, which in turn lengthen or shorten the deployed wire rope.

A typical winch-based AHC system consists of a single drum winch, an MRU based control system and an HPU/hydraulic control system (usually including an accumulator bank for kinetic energy storage). Electric drive is gaining popularity where environmental

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issues are a key design driver, but while electric drive or a mix of hydraulic and electric drive can be use, the most common arrangement is for a purely hydraulic system. The vessel motion is compensated by the rotation of the winch drum controlled by the instrumentation arrangement with input from the dedicated MRU.

There also are geometry-based systems that use cylinders or some other mechanical means of manipulating a mechanism to position a load. As in the PHC and AHC systems, this type of system has an MRU based control system and an HPU/hydraulic control system that usually includes an accumulator bank for kinetic energy storage.

Pushing technology limits

The demand for heave compensation in most areas of lifting operations is providing fertile ground for new technology developments such as fiber rope, battery systems and electrical energy storage.

Fiber rope offers many advantages to heave compensated lifts for deepwater operations because fiber rope is neutrally buoyant. When wire is deployed by a subsea lifting system, the weight of the wire contributes significant additional weight to the hookload, which must be managed by the crane. Using fiber rope reduces the overboard load, which results in both load control and power consumption advantages.

While advances are being made in fiber rope design, lithium ion battery systems are improving in terms of energy density. Today, automotive technology allows for multiple kilowatts of storage in a relatively small battery. Transferring this technology approach to offshore installation operations is allowing the development of subsea AHC lifting systems that can be placed on the seabed instead of aboard a vessel. Locating the lifting system closer to the load nearly eliminates the impact of the deployed wire.

Improvements in short-term energy storage, such as kinetic energy recovery systems (KERS), have great potential for application in AHC systems, specifically in the control and dispersal of regenerated energy in systems with electrical drives. One drawback of AHCs with electrical drive systems is that the typical method of burning off regenerated energy is to use water-cooled resistors, which wastes energy that otherwise could be put back into the supply system. In hydraulic systems, regenerated energy can be stored in accumulators and reinjected into the supply system, thereby reducing overall power requirements. While it has not been achieved to date, it might well be possible to use KERS to mimic this reinjection method for electrical systems, which could widen the acceptance of electric drive for high-power AHC systems.

Contending with challenges

New challenges are becoming evident as more lifting operations adopt and adapt these systems. Such issues include multifall/multipart lift rigging arrangements and catenaries in deepwater lifting operations.

When a lifting arrangement has more than one part or fall of rigging, the relationship between the position of the hook and the length paid out or in by the lift winch is halved. For every 1m (3ft) of wire paid out or in, the hook moves 0.5m (1.5ft). This ratio halves for each additional part or fall of rigging. Because most AHC systems function through lengthening or retracting the lift wire – invariably

before the multifall/multipart rigging arrangement – they have to work twice as hard for each part or fall. In general, a typical winch based AHC system is of no real practical use on a system with more than two-part/fall rigging. Currently, multifall/multipart rigging arrangements with more than two falls/parts are compensated using hook-mounted PHC systems. Regardless, PHC is not as accurate or adaptable as AHC.

Another significant challenge is the impact of a naturally occurring catenary in the lift wire of deepwater operations. As has been found on recent >2000m (6560ft) subsea operations, lift wires rarely sit vertically in the water column. Slack in the wire is not eliminated by the weight of the load alone. The bend in the line creates problems for vessel-based compensation systems because when they retract or extend the wire to compensate for vessel heave, a percentage of the movement intended for the hook based load is lost in the slack of the wire. When the system takes up the slack, the result can be sudden jerky motion at the load, shock loading through the system, confusion in the AHC control system and poor synchronization.

Classification requirements evolve

To keep pace with the rise in the use of heave compensation techniques, classification societies are working to provide guidance in key design areas, including:

- Basic design requirements and safety factors for general fatigue life, structure, electric/ hydraulic components, lifting wires and umbilicals, including routing
- Considerations for shock and amplified structural loading due to poor synchronization between vessel heave and the reaction of the heave compensation system
- Overload mitigation should the heave compensation system fail
- Testing techniques
- Baseline design features, such as key instrumentation and software features.

The role of class services continues to change as the offshore industry advances into deeper water and more exacting operating environments. As E&P activities move into more challenging areas, classification societies will continue to transform to answer the industry's changing needs. As operating conditions change, the ultimate goals of the class society remain the same – to help increase uptime, improve productivity and safely expedite advances into technology frontiers. OE

Herman Stolle *serves as ABS's principle engineer for offshore technology and business development, in Rotterdam, where he has responsibility for general issues on offshore lifting appliances and relevant (subsea) crane applications. Stolle has worked in Norway for 17 years in design and management related to offshore cranes and lifting. He attended the Polytechnic Academy in Enschede, The Netherlands.*

Lee Screaton *is a Houston-based consultant specializing in offshore equipment and handling systems. After more than 20 years of design, operation and management roles in the oil, gas and subsea telecoms industries, he now regularly consults on existing and future equipment designs for both surface and subsea operations. Lee holds a BEng (Honors) in Electronic and Electrical Engineering from Aberdeen University in Scotland.*

Meeting lifting standards

Protea has designed its largest crane to date for Statoil's Heidrun FSU, a project that will aid the life extension of the Heidrun field.

Statoil is investing in the infrastructure of its Heidrun field in the North Sea, hoping the return will be an extension in life of the field until at least 2045.

One key expenditure has been in a new floating storage unit (FSU) for the field, currently being built by Samsung Heavy Industries in Korea. It will replace an existing two-buoy loading system on the field, from which purpose-built shuttle takers were used for offtake.

Heidrun was discovered in 1985 by ConocoPhillips in the Norwegian North Sea and has been producing oil and gas since October 1995 from a floating tension leg platform with a concrete hull.

A total of 76 wells are planned on the main field, including 51 producers, 24 water injectors and one gas injector. The north flank of Heidrun was brought onstream in August 2000.

Samsung Heavy Industries is building the new FSO on Geoje Island, Republic of Korea. The unit is expected to be on location at the Heidrun field 1H 2015.

The new permanently-manned FSU will have a 30-year expected design life and is scheduled to be on location from early 2015. It will be permanently moored to a buoy, with oil offtake via shuttle tankers.

The FSU includes a new 55ton safe working load (SWL) crane, designed and built by Poland's Protea, which has offices in Norway and fabrication facilities and offices in Poland.

"Statoil required a weight-efficient, high-performance offshore pedestal crane, that complied fully with EN13852-1, Crane N Notation and NORSOK regulations," Tomasz Paszkiewicz, Protea's CEO, says.

Cranes of this capacity and outreach are typically of a lattice boom construction, but for this application, Statoil specified a box boom type to ensure the crane was as compact as possible with the shortest luffing range.

As box boom cranes are generally heavier than a lattice boom equivalent, one of the key technical challenges was to optimize its overall weight. This required detailed analysis of the crane's structure, using software developed by Protea, together with shell element analysis and bar element analysis. This process allowed Protea's design to comply with code and meet the overall weight target, coming in at 165ton, including the pedestal and the staircase, or 125ton without.

Two high capacity hydraulic rams are used for luffing the boom, reducing the overall height of the crane and making it suitable for use on offshore platforms where there are height limitations.

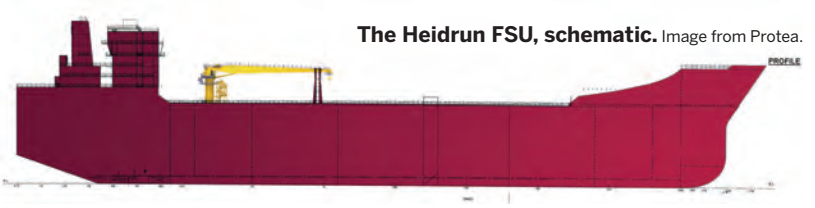
The crane's total hoist height is 80m, with hoist speed in four-fall configuration being 18m/min (SWL 50ton), and 42m/min in one fall configuration (SWL 10ton). The outreach is up to 40m, with an unlimited 360° slewing range at 0.72rpm. Full boom luffing can be achieved in 80 seconds.

The crane met EN 13852-1 Offshore Cranes standard; DNV GL N Class standard; the latest NORSOK regulations, and Statoil's internal requirements, Paszkiewicz says, making it "probably the highest specification offshore crane that has been delivered to date."

While Protea has already designed a number of Ram luffing cranes, including 22ton SWL cranes for a pipelay vessel and a 33ton SWL riser handling knuckle boom crane for a semisubmersible drilling rig, this is the largest capacity ram luffing crane the firm has built.

Protea was founded in 2001 by Paszkiewicz and subsequently merged with engineering firm NTD Olesno in 2004, before opening a manufacturing and assembly facility in Ligota Gorna, Poland in 2008. The production facility was expanded in 2013, with the addition of a 26m-high assembly hall. OE

Statoil's Heidrun platform. Photo from Statoil, by Harald Pettersen.



The Heidrun FSU, schematic. Image from Protea.

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Bringing decommissioning to life

Sarah Parker Musarra examines decommissioning in the Gulf of Mexico, and how these facilities can become fixtures in the surrounding marine life.

Requirements on decommissioning in the US Outer Continental Shelf (OCS) have existed before any lease was ever signed for hydrocarbon exploration in its federal waters. Passed on 7 August 1953, the Outer Continental Shelf Lands Act (OCSLA) defines the OCS as "submerged lands [under US jurisdiction] lying seaward of state coastal waters (3mi. offshore)." The Secretary of the Interior was also made responsible for "the administration of mineral [which is defined as oil, gas, sulphur and others] exploration and development of the OCS."

In 1954, one year after the creation of the OCSLA, Lease OCS 0404, the first lease ever to be issued in the US OCS, was granted for a five-year lease on property off Louisiana in the US Gulf of Mexico. At that time, the US Energy Information Administration places total offshore oil production at 133,000bo/d. Then covered in Lease Section 6, the ljjessees had one year upon expiration or early termination of the lease to remove "all devices, works, and structures."

"As long as we've been leasing and installing facilities on the federal OCS we have had a decommissioning mandate on every single one of them," T.J. Broussard, chief, Environmental Enforcement Branch of the US Bureau of Safety and Environmental Enforcement (BSEE), says, explaining that even minor structures must abide by the same decommissioning mandates.

"We didn't want taxpayers to be liable for having to remove components that were put in place by the operators, or by the people under Right-of-Use-and-Easement or Right-of-Way agreements," he says.

US oil production rates have changed: It is about ten times what it was in 1954, with the US EIA placing offshore oil production at 1.3MMbo/d in 2013. However, in terms of decommissioning regulations, not much else has changed since that time. Now covered under Lease Section 22, lessees still have one year to remove everything – "to pull the topside, remove the jacket assembly and remove any other obstructions on the seabed that could have occurred during your lease operations," as Broussard explains.

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Decom in the GOM

According to BSEE's most recent data, there are currently about 2600 facilities —from floaters and jacketed platforms down to caisson/well protectors—in the Gulf of Mexico. Based on the number of permits received, Broussard expects removal in 2014 to follow the trend of the last few years, with about 200-250 facilities due to be removed from the Gulf.

"The rate varies because not only do you have operators whose leases are ending under the regulatory timeframe of one year, but you have operators who choose to remove platforms for financial or other reasons," Broussard explains.

When it is a simple, standard decommissioning for even a four- or six-pile jacketed facility in the shallower waters on the OCS (300ft or less), decommissioning can be made quick work, with Broussard saying that a project without issues could be pulled out in a week or two.

Multiple factors influence how quickly the facility can be decommissioned, from

Reef site High Island 389, in Galveston's Flower Garden Banks National Marine Sanctuary. Photo from Chris Ledford / Texas Parks and Wildlife Dept. Artificial Reef Program.

how complex the project is down to the working order of the tools.

"I've seen it be as quick as two days," he says. "Or I have seen a four-pile structure can take a month because cutters weren't working, or because the operator wanted to use explosives and animals wouldn't leave area."

Another factor: water depth, and, most especially, the complexity of the projects necessary to operate in such depths.

The Gulf of Mexico, which the US Environmental Protection Agency (EPA) identifies as the world's ninth-largest body of water with a mean water depth of 1615m, is home to the world's ultra-deepwater projects. As an example, what will be the world's deepest production facility is located in the Gulf of Mexico.

Shell's Stones oil and gas development sits 320km off the coast of New Orleans in approximately 2900m of water; its first phase is due to enter production in 2016 through a US$1 billion floating production storage and offloading unit.

The EPA says that waters deeper than 3000m account for 20% of the water in the entire Gulf of Mexico.

Mooring and anchor facilities are used in deepwater projects that need removal. Divers or remote-operated vehicles (ROV) are required to unfasten equipment from the seafloor, which can affect the length of time of the decommissioning.

"Some of the deepwater facilities, like spars and tension leg platforms, are installed on the federal OCS in multiple pieces as they are commissioning. In certain cases it is more difficult to decommission it and take it apart because it was made to be installed in one primary manner," he says. "[For] a large facility like a spar—once you decommission it, it's a large piece of steel you have to do something with."

While a material barge can be used to unload and shuttle facility pieces back to shore in shallow water projects—of which BSEE has seen more than 3000 removed since the start of the OCS program—it's not that easy in deepwater.

What arrived via barge for commissioning cannot always be reloaded onto one during decommissioning, so it a barge might have to be deballasted and towed back in for scrapping. In addition, particular severance tools and vessels are needed that are not as readily available as the derrick barges or material barges used in shallower waters.

On top of that, Broussard says the ROVs employed might require a separate vessel on deepwater removals.

"[Deepwater decomissionings] require a lot more upfront planning on behalf of the operator," Broussard says. "For deepwater projects operators will be in our office 1-2 years, if not longer, in advance to go over their primary plan, or look for any problems or things BSEE would like them to focus on."

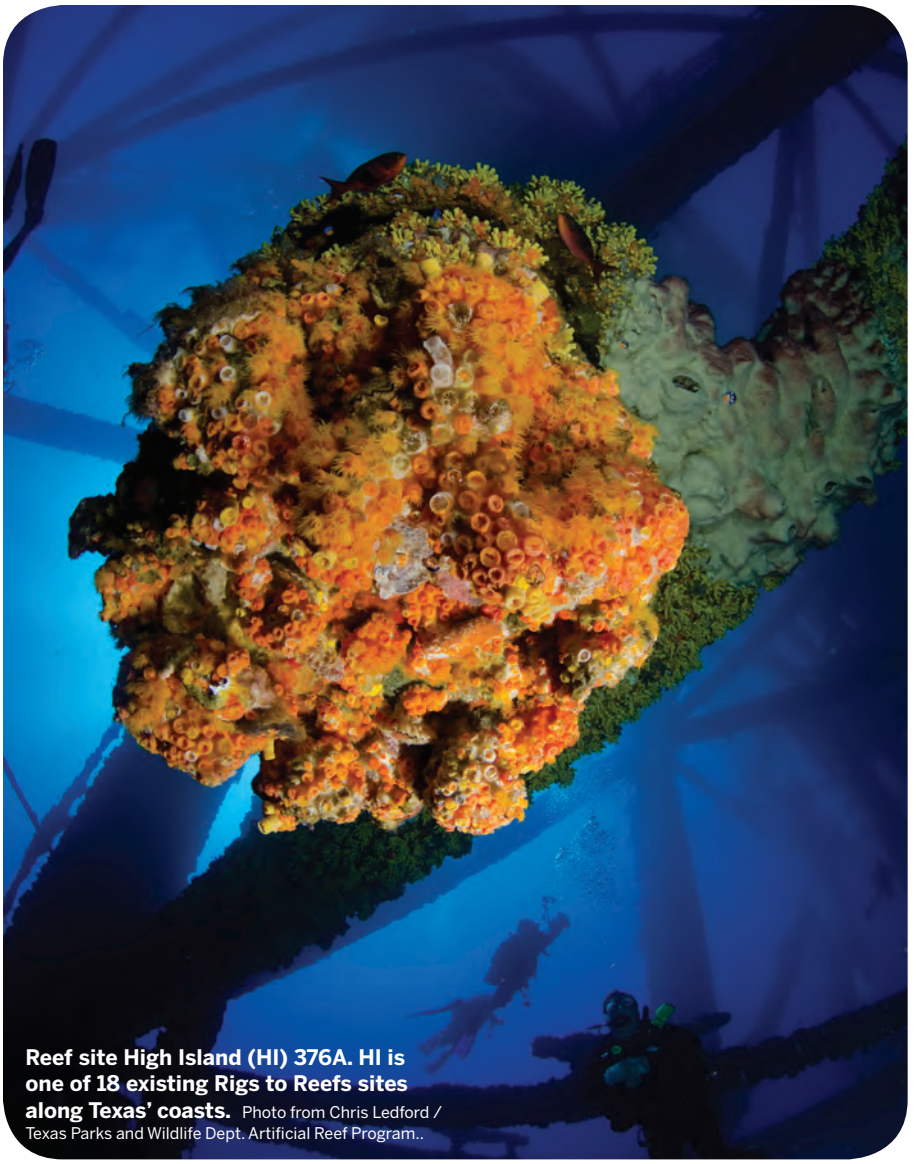
Decommissioning is not the only option in the Gulf of Mexico. The secondary option is less of removal option than one of renewal: reefing programs.

Rigs to Reefs

The final disposition, that is, how the materials will be removed, must be included on a lessee's permit application. Beyond decommissioning, operators can also choose to donate their facilities to a reefing program, which began to crop up after the National Fishing Enhancement Act of 1984.

Around that same time, which coincided with the first wave of offshore structures needing decommissioning in the 1970s-1980s, the Mineral Management Service (MMS), as BSEE was known then, conducted studies that found that the jackets on these facilities were "durable, stable, and complex. Biological ecosystems developed on them over time when doing resource extraction," Doug Peter, Rigs to Reefs

Marine life in reef site High Island 317. Photos from James Sinclair / BSEE.



Reef site High Island (HI) 376A. HI is one of 18 existing Rigs to Reefs sites along Texas' coasts. Photo from Chris Ledford / Texas Parks and Wildlife Dept. Artificial Reef Program..

coordinator for BSEE, explains.

Among the Act's findings were that "US fishery production annually falls short of satisfying US demand," and that "properly designed, constructed, and located artificial reefs in waters covered under this title can enhance the habitat and diversity of fishery resources."

This act "prompted the states to develop for artificial reefs programs," Peter says. "The MMS followed suit shortly thereafter and allowed departures from the normal removal of platform after their use of extracting oil and gas."

After some trial structures were towed to Florida for reefing between 1982 and 1983, Rigs to Reefs was formalized as a program in 1985. The two states with the majority of structures in their waters created programs first: Louisiana's state program began in 1986, with Texas following in 1990. The other states that channel into the Gulf of Mexico also started programs throughout the 1990s.

While there are copious structures ribboning the Gulf's waters, not all of them make the cut for a federal or state reefing program. Peter places the number of structures reefed to date in the Gulf of Mexico at 455.

There are a lot of single-pile caissons and structures in shallow water in the Gulf of Mexico that would automatically be disqualified from Rigs to Reefs on size alone. While the Gulf of Mexico is known for its deepwater, the US EPA says that the waters of the continental slope are just 200-300m. Rigs to Reefs also generally requires a three-pile structure at minimum. If a structure is in an area with other conflict uses, it also would not be able to be reefed.

Just like the reefs themselves, the process is a delicate one, where a missing piece could cause the entire process to crumble. "There are a number of things that actually determine if a structure is suitable, and there are also the dealings between the state program and the operator that own the structure. Any one of those puzzle pieces could make or break the reefing of a structure," Peter says. "There's a lot of intricacies to this, so not every structure is suitable. It also requires buy-in from the operator that owns the structure because it's ultimately their decision whether they want to participate in the state program. The state program has to accept liability of the structure that's actually being reefed."

BSEE's Rigs to Reefs program evaluates suitability, and then turns it over to the state program to cooperate on final placement. The size of the reefing area varies, with Peters offering the examples of an average size of a reef site off Texas being around 40 acres, while Louisiana's average reef sites are around 360 acres.

Site composition also varies. Dale Shively, artificial reef program leader for Texas Parks and Wildlife Dept. says there are many options at the program's disposal. "Sometimes we can present scenarios where it works out better than [the companies] originally thought," he explains, urging companies not to be "closed-minded" when looking at disposal options. "We can work with the US Army Corps of Engineers and the US Coast Guard to see if a shallower clearance is available... We can perform a partial removal, in which the platform base stays in place on the ocean bottom with the top next to it; topple it in place; or tow the platform to an existing reef site."

As far as permitting is concerned for reefing programs, Broussard says that, "only a few components on the permit are different. We want to ensure that the facility or jacket assembly is compatible with the program and won't introduce any additional impacts or issues when it comes to the OCS. We don't want it to break loose and damage infrastructure, and we don't want it to have any contaminants."

Peter points out that these facilities can sometime offer the marine life more than Mother Nature herself: the reefed structures offer high relief, meaning that they extend further in the water column than the natural structures.

"There's quite an ecosystem that develops around some of these structures," Peter says. "They provide stable, durable, complex habitats that allow things to thrive that wouldn't be there because of the sand and mud bottom in the bottom of the Gulf." OE

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P&A problems

Plugging and abandonment accounts for about 43% of decommissioning costs. Operators and service companies are looking at ways to reduce the bill. Elaine Maslin reports from the 2014 Decom Offshore conference.

Using 15 rigs full time, it would take 40 years to plug and abandon (P&A) all the current 3000 and expected future wells on the Norwegian Continental Shelf.

It's a striking statement, made earlier this year by Martin Straume, lead P&A engineer for BP in Norway and chairman of Norway's Plugging and Abandonment Forum (PAF), under industry body Norwegian Oil and Gas.

The UK sector is facing a similar challenge. The overall decommissioning bill for the UK North Sea has been estimated at about £35 billion, but "on recent well abandonment performance, costs could escalate and easily exceed £50 billion," according to Sir Ian Wood's UKCS Maximizing Recovery Review, published in February.

P&A is expected to amount to 43% of the overall estimated decommissioning costs, according to an Oil & Gas UK survey conducted last year. A total 5000 wells are expected to require P&A on the UK Continental Shelf (UKCS). In just the next 10 years, some £4.5 billion is expected to be spent on P&A operations on about 800 wells, 480 in the central and Northern North Sea, and 300 of those on platforms, according to Oil & Gas UK's 2013 Decommissioning Insight.

"Train wreck" wells

A major part of the challenge is the condition wells are in. Not all wells are the same and one in four are a "train wreck," says Joost Perquin, director of International Strategy Offshore Services, Tetra Technologies. "We have to be cognizant that not all wells are the same," he told the June's 2014 Decom Offshore conference in Aberdeen.

Perquin puts wells into four categories, according to their abandonment complexity. Category one are wells with good integrity and no limitations. Category four wells have had sustained casing pressure due to hydrocarbons or overpressures, or are without cemented casing at barrier depths.

Of the 300 central and northern North Sea platform wells, he says, "some—one in four, or 20%, anecdotally—are a "train wreck" (category four). 50% have good integrity (category one) or can be accessed through coiled tubing or a hydraulic work over unit (category two)."

The costs can be high. An average category one well costs about £2.1 million to P&A, rising to £9.3 million for a category four well, he says. Category one wells take about seven rig days and category four 31 rig days, Perquin says, with the cost of using a rig for P&A operations standing at about £300,000/d.

So what can be done? Straume's comments were made to highlight the size of the P&A challenge, and incite the supply chain to find ways to find new rigless solutions to make the process more efficient and cheaper, and free-up rigs for E&P drilling.

Perquin agrees, and suggests finding alternatives to using a mobile drilling rigs for P&A operations, such as using lift boats, subsea P&A, platform-based rigs, or using a dive support vessel (DSV) or utility based boat—all already used for P&A operations outside the North Sea, he says.

"Rigless P&A can be done on the platform or off a lift boat, jackup, or DSV. You can also get access to subsea wells through riserless intervention," he says, adding that it is already being done in the Gulf of Mexico. Perquin set out a rigless P&A cost comparison between the UK and Gulf of Mexico, see table.

P&A cost comparison table

Equipment needed: Double drum wireline unit, cement blender, pump and PU, a storage tank, plus auxiliary equipment. A nine-man crew for 24-hour operation.

	Gulf of Mexico	UK North Sea
Spread rate per day	US$35,000	£100,000
Consumables per well	$30,000	£75,000
Time needed	4-5 days	6-7 days
Total P&A cost*	$200,000	£750,000

*Excludes overhead and support cost

Alternatives

Companies are marketing alternatives. A joint venture between Malaysia-based Bumi Armada and Fugro (51%/49% respectively) has introduced the *Fugro Synergy* as a well intervention vessel, which could "take P&A off the critical path" and free up rig time, Mitchell Pinkard, business development manager,

The *Fugro Synergy*. From Fugro Drilling and Well Services

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Fugro Drilling & Well Services, told the conference. It has a R190 Seacor drilling rig and Varco TDS 250 top drive.

There are others offering alternative services too. FMC Technologies and Edison Chouest Offshore joined forces in 4Q 2012 to create FTO Services, offering vessel-based services for greenfield and brownfield installation, field inspection, maintenance and repair (IMR), and well intervention, including P&A. In 4Q 2014, FTO will take delivery of its first riserless light well intervention deepwater stack from FMC Technologies. It will be able to carry out well intervention at up to 6500ft water depth. The stack will be deployed from Edison Chouest Offshore's new purpose-built, Ulstein X-bow design, intervention vessel, *Island Performer*.

Singapore-based Keppel FELS and Dutch firm Seafox Group recently announced a partnership to create a purpose-built accommodation jackup with well intervention and P&A features. It will be based on Keppel's KFELS K Class design, and will be suitable for the Norwegian North Sea environment.

For platform-based operations, Archer has designed a modular drilling package (*OE*: June 2014). The vertical drilling rig 400.2 offshore modular rig, Archer Topaz, will be deployed in the Norwegian North Sea, on a program for Statoil on the Heimdal field, mobilizing in August, and to be operational by November. It will be used to permanently P&A 12 gas wells on the Heimdal platform on a 34-month contract.

Keppel FELS/Seafox's jackup P&A concept. Image from Keppel Offshore & Marine.

So why is this not being done more? Speaking at the Decommissioning Conference, Roy Aspden, decommissioning projects manager, CNR International, says there's a natural conservativeness in the North Sea, because of the conditions, I.e., weather, but he thinks rigless operations can be done.

Murchison

CNR recently started its own major decommissioning campaign on the Murchison platform, in Block 211/19, in the Northern North Sea. The 24,500-tonne topside has modules for drilling, production and accommodation, supported on a 27,600-tonne eight-legged steel jacket in 156m water depth. First oil was in 1980, and production was shut in on 28 February 2014 with permanent cessation of production (CoP) on 31 March.

Murchison has 33 platform wells and one subsea well. The P&A program will be broken into three phases, outlined by Aspden:

- Rigless (wireline) operations, with an average six-day duration, to place reservoir barriers, displace hydrocarbons and punch/cut the tubing in preparation for rig-based operations.
- Rig-based, averaging 12 days per well,

CNR International's Murchison platform.
Photo from CNR International.

to place additional reservoir barriers, where required, recover tubing, ASV and casing, where required, install intermediate barrier and environmental plug.

- Conductor recovery, averaging 6.2 days per well, involving cutting and recovery of the surface casing string and 26in. and 30in. conductors.

Murchison has an 11X3 wellbay layout, lending itself to simultaneous operations, Aspden says, and many of the wells, which were mostly in production or being used for water injection before CoP, have been re-completed or sidetracked and the operator has good integrity knowledge.

The first, rigless phase started 31 October 2013, and rig-based P&A operations started in April 2014. Conductor removal operations are due to start in April 2015 and run through to December.

There are other challenges to P&A operations. If platform-based equipment was better maintained, it could be used when it came to decommissioning, instead of having to be upgraded, which could save costs, Steve Andrew, asset closure head, ABB, told the Decommissioning Conference. This includes drilling equipment, but also accommodation and access facilities, which would need to be used. In addition, if equipment is well maintained, it could also potentially be reused or sold on, further saving costs. Three years from CoP there needs to be a "maintain and protect asset value" ethos, and identification of waste streams as early as possible, Andrew says.

New regulator to take more interest

According to Bill Cattanach, head of Pilot secretariat, at the Department of Energy and Climate Change, there also needs to better industry planning and collaboration. Changes could be coming, via a new regulator for the North Sea, prompted by Sir Ian's Review. The new regulator is likely to take more interest in decommissioning, the cost of which the UK tax payer pays 50-75%, through tax reliefs for operators, Cattanach told the conference.

According to Sir Ian's review, most of the attention, to date, has been on developing decommissioning processes, methods to estimate costs, and managing the build-up of current activity. "There has been a lack of focus on macro-cost reduction or innovation," it says.

A priority for the new regulator will be to set up a decommissioning forum and to set a target to "radically reduce the cost of decommissioning over the next decade." The Review says technology will have a key role to play in helping to tackle the existing "significant backlog of well abandonment," as well as in considering the piece-small approach, looking at cutting technologies, and using light well intervention vessels. In addition, new late-life business models should be considered, it says, and the regulator should, with industry, "investigate game-changing decommissioning concepts, which could radically change the value proposition." OE

The roadmap to retiring

More than £40 billion is expected to be spent on decommissioning in the next 25 years in UK waters alone. Dorothy Burke looks at how viewing decommissioning as new phase in an asset's life-cycle could help better plan these complex projects.

Knowing where you are going and how you are going to get there is important. Whether going on business trip, or executing a multi-million pound contract, the outcome of the journey and its ultimate success is due to preparation and planning.

A Decision Roadmap ensures you make sound decisions about every stage of that journey. You need to identify the viable options and take actions to progress the project, but you must choose the right options based on sound reasoning, rather than being left with only one option due to poor planning. Understanding what is important, gathering the correct information and involving the right people is vital.

Since the 1970s, through careful planning and collaboration, the North Sea oil and gas industry has steadily developed into one of the strongest and most highly regarded clusters in the world. For years, platforms have been maintained and modified to provide the very best yield, but, it is now recognized that a growing number of oil and gas assets have either reached, or are approaching, the end of their economic life. In accordance with current regulations, assets will have to be decommissioned and removed. This presents challenges for the owners and operators, while offering major business opportunities for engineering consultants, contractors, and service specialists.

Offshore decommissioning is a complex series of activities, each calling for its own level of skill and expertise. From operations to communications, engineering to legislation, each strand is vital. Understanding how a platform was installed, how it was operated, and the expectations for when it reaches the end of its life is a collaborative process which requires transparent knowledge share.

Decommissioning is seen by many as reverse engineering, essentially deconstructing an installation. However, it is being increasingly recognized that decommissioning is actually very different from the capital investment projects and not suited to the same "tried and trusted" procedures and process.

The typical life cycle of an installation follows these eight key stages (see image below):

The critical questions are; at what point in this cycle is consideration given to decommissioning and when are plans best put in place? Many believe that decommissioning projects need to be managed differently and the traditional "appraise, select, define, and execute" approach does not adequately address the unique features of decommissioning.

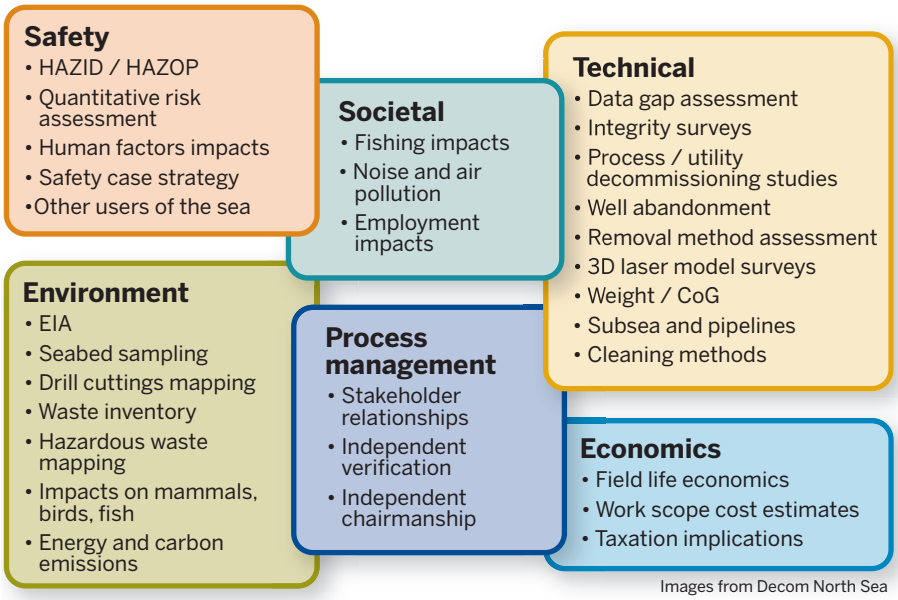
A series of workshops facilitated by Decom North Sea (DNS) with a group of operator and contractor members, is discussing decommissioning or "retiring" an asset as a new phase in its life-cycle, rather than treating it as a new project. The proposed retire-phase recognizes the transition from operation to decommissioning. This distinction, while seemingly small, will enable the industry to look at things differently and help plan, communicate, prepare for, and manage the decommissioning effort.

The transition period from operations to decommissioning occurs over a period of time. Each asset is unique, but the same options require consideration. Not all elements of an asset mature at the same time or pace; some are complete prior to cessation of production (COP), while others occur years after COP. This results in multiple, targeted assessments of readiness, with a complex series of activities to be carried out in a certain order against a predetermined timescale.

When preparing for decommissioning, there are a number of options that the operator must consider. These are

The decision roadmap

What's involved in preparing to decommission?



Images from Decom North Sea

summarised in a decommissioning program, which is submitted to government (the Department of Energy and Climate Change) using a standard template format, which DNS worked with industry and DECC to create.

In contrast, at the moment there are no standard planning processes or procedures in place to manage the transition from operations to decommissioning, and there is no documented toolbox for managing this series of events. There is however, consistency in the decisions that need to be made, the timing at which these should be considered, and the key enablers for decommissioning to be successful.

The aim of the initial workshops is to learn from the approaches used by different companies, identify the gaps in the decommissioning planning process, and define what tools may be useful to assist planning during the transition phase.

Elements discussed include planning for 10 years before COP, a strategy matrix, covering scope, control, contracting and technology, and a decision road map, indicating key decisions, when they need to be made and by whom. DNS believes that creating such a tool box would assist in decommissioning projects of different sizes and complexity, and would enable decommissioning teams to better scope the planning process and the impact of decision making throughout the transition phase.

Next steps are likely to be a call for workgroup members to take part in a collaborative effort to create a documented framework and develop a toolbox to address this need.

Marathon Oil is a DNS member which champions the decision quality (DQ) approach to project planning and decision making. It takes a collective consensus on project decisions, by identifying which decisions are "key," when they should be made (both their timing and their relationship to other decisions), what options are available and what selection criteria should be used. The DQ approach also establishes who should be involved in the decision making process, which has helped to initiate and manage interfaces and collaboration, as well as identify dependencies, impacts, and risks across the business.

By taking an overview of the decision making process, Marathon Oil can prioritize and focus its efforts. It believes this has helped significantly in communicating with management and other stakeholders, which in turn has led to a formal interface management and an improved way of working.

With more than £40 billion anticipated decommissioning spend in the next 10 years in the UK North Sea alone, it's clear that planning for decommissioning is critical to success and that while every asset is unique, many face similar planning challenges. DNS believes that the creation of a decision planning roadmap and toolbox could be of significant value to the industry to help map out that journey. OE

Dorothy Burke *facilitates Decom North Sea's projects and initiatives, bringing together operators, major contractors and the supply chain to collaborate on a range of decommissioning topics.*
Her previous experience covers technology, innovation, and facilitation roles/ contracts with oil and gas technology facilitation organisation ITF, the Energy Knowledge Transfer Network, the Innovation Relay Centre, and Connect.

Decom North Sea (DNS) is the industry body that facilitates this in the North Sea. Since its inception in 2010, DNS has grown to have more than 230 members, including operators, contractors, service specialists, and technology developers. The group's aim is to bring people from across the industry together to discuss opportunities and learn from one another.

Stepping-up decommissioning

The *Pieter Schelte*, at Daewoo Shipbuilding and Marine Engineering's D-Quay, Korea, having its helideck installed.

Image from Allseas.

New specialist vessels have the potential to change the face of the decommissioning sector, but will they solve all the issues activity in this area continues to face? Alan Clifton takes a look.

Decommissioning end-of-life offshore platforms is possibly the most unglamorous part of the oil and gas life-cycle. Understandably, operators do not welcome incurring the costs this work brings, but they do recognize the importance of disposing of their obsolete assets efficiently and with minimal environmental impact.

In some parts of the world, notably the Gulf of Mexico, local legislation allows for platforms to be cleaned and then sunk to create artificial reefs. Arguably, this is a sound environmental option, as new reefs become home to wildlife and the energy required for the disposal process is minimized.

However, in the North Sea, the Convention for the Protection of the Marine Environment of the Northeast Atlantic (OSPAR) requires that end-of-life installations are removed and disposed of.

One problem with removing these structures is that the equipment used in the industry, and the guidelines used for their use, has not really moved on in the 20-30 years since the platforms were installed. Techniques such as breaking the platform down into its original modules (employing a reverse installation process) or simply breaking-up the platform into small pieces, are the two methods most commonly used. These processes can be both inefficient and costly. In the recent past, some more innovative techniques have been tried—such as attaching buoyancy tank assemblies to the legs of a jacket, then de-ballasting and floating the jacket away. But these new techniques are the exception rather than the norm.

Single lifting

Another solution is the "single lift method," much like a reversal of integrated platform installation. There have been many projects set-up to develop a single lift solution (MPU, Seametric, Excalibur) however, none have made it to operation, so far.

One "single lift" solution that has progressed, and offers a much anticipated step-change in the decommissioning process, is the impending delivery of the Allseas heavy lift vessel *Pieter Schelte.* This new class of vessel has the potential to reduce the lengthy offshore preparation process required by current removal techniques. *Pieter Schelte* will have a topsides lift capacity of 48,000-ton and a jacket lift capacity of 25,000-ton. Its design enables it to straddle a platform and take off the entire topside in a single lift. This will significantly reduce the amount of offshore vessel time required to dismantle a platform, although the time spent in shore-side preparation is likely to be similar. The vessel will also be used for deep-sea pipe-laying as well as installation activities and it is understood that a larger sister vessel could be delivered in 2020.

Challenges remain

Although specialist vessels like *Pieter Schelte* may change the face of offshore decommissioning removal operations, it will not solve a number of the associated risks and challenges that this activity continues to face. Once removed, the structures—either whole or in pieces—are moved to a shore-side facility for recycling. Independent operators invest large sums to ensure their facilities are safe and kind to the environment and clearly need to realize a commercial return as compensation. These reception facilities must be prepared and able to receive the removed items as delivered, which may add further cost to the project as a whole. With oil companies tending to delay the removal of their platforms, competition amongst recycling yards is fierce and some are beginning to struggle.

Rightly, platforms must be cleaned and all hazardous material removed or contained before the structure is moved. Often they are left unmanned for some considerable time before they are eventually taken away. A period of non-maintenance and the introduction of an external and unfamiliar cleaning team is not the optimum combination to ensure an efficient and safe operation—particularly if the associated documentation is incomplete or not up-to-date. Having to deal with structures and materials in common use 30 years ago also creates problems. Paint used in those days, for example, is much more toxic than today's coatings and so must be dealt with in a way that does not harm the environment or the workforce.

Although unglamorous, decommissioning is an essential element of the offshore oil and gas industry but one that is clearly thought of as the poor-relation. Although the introduction of specialist vessels has the potential to change the face of the decommissioning sector, it will not solve all the issues that this activity continues to face. OE

***Alan Clifton** is a senior construction engineer and serves as the operations director for LOC in Norway. Clifton has acquired over 35 years' experience in the offshore construction industry.*

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Combating fatigue

Michael Long Ge and Himanshu Maheshwari explain a new methodology developed by BP and 2H Offshore to monitor fatigue on drilling riser systems.

In support of its commitment to safe and reliable operations, BP has been continuously developing a program to assess and maintain structural integrity for offshore drilling risers and conductors. In conjunction with 2H Offshore's riser experts, BP developed a new fatigue monitoring methodology for drilling riser systems due to both wave and vortex-induced-vibration (VIV) damage.

BP has been monitoring structural response, including the fatigue damage, of riser systems in the Gulf of Mexico over the past 10 years. The structural response of multiple BP drilling risers and conductors are monitored using a number of acceleration data loggers and/or strain gauges.

A drilling riser is subjected to fatigue due to VIV, direct wave loading and vessel motions. To date, the focus for riser systems has predominantly been on determining fatigue damage due to VIV, since it and its effects on structural response are generally not a well-understood phenomenon. The measured fatigue damage due to VIV is typically calculated by mode shape reconstruction in the frequency domain, using the logged accelerations at various riser locations.

In addition to VIV fatigue, direct wave loading and vessel motions also contribute to the total fatigue damage. Sometimes wave fatigue may have more contributions than VIV fatigue damage, especially in shallow water depths and/or wave dominant conditions, such as hurricanes or winter storms. Figure 1 shows the relation between median RMS accelerations from the loggers along the riser and significant wave heights for a period while the riser is connected. It indicates a strong correlation of the measured median acceleration to wave. In this example, the maximum acceleration occurs on October 2nd, when the highest wave is also observed. The contribution of wave induced fatigue to the total fatigue damage is material and should be considered. To confirm the long-term fatigue integrity, it is necessary to determine fatigue due to both wave and VIV effects.

To take full advantage of the accumulated data for the monitoring program, a new fatigue monitoring methodology was developed. The methodology is using an analytical solution which accounts for damage due to both wave and VIV effects. With the new method, the measured acceleration data is converted into curvature, and then fatigue damage along the length of riser and conductor is calculated. This new methodology has been validated with both finite element analysis (FEA) and field data, and sensitivities to various parameters have been considered.

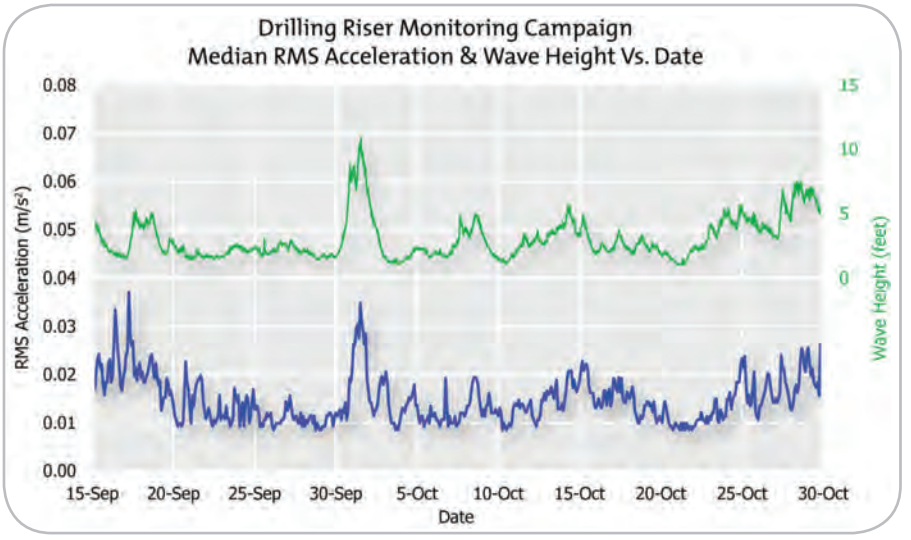

Fig. 1: Illustration of riser acceleration vs. wave height. Images from 2H Offshore.

Analysis methodology

Riser acceleration is measured at a number of locations along the drilling riser system using motion data loggers. An analytical transfer function is derived to correlate the accelerations with the curvature of riser at the data logger locations. Assuming an acceleration data logger is installed at point B on a riser segment OA, as illustrated in Figure 2, the lateral acceleration a(x,t) is converted to the curvature using wave theory.

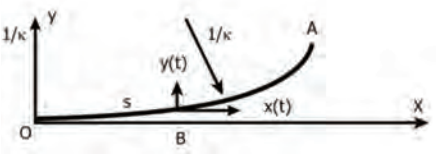

Fig. 2: Illustration of riser acceleration and curvature

The transfer function is shown in Figure 3 along with the spectrum of the acceleration. The transfer function decreases with increased frequency, but remains relatively stable within the wave frequency range. Once the curvature time traces are known, stress time traces at the outer fiber of the riser pipe can be calculated based on riser dimensions and material properties.

New methodology is validated based on the finite element analysis (FEA) and field monitoring data.

FEA is performed with specified input parameters, including environment data, riser configuration, mud weight, and tension. The outputs from FEA, especially the curvature along the riser string, are compared with results by the new

methodology. The advantage of using FEA results to validate the methodology is that there is no noise and g-contamination in the accelerations and curvature time traces. There are also no uncertainties in the added mass and tension values. In addition, the validation can be carried out along the entire riser length instead of the logger locations.

An example deepwater riser configuration is used for FEA validation. A sea state with a significant wave height (Hs) of 6.56ft and a peak period (Tp) of 7.6 seconds is selected, since this sea state causes the largest fatigue damage on riser compared with other sea states from the metocean data. An added mass coefficient of 1.0 is considered for both the FEA and analytical transfer methodology (ATM).

A time trace of the curvature obtained from the analytical transfer method is compared with that obtained from FEA output, as shown in Figure 4. The curvature from the analytical transfer method matches well with FEA results for both the phase response and the curvature amplitudes.

The standard deviations are also compared along the riser length in Figure 5. The standard deviations of the curvature from FEA and the analytical transfer method agree along the riser length except the top 60ft zone that is close to the tension ring where the joint dimension is modeled slightly different in both methods. The top slick joints below the outer barrel consist of three pup joints: 40ft, 20ft and 5ft. The top element in Figure 5 is right below the outer barrel. The outer barrel OD is 25in, while the top pup joint has a drag OD of 23.4in. The drag OD the pup joints are chosen according to given dry and wet weight. The ATM method considers the properties at the interface of two different joints, which cause the results to be slightly different from the FEA method.

Field monitoring data validation

The validation of the methodology is also conducted using field measurement data. A set of by 12 motion loggers and two strain sensors are deployed at specific locations along the riser string. The measured accelerations are used as input to calculate curvature data by the analytical transfer methodology, which are then compared with the ones obtained from the strain gauge sensor at the same location.

The field-deployed riser configuration with staggered slick and buoyant joints, is shown in Figure 6. During the operation period, the drilling water depth is 6823ft with a top tension of 1685kips and a mud weight of 10.8ppg. The accelerometer and the strain gauge sensor are located on the bottom end of the 6th joint above lower flex-joint, about 5ft above the joint interface, as shown in Figure 7. The structural OD at the sensor location is 21in, while the inertia OD of 41in considers the presence of riser fins and auxiliary lines.

A three day wave dominant response period is selected for field data validation. Figure 8 shows the comparison of the curvature between the analytical transfer method and the strain gauge measurement. The stress derived from the strain gauge sensor is used to obtain the field curvature. The curvature time traces from the two sources match well, as zoomed between 200 and 600 seconds. The low frequency contents below

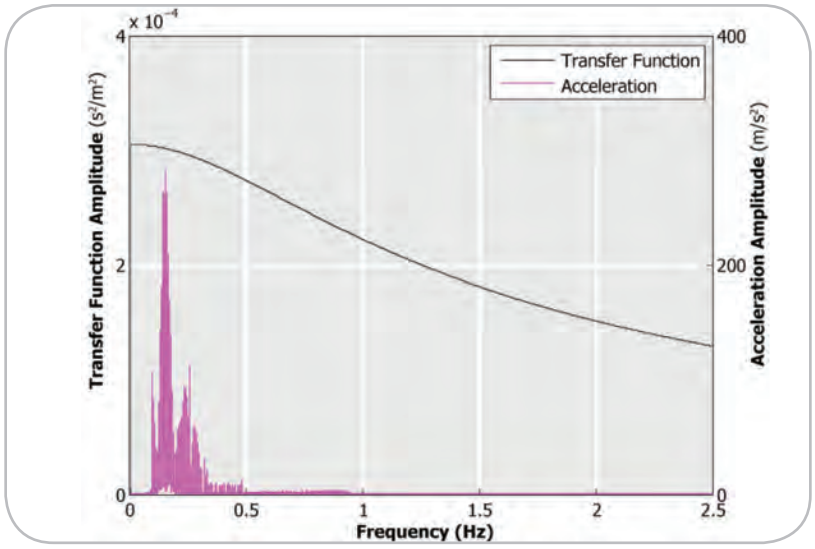

Fig.3: Transfer Function

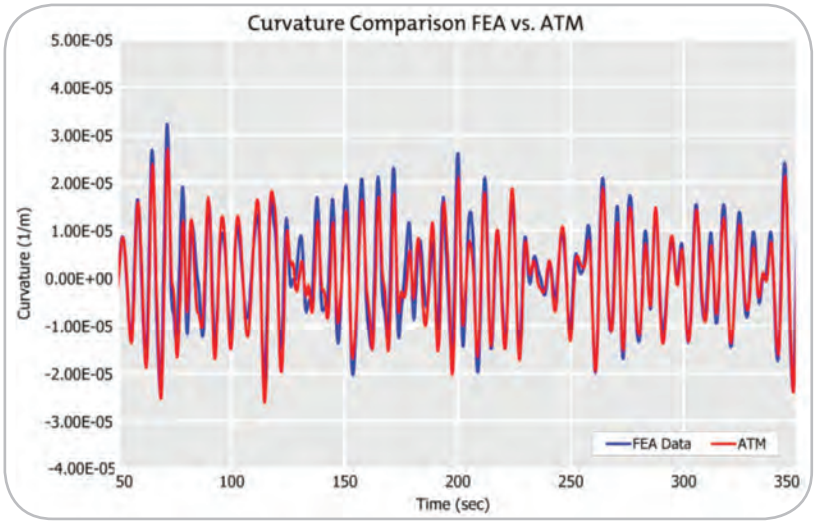

Fig. 4: curvature comparison between FLEXCOM and analytical transfer method

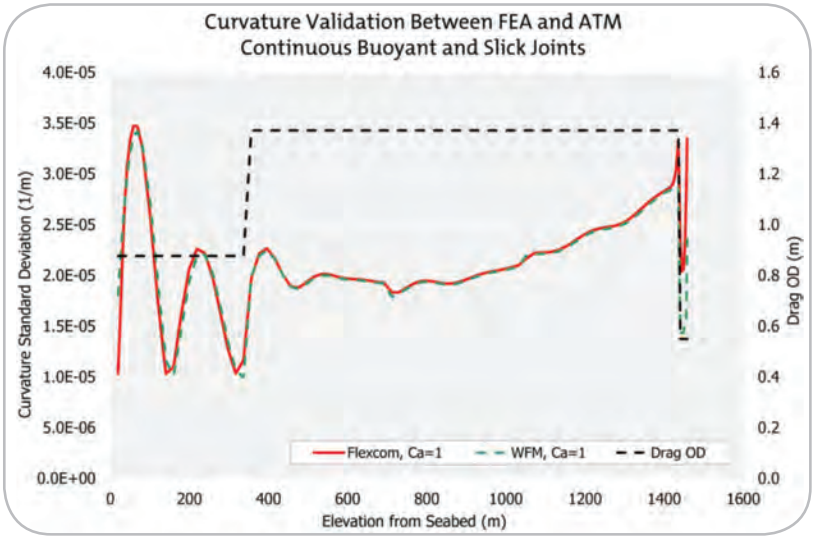

Fig. 5: Variation of curvature standard deviation along riser length

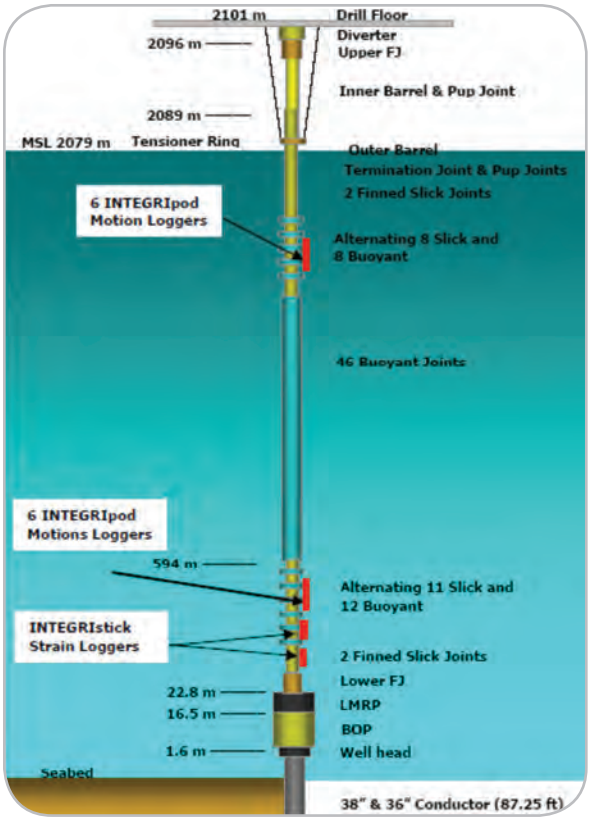

Figure 6: Riser Configuration for Staggered Joints

Figure 7: INTEGRIstick curvature sensor mounted on slick riser joint with fins

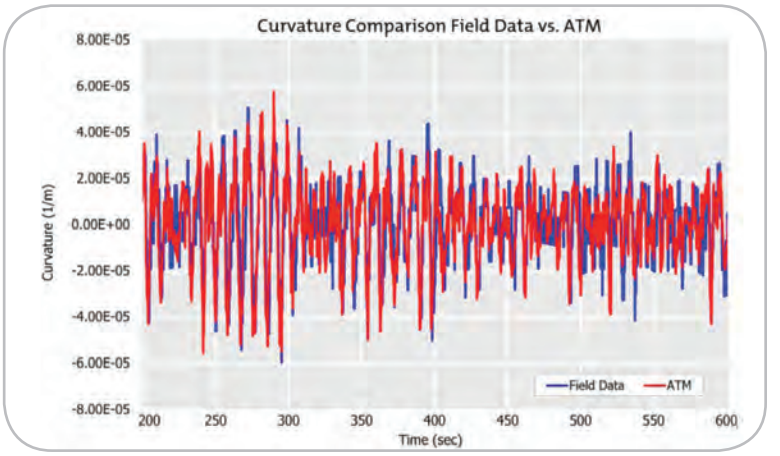

Figure 8: Curvature Comparison between Analytical Transfer Method and Field Data In Time Serial

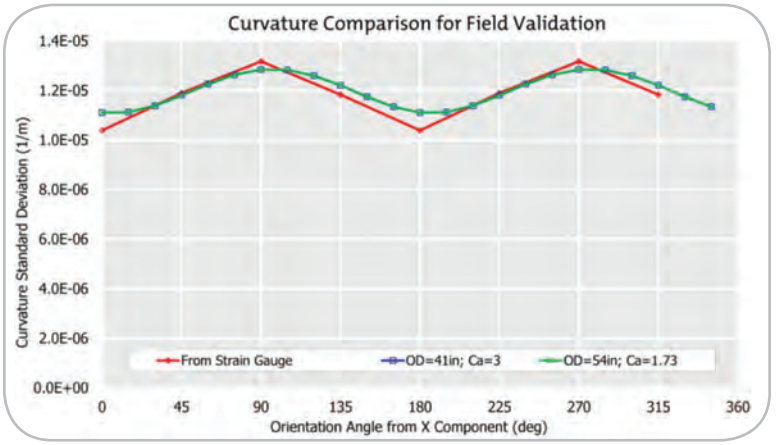

Figure 9: Curvature Comparison between Analytical Transfer Method and Field Data On Cross Section

0.05Hz in the curvatures are filtered.

The strain gauge sensor is located approximately 5ft above the joint interface, and the joint below this slick joint is buoyancy joint. Field added mass and equivalent OD are not clearly known, especially at the location of the strain gauge sensor which is located 5ft above the transition between the buoyancy joint and the slick joint with fins. At this location the hydrodynamic effects of buoyancy and slick joints coexist. Therefore, it is challenging to define the correct hydrodynamic properties for this formulation at this elevation. The standard deviation of the curvature around the pipe circumference is compared between the analytical transfer methodology and that from the field strain gauge. As shown in Figure 9, the analytical transfer methodology matches the field data well, considering a drag diameter of 54in and an added mass coefficient of 1.73 for the slick joint.

Sensitivity and discussion

The curvature using field data is affected by signal noise, sensor orientation, local tension at the strain gauge sensor, the added mass, and the alternation of the buoyancy and bare joints. The added mass and associated hydrodynamic diameter are not known, therefore the sensitivity of the curvature from the ATM to these parameters is studied in this section.

The sensitivity of the curvature standard deviation to added mass coefficient in the analytical transfer method is shown in Figure 10. The added mass coefficient is given as 1.0 for all riser joints in FEA, while it is varied between 0.5 and 2.0 in the analytical transfer method. The variation of standard deviations at six typical locations of the riser (A through F) is plotted against the added mass coefficient, as shown in Figure 10. Compared with the base case with Ca=1.0, the curvature standard deviation of the slick joints (A, B, C, D) increases about 3.6% for every increment of 0.1 (or 10%) in added mass coefficient, while increases about 4.8% for buoyant joints (E and F).

Measured riser tension and mud weight in the field may not always be

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100% accurate. Hence, the curvature standard deviations are also compared for different top tensions. The top tension of about 1800kips is increased and decreased 50kips and the corresponding curvature change is shown in Figure 11. For a constant tension change along the riser length, the curvature standard deviation shifts by a constant. Every 1% of tension change in the riser leads to about 1% of change in curvature standard deviation.

Field measured accelerations contain the portion due to gravity (g-contamination), and it may affect the curvature accuracy if not well understood. By retrieving the riser tilt angle at any given location from the FEA model, the acceleration of gravity, g, can be projected into the accelerations as controlled g-contamination, which is compared with the accelerations

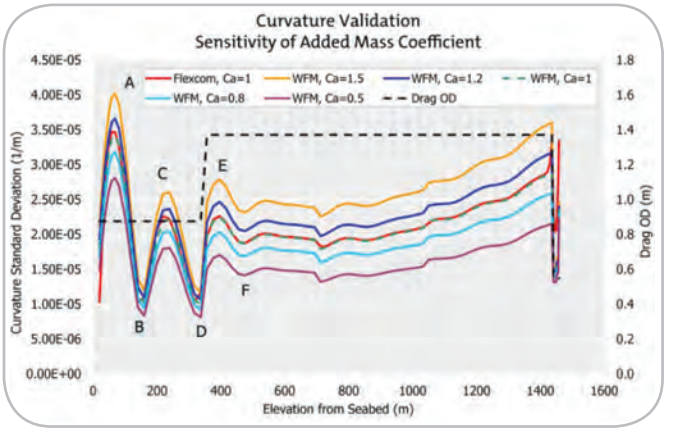

Figure 10: Sensitivity of Curvature Standard Deviation to Added Mass Coefficient

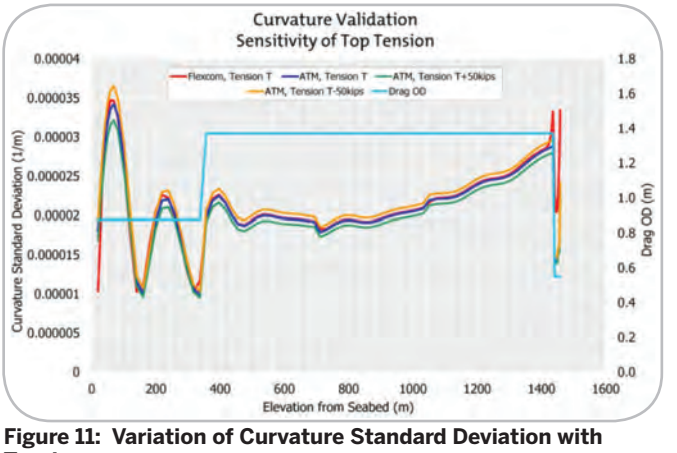

Figure 11: Variation of Curvature Standard Deviation with Tension

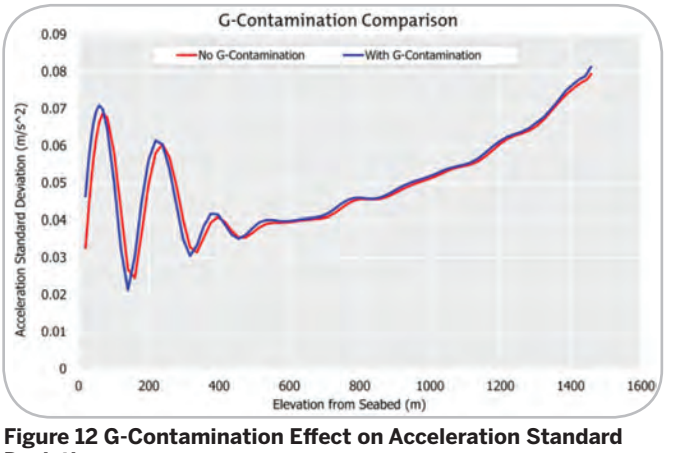

Figure 12 G-Contamination Effect on Acceleration Standard Deviation

from FEA output to analyze the percentage and sensitivity. In time domain, accelerations with and without g-contamination are compared and shown in Figure 12. A maximum g-contamination of 14% of the acceleration standard deviation is found along the riser length. The g-contamination is found negligible. Note however that for applications where higher dynamic riser angles are expected, the g-contamination can be removed through the use of angular rate measurements.

Conclusions

To take full advantage of the accumulated monitoring data, a new fatigue monitoring methodology was developed using analytical acceleration to curvature transfer function to account for the fatigue damage due to both wave and VIV effects.

This new methodology has been validated very well with a finite element analysis (FEA) method, by comparing curvature distribution. The advantage of using FEA results to validate the methodology is that there is no noise, g-contamination, and added mass and tension uncertainty in the accelerations and curvature time traces.

Comparing with field measured data, the results show that the calculated fatigue is sensitive to added mass and drag diameter, but not g-contamination. With a 54in-diameter drag and an added mass of 1.8, the proposed method matches well with the measured field data. A standardized approach for selecting the added mass coefficient and hydrodynamic diameter is the subject of ongoing work.

For future work, both acceleration and strain measurements from a riser system with continuous buoyancy or slick joints are preferred to better understand the effect of the total added mass, which is dependent on the added mass coefficient, Ca and the drag diameter. In addition, a more detailed and complicated CFD simulation may be conducted to investigate the actual drag affect and added mass effect. Extra strain sensors on different locations and a non-staggered riser configuration would also assist in further validation of this methodology. OE

Acknowledgments

The authors thank the management of BP for permission to publish this paper. In addition, the authors wish to express thanks to 2H Offshore engineers who did the data analyses documented in this paper.

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Preventing damaging vibrations for long term pipeline protection

Specifying the right vortex induced vibration suppression solution is vital to ensuring pipeline longevity. Jonathan Fox explains.

The offshore oil and gas environment has experienced times of change and development. About 30% of the world's oil production comes from offshore areas* and with more exploration and production activity taking place in remote locations with deeper waters and harsher climates, subsea challenges are increasing. Although production platforms historically resided at distances of 6mi from shore in 1970, projects are now more often based a significant 200mi from shore and in deeper waters.

These developments mean deepwater flowlines are faced with greater pressures and temperatures, all while demands for longer lasting products continue to grow. With this in mind, subsea solutions are required to perform more efficiently and robustly to ensure that performance is guaranteed for the lifetime of the project.

A remaining challenge is the impact and severity of vortex induced vibration (VIV) on deepwater pipeline applications. This includes steel catenary risers and rigid steel flowlines, which are unsupported over free spans.

The issues with VIV

In offshore conditions, VIV fatigue on a cylindrical structure is caused by the regular shedding of vortices from the pipe when subjected to a steady current.

As a fluid flows around a cylinder, separation of the wake cycles from one side to the other, coalescing along the length. This leads to an alternating transverse force whose frequency is dependent upon the fluid flow.

At certain water flow rates, the frequency of the vortex shedding can match the natural frequency of the pipe length, causing it to vibrate. This reaction can become more or less severe, depending on the current and also the pipe's position in the water; as currents are more prominent closer to the surface of the sea.

It is this reaction of vibration or, more specifically, vortex induced vibration, which causes accelerated fatigue damage to the structure and gives rise to problems such as pipe girth weld failure, premature pipe failure or end connection malfunction. By suppressing VIV, fatigue failure of the pipe's structure can be reduced or even eliminated.

VIV suppression

A high-performance VIV suppression system will primarily restrain the damaging vibrations to an acceptable level, while providing impact and abrasion protection benefits. Specifically, a solution which has been designed to stop the formation of vortices will efficiently prevent the detrimental VIV behavior.

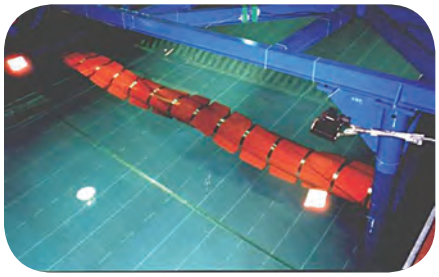
The right VIV suppression solution should incorporate overlapping and interlining moldings which wrap around the pipe and include three-start helical strakes. This will provide the triangular / trapezoidal strake profile required to prevent the formation of vortices and thus eliminate VIV. It is important that

The J-Lay test rig applies a 20 te vertical load via the rollers whilst pulling the product through
Image from Trelleborg Offshore.

the product is designed to be independent of direction, as the flow can pass by the pipe on any route or path.

Traditionally manufactured using reaction injection molded polyurethane, each section of the VIV suppression product would be molded and then allowed to cure for hours. However, more recent practices have seen the product manufactured through thermoforming, using thermoplastic materials. This process is much simpler than the traditional techniques and is six times faster, resulting in reduced lead times, as well as project cost and time savings. Thermoplastic materials also exhibit the additional benefit of being recyclable.

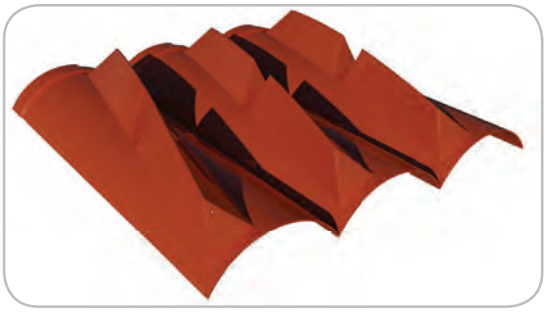
Similarly, with the ability to produce a thinner product under the latest manufacturing practices, less material is required to produce the same high performance product. This not only makes the solution more sustainable but also lightweight, ensuring that it is easier to handle and pre-install onshore, or install offshore. The debilitating effect of drag on the structure is also reduced due to the smaller effective hydrodynamic diameter.



A hydrodynamic tow tank test of the strakes on a pipe.

Stinger load test equipment.

Images from Trelleborg Offshore.



Lightweight, stakable VIV suppression strake.

Images from Trelleborg Offshore.

Overlapping and interlocking moldings, with three-start helical strakes.

The product design should also enable each single component to be stacked efficiently. This, in turn, can drastically reduce the amount of required storage space so that transportation and containerization is much more efficient and cost effective.

Once an installation vessel has reached the field, the single component pieces are lifted from the deck, ready to install into place. Traditionally, the industry would install the pipelines via the S-lay method, where the pipe is installed over a steel structure hanging off the vessel. This meant that the total weight of the pipeline would be hanging off the structure, and during installation, the strake would have to withstand the full weight of the pipe.

However, as the industry has developed to move away from this type of installation method, pipes are now often installed using a J-lay method. This allows the pipes to be installed vertically in individual sections. Each piece is welded to the next and then lowered down into the sea, which reduces the loads experienced by the strakes. The J-lay load can still be fairly significant, so it is important that the strake solution is load bearing. Up to 20tonnes is ideal.

Testing

As a critical solution in an increasingly more challenging environment, it is vital to fully test the VIV suppression system.

Consultations with industry-renowned hydrodynamicists, alongside computational fluid dynamics analysis will enable the calculation of fluid forces, helping to determine the impact of a liquid or gas on product performance. This analysis should be available for any VIV suppression system as well as the results of physical hydrodynamic testing.

On a project-by-project basis, a VIV suppression manufacturer should provide sufficient impact, axial slip and load bearing capacity testing results. Specifically, an efficient J-lay test should be capable of applying a 20tonne vertical load along the length of the suppression system via a roller which simulates a small stinger or J-lay pipe installation.

All materials and geometries should be fully-qualified for long-term subsea use.

Conclusion

The unpredictable nature of an offshore environment means that the industry must remain flexible and responsive. Vortex induced vibration will always naturally occur where water flow meets a cylindrical pipe under the sea; however, the severity of this reaction will change as surroundings become harsher. The specification of the right VIV suppression solution is vital to ensuring that pipes can be protected for the project's lifetime.

A product which not only does the job it is specified to do, but also offers benefits such as ease of use, more cost effective transportation and faster manufacture, will bring greater advantages to the project.

The exploration of oil and gas comes with its challenges and if contractors don't sufficiently plan for these, they could fall victim to colossal financial implications and time delays. The assurance that comes with a high performance product is invaluable and is vital to providing that all important peace of mind, now and in the future. OE

*From Infield System's Global Offshore Oil and Gas Outlook, Gas/Electric Partnership, 2013.

Jonathan Fox is a senior product development engineer at Trelleborg Offshore. Fox has seven years' experience at Trelleborg, working in polymer engineering design and specializing in the design of offshore products, such as vortex induced vibration (VIV) systems, buoyancy, clamping solutions, and bend protection. Jonathan, a chartered engineer, holds a BEng (Hons) in Mechanical Engineering and is based in Skelmersdale, England, UK.

Testing under tension

Using the tensioner test rig simulator can show how to improve tensioner pad design, says MacKinnon Marine's Alex MacKinnon.

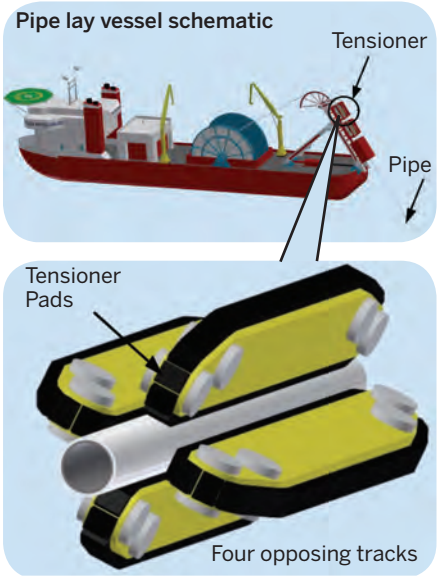
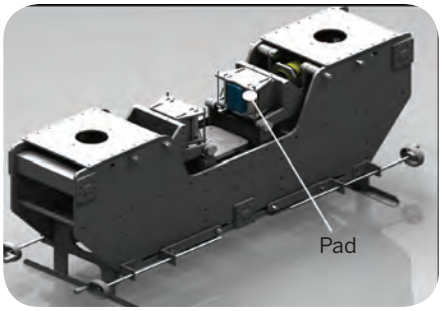


Fig. 1: a typical pipe lay tensioner.
Images from MacKinnon Marine.



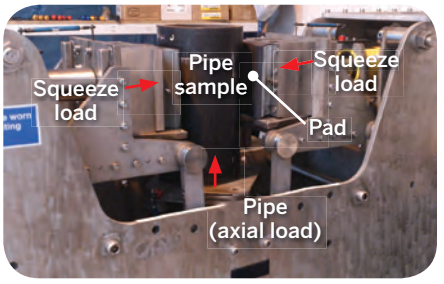


Fig. 2: full size two track tensioner simulator.

The technical demands on pipeline installers continue to grow, due to the need to service the deeper field depths being exploited. Equipment providers are responding, with the result that everything is getting bigger and heavier.

Unfortunately, in many cases this comes at the price of poorer operability, and tensioners are no exception. Tensioners are used to transfer rigid flowlines and risers to sea, while maintaining full control of the product catenary top tension. For tensioners, bigger can't always be practically achieved, so bigger often means doubling up, and a number of pipelay systems are now operating with two large tensioners on the reel lay tower, giving up to 800-tonne dynamic capacity.

Double unfortunately means taller, and taller usually means wider, for stability. Wider leads to longer, for efficient hull shape for transiting, leading to increased costs. One potential driver to capex cost reduction is to look more closely at the tensioner pad itself.

The tensioner pad is at the heart of the tensioner. It is a small piece of rubber/steel, which is pivotal to assuring safe and efficient operations. At this critical and highly complex frictional interface between the installation machine and the product, it would be good to know what is actually going on. In deeper fields, knowledge in this area moves from being good to know to being essential to fully understand. This is a specialized area MacKinnon Marine has research and development experience in, as well as a test facility.

The best way is to trial a system is to replicate the offshore installation conditions in a simulation test facility, using the same full-size tensioner pads you are going to use and the actual product pipe that is going to be installed. The key measurements are the compression behavior of the rubber pad and, more importantly, the frictional performance under a range of loading.

Real-time monitoring of displacements, pressures, and loads provides useful information for extrapolation to the full tensioner size. An ability to see tensioner pad deformation behavior leads to a robust understanding of how the system will perform. Fast data acquisition is

Fig. 3: Tensioner test simulator display

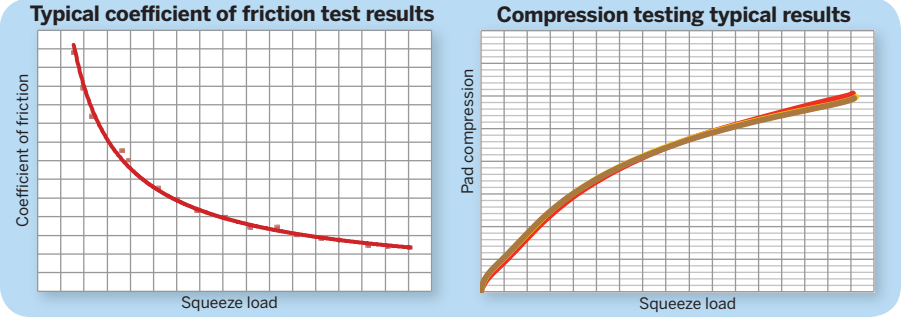


Fig. 4: The effect of load on rubber coefficient of friction and pad compression

used to investigate the rate of change of slip and exhaustive test variables, such as pad size and material, pipe diameter and coating type, temperature, water presence, contamination, etc., provide a sound understanding of the frictional behavior and compression response.

The declining friction coefficient with increasing track loading indicates that efficient pad design is required to provide useful levels of friction at the high loads necessary to have relatively short tensioner lengths in deep water. This is particularly true when temperature variation and the presence of contamination, typical in spoolbase facilities, becomes present on the pipe coating, resulting in significant friction reduction. In many cases the design friction coefficient is not achieved at high load, so an 800-tonne system may no longer hold 800-tonne.

Field joint coatings, typically 12.2m apart, also need to pass through the tensioner. The radial upstand height overloads the limited suspension available within the tensioner, causing a severe limitation on allowable track loading and, consequently, the top tension that can be held.

It is sobering to learn that the friction

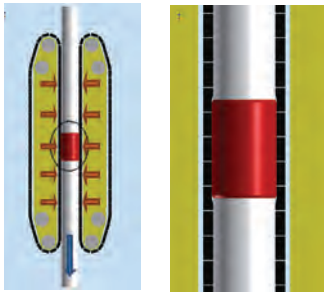


Fig. 5: Field joint passage through the tensioner

level envisaged does not exist and to realize that even small changes in a couple of parameters can significantly reduce the operational margin that is available.

In a recent test, simulating a four track tensioner with 400-tonne capacity holding a 12in. diameter pipe, two designs of tensioner pad were tested back to back. The MacKinnon Marine design returned significantly higher friction coefficient (circa 80%) right across the range of track loading indicating that by simply changing the tensioner pads an immediate performance upgrade is generated. For an existing tensioner, that means more operational margin up your sleeve and for a new build vessel the chance to fit a shorter tensioner.

Using the tensioner test rig simulator can show how to improve tensioner pad design, offering more friction coefficient over a wide range of track loading, even when challenging field joints are present. It also allows a challenge to the tensioner design friction coefficients currently considered. If additional friction is present, through good tensioner pad design, the tensioner can be designed to be shorter for the same top tension capacity, an effect which cascades through the whole lay spread and vessel sizing. OE

Alex MacKinnon *is MacKinnon Marine's managing director. He has more than 20 years engineering experience and has been involved in all aspects of subsea engineering, including detailed design, subsea construction, and pipelay, globally. He specialises in installation engineering and tensioner pad design and testing. MacKinnon has a PhD in Experimental Aircraft Aerodynamics from Cranfield University. He also has a BSc in mechanical engineering from Dundee College of Technology.*

Exploring the underexplored

A new impetus to explore the UK North Sea could help to unlock some of the basins' underexplored plays. Elaine Maslin found out more.

A significant anniversary in the UK Continental Shelf's (UKCS) exploration history passed by quietly this May.

It was the 1964 enactment of the Continental Shelf Act. Its ratification by the UK Government opened up the North Sea to national and international exploration companies.

Fifty years later, there are more companies in the basin than ever and interest in the latest licensing round (28th) was high, with 173 applications for around 370 blocks or part blocks. But exploration activity has fallen and discoveries are on average less than 20MMboe.

In a bid to boost exploration rates, the Exploration Task Force (ETF) was set up in 2012 by industry group Pilot to promote the basin's new and underexplored areas and improve exploration well performance.

In addition to the ETF's work, the Department of Energy and Climate Change (DECC), the Natural Environment Research Council (NERC), and industry body Oil & Gas UK also sponsored a cross-industry scoping study by SLR Consulting. The study's aim was to assess how to produce an online, 21st century exploration road map to the UKCS to aid in providing a better understanding of its resources.

The impetus to improve exploration performance is strong—if new discoveries are not made soon, current infrastructure will be removed, limiting the economic chances of future discoveries, Oil & Gas UK and Petroleum Exploration Society for Great Britain president Oonagh Werngren warned.

"We have been exploring here for 50 years, but there are vast differences in understanding between the different basins," says Oonagh Werngren, who

The Cygnus Alpha wellhead platform during installation offshore. Photo from GDF Suez E&P.

is also operations director at Oil & Gas UK and is responsible for running five different PILOT workstreams dedicated to maximizing recovery from the UKCS, including the ETF.

"Although the central North Sea has been developed, there are still significant resources to be developed, including high-pressure, high-temperature (HPHT), and the western margin of the platform. That area offers the greatest potential for the next tranche of developments, because there is a lot of ullage available in the existing infrastructure and a lot of interest in drilling in that area.

"West of Shetland is the least mature area, with limited existing infrastructure, but with a lot of prospectivity for the future. The Hebrides and Forth Approaches basins are both under explored.

"The northern North Sea and southern North Sea are two of the oldest basins and were explored very quickly and major fields put online. The upside might be more limited, but that isn't to say there are not plays to be developed going deeper."

Some areas are already opening, such as the Carboniferous. It has lower calorific-value gas than the already produced Permian gas, and earlier drill stem tests on it did not flow. "Now we have a better understanding of the geology, the zones that have permeability, and where it offers the greatest production," Werngren says. As a result, a whole new play in the northern margin of the southern North Sea has been opened up.

GDF SUEZ E&P UK has explored the Southern basin Carboniferous with success and is now developing Cygnus, a significant four-platform development, as a result. "Our view is that the Carboniferous has got a lot more to give," says GDF SUEZ E&P UK's subsurface manager Andy Spencer. Typically, reservoirs have been exploited at 8-11,000ft in the Southern Gas basin. GDF SUEZ is now looking at the potential for going deeper.

The Alpha wellhead platform in place in the Cygnus field. Photo from GDF Suez E&P.

Oonagh Werngren, Petroleum Exploration Society for Great Britain president and operations director at industry body Oil & Gas UK. Photo from Oil & Gas UK.

The reasons why some of these areas have not been fully explored vary. For the northern part of the gas basin, it was the lower calorific-value gas, challenging reservoir quality and higher costs associated with drilling hazards in the Zechstein salt. Spencer says improved seismic imaging from modern 3D surveys will play a key role in identifying new opportunities which were not seen on the existing 20 year old datasets.

In the fractured basement, the issue is about technology, around well completions, and also the depth of such reservoirs, Werngren says. "The basement rock itself has very low permeability, so it is also around our understanding of the additional permeability you can get through fractures. In some areas, it is about the hardness of the rock and our ability to see through it, such as

New/underexplored plays

on the UK Continental Shelf, outlined by Oil & Gas UK

West of Hebrides

Within the west of Hebrides area there are a number of known geologic provinces that include the North and South Rockall basins, Hatton basin, Rockall Plateau and the Hatton Continental Margin.

The Rockall basin is a major component of the rift system, which formed as a precursor to the present Atlantic Ocean. To date there is no conclusive proof of a pre-Cretaceous extensional phase within the Rockall Trough, which would provide the source rock which is required for a working petroleum system to be in place. A viable but rather local petroleum system has been proved for the Rockall basin: in the UK sector, the Benbecula well tested positive for gas while in the Irish sector, tests of the Dooish well established the presence of gas condensate. However, there are vast areas with no wells and very sparse, low quality 2D seismic coverage that remain unexplored.

One of the main challenges is to establish whether there is a viable petroleum system for other frontier areas including the Hatton basin and Hatton Continental Margin farther to the west. Initial limited exploration of these basins has led to the identification of potentially attractive tilted fault-block plays. The presence and maturity of significant source rocks remain to be proved.

Carboniferous beneath Central North Sea, East Irish Sea and Southern North Sea

Carboniferous reservoirs are usually laid down in deltaic (river delta) or fluvial (river) environments, formed from the precipitation of calcium carbonate. To date, most Carboniferous traps rely on a closure, either dip or fault bounded, at Top Carboniferous but there is potential for exploration of deeper traps.

The Carboniferous in the Southern North

The *Polarcus Naila*, which started a 3D multi-client survey West of Shetland in June. The survey will be the industry's first 3D data over the Brendan basin, in Quad 219, and will cover 2500sq km, says TGS. Photo from Polarcus.

sub-basalt. A lot of effort has been put in to understanding that."

There is limited interest in the Triassic sandstone in the English Sherwood Channel, south Celtic Sea and St George's Channel. This is possibly due to the challenges regarding access to the resources, in what is a busy shipping lane. For the latter two plays, the distance to market is another factor to overcome. "Technically, in all the basins in the UK, there are interesting opportunities, but each area has its own challenge," Spencer says. "In the central North Sea there is a lot of potential for 50MMboe prospects, but there is labyrinthine infrastructure to deal with. You can make a discovery, but making money out of it is not easy."

Companies are already starting to work more closely together to ensure cluster developments can go ahead, instead of risking stranded fields.

A further initiative, suggested by the recent Wood Review report (OE: April 2014), could see government-backed seismic acquisition to help further understand of some of the underexplored areas.

Meanwhile, research is now under way on how to create the 21st century exploration road map. At a recent PILOT meeting there was industry support for DECC to move ahead with key projects to establish a new understanding of the risks in the basin and some key projects to unlock hydrocarbon play systems. The key will be collaboration from both operators and the supply chain – but we need to act fast. Rising costs are in danger of causing a premature end to exploration," Werngren says. OE

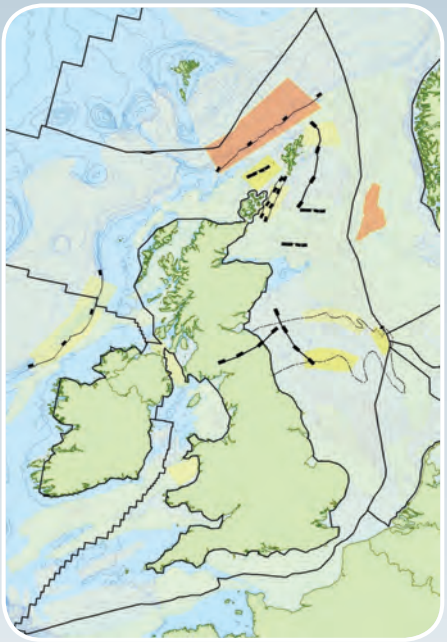
Sea provides the principal source-rock interval for the basin but also contains numerous potential sandstone reservoir intervals.

Through analysis of its biostratigraphic profile, marine shale within the Carboniferous can be correlated across large areas. It is possible that these "shaley" units could provide what are known as intra-Carboniferous seals. An example of where the intra-Carboniferous has been proven as a seal is the Boulton gas field (Block 44/21a) which is an anticlinal structure. Gas is trapped by a combination of up-dip seal against Permian shales and salts, and side seal from faults and low permeability Bolsovian sandstones.

Few of these intra-Carboniferous traps have been tested where they are not in combination with a closure at Top Carboniferous. This is an under-explored play type which requires more detailed seismic interpretation within the Carboniferous and further investigation into whether the rock presents the distinctive layers likely to provide potential sealing horizons.

Fractured Basements

Fractured basement rocks are hard, mostly granite formations. Post deposition tectonic events, including earthquakes, try to push and bend these formations, but due to their brittleness they crack, resulting in seismic-scale faults and highly connected fracture networks. Lateral migration from local reservoirs fills these extensive fracture networks with hydrocarbons, meaning that oil production is from the fractures not the rock matrix. This is dependent on the presence of an extensive, open fracture network.



Map of the UKCS with the proven and potential Fractured Basement Plays highlighted. Image from Oil & Gas UK.

Most basement hydrocarbon plays are hosted in structural highs (either fault blocks or buried hills) which commonly form tilted fault blocks, described as "half-grabens." Areas of the UKCS with proven and potential Fractured Basement Plays are: Rona Ridge Discovery (Clair, Lancaster, Whirlwind), Atlantic Margin (Rockall Ridge), Cairngorm Discovery, Bagpuss Discovery, Orcadian basins, Cardigan Bay, Mid North Sea High, Irish Sea (Rathlin Trough) and Utsira High (Norge).

New technologies, such as advances in seismic survey techniques used to predict fracture formations, will enhance the industry's capability to assess the potential of the basement as a hydrocarbon-yielding reservoir. Similarly, areas once considered uneconomical or technically challenging can now be explored, representing a new play concept for the UKCS.

Sub Basalt and Cretaceous sands, West of Shetland

Basalt is an igneous, fine grained rock which can be laterally extensive when extruded as a lava flow. The presence of these shallow, high velocity, highly heterogeneous (continuous) layers can scatter the seismic energy during seismic surveys providing challenges for interpreters of the data. This play concept centres on a deeper cretaceous sandstone reservoir which is difficult to map due to the presence of the basalt layer above, obscuring the seismic imaging

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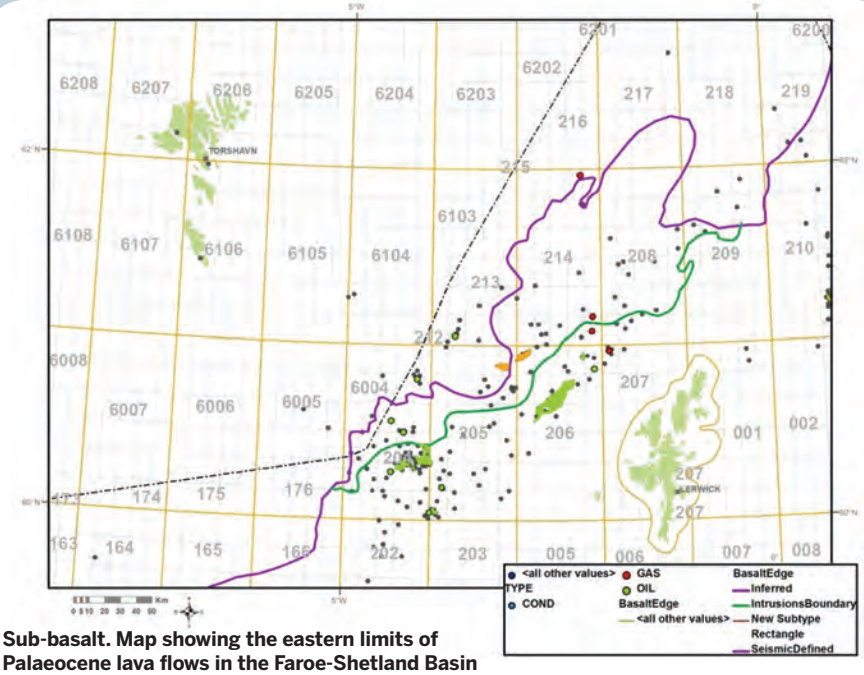
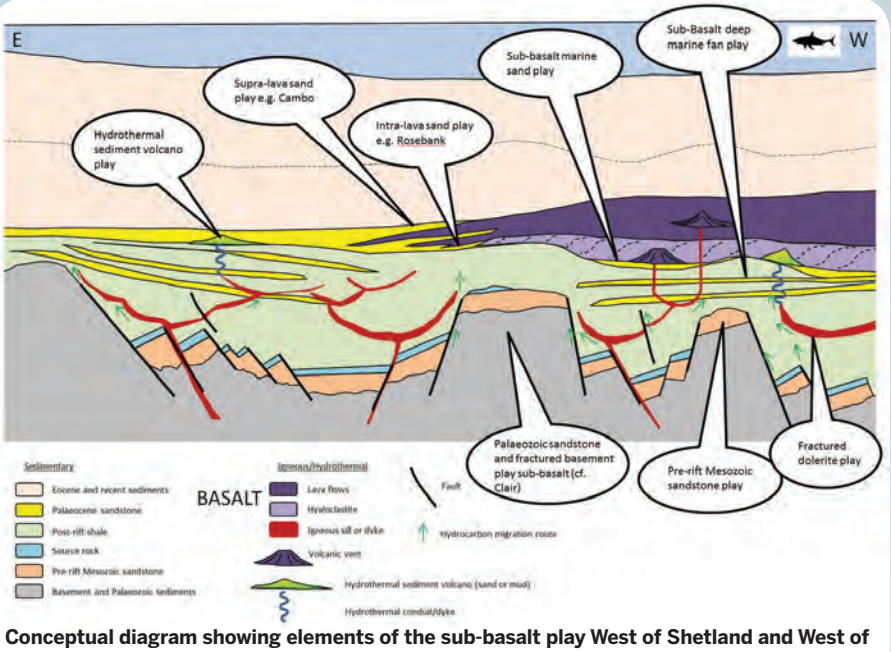


Sub-basalt. Map showing the eastern limits of Palaeocene lava flows in the Faroe-Shetland Basin (purple line) and the eastern limit of the main intrusive sill complex (green line). Sill complex outline modified from Rateau et al. (2013), well and field data from DECC. Image from OMV.



Conceptual diagram showing elements of the sub-basalt play West of Shetland and West of Britain, after Rateau et al. (2013), Grove (2013), and Helland-Hansen (2009). Image from OMV.

of the deeper reflectors.

Through the study of similar rock sequences observed in outcrops onshore, the properties of these sandstones have been shown to be of reservoir quality. Acquisition of additional seismic data and interpretation can better map these sub-basalt Cretaceous sands. The first sub-basalt discovery is the Rosebank field West of Shetland.

Southern North Sea High CO_2 Gas

The gas in the South Eastern part of the Permian basin in the UK is characterized by unusually high CO_2 (carbon dioxide) and N_2 (Nitrogen) contents, often referred to as "fizzy" accumulations. This area extends into the Dutch sector and includes several hundred bcf of undeveloped gas.

Although the gas in the Rotliegend reservoirs of the Southern Permian basin is predominantly methane, the area in the extreme south east of the UKCS waters has high inert contents. The 'Fizzy' accumulation (tested by well 50/26b-6) contains 50% CO_2 and 9% N_2. The nearby 54/1b-6 'Oak' discovery has similar high inert contents (36% CO_2 and 25% N_2). This region of high inert gas content extends into the Dutch sector (Blocks P1 and P2) and is a related to the inverted 'Fizzy Horst' structural feature (Yielding et al., 2011).

The key to unlocking this resource is the application of technology that will allow commercial development. This technology needs to address the removal and disposal of the inert content to provide a gas stream that meets market requirements or to allow the efficient combustion of low calorific value gas.

Triassic West of Shetland

Exploration and development of West of Shetland fields are predominantly focussed on Paleocene age reservoirs (such as Schiehallion, Foinaven and Clair). South of these discoveries, well penetrations have discovered Triassic age reservoirs which are older than Paleocene. Two depositional models are relevant for this play. The wetter climate depositional model consists of alluvial fans forming against basement highs during the active rifting phase of the formation of the Atlantic Ocean. The drier climate depositional model is similar but rather than fluvial channels there are aeolian (wind blown) sand dunes and sandflats, such as the Otter Bank formation. The Triassic play concept has been proven in Liverpool Bay, east Irish Sea as well as south of West of Shetland. This is considered a new play as it is under-drilled and little understood.

Permian in the East Irish Sea

The East Irish Sea basin is divided into several sub-basins and highs. The basins were formed by the Triassic rift development of grabens and half-grabens, a characteristic geological feature of the UKCS.

Sherwood Sandstone is a regionally developed system with good quality reservoir rock. This formation accounts for a large majority of the currently proven reserves. The main exploration risk in this area lies with source rock maturation and hydrocarbon migration, most likely in the deepest buried areas away from the location of uplift during the early Cretaceous period. Traps rely on hydrocarbon migration from younger Liassic reservoirs to older Triassic reservoir through fault juxtaposition. Evaporites (rocks formed by the evaporation of provide good sealing potential but halokinesis (the movement of salt or salt bodies) adds uncertainty to structural modelling and may also hinder hydrocarbon migration. ▪

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Subsea realities

Rising subsea development costs have led Statoil to set a target for 20-30% cost reduction on projects. Elaine Maslin reports from the Underwater Technology Conference.

The conference auditorium during UTC in Bergen. Photos from UTC.

"Subsea – facing new realities" was the slogan for this year's Underwater Technology Conference (UTC) in Norway.

The new realities discussed at the event, held in Bergen during mid-June, were often sobering. Rising costs are hurting the industry to the extent that Statoil has set a 20-30% capex reduction target. It also suggested using minimal facilities platforms with dry trees as an alternative to full subsea developments.

Anders Opedal, senior vice president project management and control, Statoil.

Manufacturers are tempering their focus on future technology breakthroughs, such as using HVDC for long distance step-outs, and subsea qualified variable speed drives, and focusing on how existing technology can, instead, be optimized.

The sober tones should not be a surprise. Operators have already been cutting back, and new technology has been one of the victims. Earlier this year, Shell and its partners on the Ormen Lange field announced they were shelving, at least for now, plans for subsea compression on the development, after years and millions spent on a pilot project. Shell cited costs and updated reservoir analysis.

Part-state owned Statoil is feeling the pain. Subsea production is a large part of the firm's business.

Statoil introduced its subsea factory concept in 2012, with an aim to have a complete subsea factory by 2020. It is looking to take subsea developments longer, deeper and colder, opening areas otherwise impossible to work in. The firm's Åsgard subsea compression project is a step towards this goal. System integration testing is underway by Aker Solutions and a pilot compressor is running at full speed underwater at Statoil's K-Lab.

"Subsea is increasingly important to Statoil. It is 50% of our equity production. We are the second largest subsea operator worldwide with more than 520 subsea wells and a significant yearly subsea spend," Anders Opedal, senior vice president project management and control, Statoil, told delegates in the opening session at Bergen's Underwater Technology Conference.

"But between 2003 and today, costs for subsea projects have in general doubled," he said. "Costs on subsea production systems have tripled over the last 10 years," he said, adding that market predictions suggest costs will continue increasing, at up to 5% a year. "We think this is not sustainable. We need to turn it around. With increasing costs, you would expect quality has increased. That is normal in other industries. I'm afraid to say, we have not seen this, at least not in full effect."

Opedal gave an example. He said on one subsea project, 70% of all engineering documentation received for review was sent back due to poor quality. Nearly 20% was sent back at least three times. "During the same project NOK700 million was spent rectifying quality defects in equipment. If you extend this across the portfolio we're paying millions for quality defects," he

Did you miss UTC? If you did, you missed their hi-tech opening video. But don't worry—you can see it by scanning this page with the Actable app.

said. "Cost inflation must be reversed and quality must be improved."

Statoil has been working to address costs, with a large focus on standardization—which has become a buzzword in the Norwegian sector, and has been high on the agenda at UTC for a number of years. One project, to create standardized umbilicals, comprising electrical and fiber optic cables, and hydraulic and chemical lines, is already bearing fruit.

Nexans recently delivered the first of four "Statoil Standard" umbilicals, ordered in 2012. The first umbilical will be used at the Oseberg Delta field in the Norwegian part of the North Sea, and the technical and administrative procedures developed on the Oseberg project will be used to save time, cost, and materials during its execution and on future projects, including the Snøhvit gas field (Barents Sea), and Smørbukk South (Norwegian Sea).

Statoil has also been working with suppliers to develop a new workover tool, which can work on any Xmas tree, saving millions of NOK, Opedal said. The firm is also working on a standard subsea catalog for subsea systems, which will be made available to all other operators on the Norwegian Continental Shelf, and it is working with organizations including Norske Oil and Gas and API to increase standardization. The firm is also looking at new standard contracts for delivering subsea production systems, from 2015, to bring down CAPEX and simplify technology specifications, on new fields and aftermarket. "We are working towards more universal interfaces, like the universal work-over systems and standardized umbilicals," Opedal said.

Nexans umbilicals systems.

Statoil has also been working on other areas, including improving transparency around technology integration, having longer term lead times, and portfolio planning to help suppliers. In February this year, Statoil launched a company-wide efficiency project, called Strategic Technology, Efficiency, Program, which is currently focusing on an earlier focus on selecting more cost efficient solutions and a larger degree of standardization.

Statoil is also looking at alternatives to full subsea developments. At its February capital markets day, Statoil discussed an unmanned, low-cost wellhead platform concept, described as "subsea on slim legs." It would be a low cost solution, with drilling from a jack up, or, where water depth prohibited using a jackup, a mobile drilling module, which could be lifted on to one of these unmanned platforms, could be used for drilling operations, before being moved to another lost-cost wellhead platform, Opedal said.

"We are assessing this and we have a real competition between subsea and this unmanned platform," he told UTC. "As these platforms are too small to be built in Asia, (due to transport costs) they offer a great opportunity for European subcontractors. And they could be repeatable designs. The main driver for savings is replacing wet Xmas trees with dry Xmas trees." OE

Wind power gains

More than 3.8GW of offshore wind transmission capacity is being installed by TenneT offshore northern Europe. Meg Chesshyre found out more.

Siemens is making good progress on the five offshore high-voltage direct current (HVDC) grid connections it is installing for the German-Dutch network operator TenneT. The grid connections have a total transmission capacity of more than 3.8 GW. In June, the 10,500-ton HelWin2 converter platform topside was loaded out from Heerema Fabrication Group's fabrication yard at Zwijndrecht, in the Netherlands.

The topside was installed last month (July), 85km offshore Heligoland, in the German Bight on a 4500-ton jacket, built by Heerema Vlissingen. The installation was be carried out by Heerema Marine Contractors' derrick barge *Thialf*. HelWin2 is an unmanned platform with a transmission capacity of 690MW, bridge-linked to HelWin1 (576MW), which was installed in August 2013. HelWin1 should be operational later this year, with HelWin2 following 1H 2015.

The HelWin2 transmission link will connect the offshore wind farm Amrumbank West, located in the HelWin cluster, to the German grid at the Büttel substation. There is capacity on the converter platform for further tie-backs. HelWin1 will convert input from the Meerwind Süd/Ost and Nordsee Ost wind farms, which are currently under construction.

Earlier this year Siemens installed the 12,000-ton BorWin2 (800 MW) offshore converter platform, 130 km off Borkum, built by Nordic Yards at its shipyard in Warnermünde, in Germany. Siemens is in a consortium here with Italian cable specialist Prysmian. This should also be on line in 1H 2015, as will SylWin1 (864MW), also built by Nordic, to be installed 160km off Sylt this summer. The projected windfarms in the BorWin wind farm cluster are: Albatros 1, BARD Offshore 1, Deutsche Bucht, Global Tech 1, and Veja Mate. For Sylwin, the wind farms are Butendiek, Dan Tysk, and Sandbank.

The most recent order has been for BorWin3 (900MW), due to begin commercial operation in 2019, where Siemens is in a consortium with Petrofac. This is still in the engineering phase. Meanwhile, TenneT is mulling bids for BorWin4 (900MW) with a contract award due shortly.

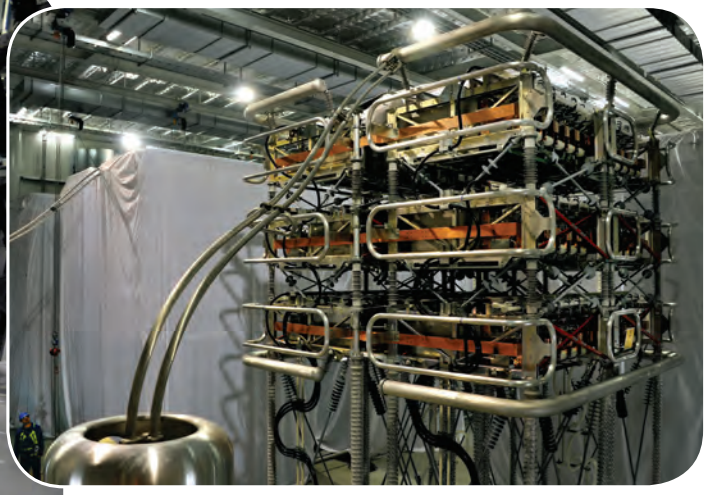
The HelWin2 converter platform being transported.

TenneT is also tying in DolWin1, 2, 3 cluster, 165km off Dollard Bay. DolWin1 was also built by HFG, for client ABB, with Heerema Zwijndrecht supplying the topsides, and Heerema Vlissingen the jacket. Commissioning is ongoing. The DolWin2 platform was built in Dubai. The sailaway was June 10. The projected wind farms in the DolWin cluster are: Borkum Riffgrund1, Borkum Riffgrund2, Gode Wind1, Gode Wind2, MEG Offshore1, Nordsee One, and Trianel Windpark Borkum.

The converter technology used by Siemens is called HVDC Plus. This is a voltage-sourced converter of the modular multi-level converter type. By contract with the conventional HVDC version, which can only be used in networks with sufficient short-circuit capacity, systems using HVDC Plus make it possible to start up island networks from scratch, an important prerequisite for operation offshore.

HVDC technology enables the alternating current generated by the wind farms to be converted to low loss direct current. Siemens says transmission losses per link are less than 3%, not including cable losses. First a number of transformer platforms arranged around the wind farm transform the alternating current before it is converted into direct current on an HVDC platform. It is transported to land via a submarine cable and then converted back into alternating current for onward transmission. HVDC technology is usually used when transmission cable lengths reach 80km or longer.

Power cables in the HelWin2 platform. Photos from Siemens.



The converter room on HelWin2.

The HVDC transmission market is expected to double within the next five years from a current €2.5 billion. In the last 40 years, "Orders for HVDC lines with a total capacity of 250 gigawatts (GW) are anticipated for this decade," commented Tim Dawidowsky, CEO Business Unit Transmission Solutions, Power Transmission Division, Siemens Energy Sector. "This is an enormous boom when you consider that a total of only 100 gigawatts was installed over the last 40 years." Siemens, as one of the biggest suppliers in the HVDC transmission sector has completed about 50 HVDC transmission projects worldwide, one quarter of which were in China.

Dawidowsky added that offshore wind was still a young industry with potential for standardization and cost reduction through mass production. Siemens itself is eyeing a target of cost reduction of between 30-40% by 2020, which would equate to a reduction to 10 euro cents per kilowatt hour by 2020. It was looking at solutions that could lead to a dramatic 95% reduction of the space requirement for converter platforms from >4000cu m to 200cu m, the first milestone being DC compact switchgear for 320kV.

"We feel confident that with the political frame being set not only in Germany, but also in the UK, the biggest market in Europe moving forward, offshore wind has a future. We would like to be part of that. We have to contribute on cost reduction. We are ready for that," Dawidowsky concluded. OE

Flying high

Chris Fleming explains how using remotely operated aerial vehicles for inspections are reducing plant shutdowns at oil and gas production facilities in the UK and around the world.

A Cyberhawk ROAV in flight.
Photos from Cyberhawk.

At oil and gas production facilities all over the world, maximizing uptime is of paramount importance. This all-encompassing driver, coupled with a total commitment to optimizing safety, means that there is an ongoing requirement to carry out close visual inspections of plant and equipment as part of a planned maintenance schedule.

'Traditional' inspection access methods

Traditional methods of accessing assets for inspection include rope access and scaffolding. Both approaches involve 'working at height' and require assets to be shutdown. Rope access inspection puts personnel at risk and can be time-consuming, both in terms of crew setup and inspection duration. Scaffolding is an expensive option and may take weeks to erect. Again, both options are hugely expensive and costs can run into millions of pounds or dollars a day in lost production output. The third traditional inspection technique is the use of full-size helicopters to inspect live flares at offshore oil and gas platforms. Again there are significant costs involved; there are also issues of availability. In addition to this, there is another serious problem relating to the method. A full-size helicopter inspection renders many safety-critical parts of a flare structure 'uninspectable' – examples may include the underside of the flare deck, access ladders, the flare stack/deck penetration and the flare boom.

A two-man team conducts a multi-scope inspection from the back of a vessel.

A new service keeping assets 'live'

Scotland-based Cyberhawk Innovations provides a new method of inspecting live and difficult to access assets. The method combines remotely operated aerial vehicles (ROAVs), highly skilled pilots and engineering experts to carry out close visual and thermal inspections of live assets that are 'at height' or difficult to access.

The ROAV inspection method offers operators a safe and comprehensive alternative to traditional approaches. Live asset inspection using ROAVs can also enable the operator to avoid the significant costs associated with asset shutdown. Unplanned shutdowns can often be prevented by using ROAV inspection

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to accurately assess the defective asset in question, rather than shutting the asset down at the first sign of an issue. Planned shutdowns can be made more efficient by using ROAV inspection to precisely identify the condition and specification of parts that may need to be replaced.

Background to ROAV inspection

The miniature flying vehicles or ROAVs use high-definition video and high-definition still and thermal cameras to provide detailed information for inspection purposes. Cyberhawk's battery-powered ROAVs weigh less than 2kg (about the weight of a large seagull) and are less than 1m in length. They are operated by a highly trained, two-man crew consisting of a highly trained pilot and a qualified inspection engineer. A two-man crew is critical for safe industrial inspection using ROAVs.

The ROAV is flown from the ground by a pilot who remains within visual line of site of the ROAV at all times. Typically the take-off and landing positions are close to the base of the structure being inspected. With the pilot's attention focused solely on the operation of the ROAV, the inspection engineer is able to concentrate on controlling the camera payload. This ensures that the ROAV team is able to capture clear Close Visual Inspection (CVI) images and produce a comprehensive and authoritative inspection report that enables asset owners to make informed maintenance decisions. With an experienced and qualified –typically ASME (American Society of Mechanical Engineers) and CSWIP (Certification Scheme for Welding and Inspection Personnel) – inspection engineer on every assignment and the presentation of an interim report before leaving the site, the customer is able to have a timely, peer-to-peer discussion about the condition of their asset.

Keeping an operational hub fully operational

Cyberhawk was recently called in by Statoil to provide detailed maintenance information on the enormous Sleipner A platform. It is hard to over-emphasise the importance and complexity of operations on Sleipner.

The platform acts as conduit and processing facility for a number of offshore and onshore installations that supply gas to as far afield as the UK and The Netherlands, as well as to the domestic terminal at Kårstø. Shutting down the Sleipner platform has a direct impact on distribution and supply to these other facilities and requires a major scheduling and coordination process that can take months.

Top: Cyberhawk's ROAV approaching the platforms underdeck.
Bottom: Structural inspection image of the platforms flare stack.

Due to the operational centrality of the Sleipner A as a 'hub', even when the platform is shutdown for turnaround, the flare system (which serves as a safety device should something go wrong) must still be capable of cold flaring potentially explosive gases. As such it remains 'out of bounds' to workers even during the shutdown. This means that the flare system is quite simply beyond the reach of 'traditional' inspection techniques, creating an uncertainty about its condition.

Avoiding costly shutdowns

Cyberhawk had already inspected flare stacks at Immingham and Kårstø at the other ends of the pipeline. Statoil was keen to use this method because live flare inspection eliminates the requirement to shutdown not only the Sleipner field but also the Troll, Draupner, Kårstø, Nyhamna, Langeled, Easington and Zeebrugge facilities, all of which feed in or out of the Sleipner A platform.

Getting down to work – working together

Following a HAZOPS meeting with representatives from operations, inspection, and maintenance, the Cyberhawk team completed the JHA (Job Hazard Analysis) under the guidance of the shutdown manager for the Sleipner platform who was instrumental in planning and coordinating the entire project. With the platform management having approved the permit, the inspection of the 120m-high flare stack and the three live flare tips was ready to begin.

Faced with some challenging weather conditions with winds blowing at 25 knots, the pilot and inspector set up their equipment on the nearby riser platform, some 200m away from the flares, and began flying operations. The Cyberhawk ROAV is able to cope with high wind conditions and to hold its position which makes for an extremely stable hovering platform.

In under a minute the small flying machine was hovering above the flare tower, capturing valuable inspection data. On the first flight, Cyberhawk used an infrared thermal camera to detect internal burning in the flare tips, a condition known as 'burn back.' Soon after this, the camera system was changed and still photographs and video were captured of the tip and flare deck revealing minor damage to the radiation panels. All three flare tips were found to be in good condition allowing future turnarounds to be revised with this new

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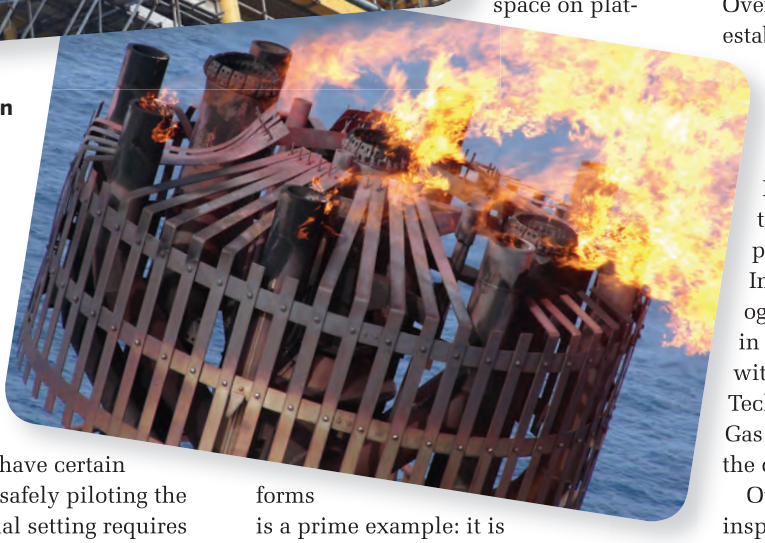
inspection knowledge.

On the Sleipner, each flight lasted less than 15 minutes and the team was able to inspect all sides of the asset from the tips down to the water line. This highlighted some areas of corrosion to the jacket and damage to the ladder cages. Before leaving the Sleipner platform, Cyberhawk delivered a field report highlighting areas of concern to target in the next turn-around. This is the company's standard practice and ensures that key issues are highlighted before the Cyberhawk team leaves the client's asset.



Top: Image taken during the inspection of the underside of the platform bridge. Bottom: Close visual inspection of a live fare.

Although ROAVs have certain automated features, safely piloting the ROAV in an industrial setting requires a high degree of pilot training and skill. These elements are required to accurately and consistently position the ROAV close to the asset and to ensure it can respond safely to unexpected events, from a gust of wind to signal interference. Cyberhawk refer to this as the ability to fly in full 'manual' mode and this is a cornerstone of its pilots training regime. Certain asset inspections, such as the underdeck inspection of an offshore oil rig, require 100% manual flying, and, especially in this case, a high level of pilot skill is vital to safe operation. This level is considerably above that tested and certified by Civil Aviation Authorities, and Cyberhawk has developed its own in-house training program to ensure that it can safely deliver services to industrial clients such as oil and gas and electricity companies. For example, to fly offshore, Cyberhawk pilots must pass four levels of internal training and certification over-and-above that mandated by the CAA.

Inspections that create real independence

Over the past four years, Cyberhawk has carried out work for all six supermajors across the UK, Europe, Middle East and Asia. The company continues to look for ways in which it can add value to its proposition by improving its customers' operations – right down to the most practical issues.

Limited bed space on platforms is a prime example: it is an issue for all operators, risking a 'bed bust' for all non-essential projects. In order to alleviate the problem of onboard accommodation, Cyberhawk has been focusing efforts in further developing its inspection methodology to allow greater independence from the platform.

In April 2014, Cyberhawk was called by an oil and gas supermajor to conduct a close visual inspection to quantify a workscope for fabric maintenance. The scope of work included CVI of the platforms flare, flare boom, platform bridge link, underdeck, jackup legs, jacket on the wellhead platform and the conductor guide frame. Cyberhawk operated from a supply vessel, providing the same standard of inspection imagery as previous ROAV inspections; it meant that the inspection could be completed without affecting the platform's operations or bed space.

Thousands of images and high-definition video of the platform were captured, allowing a full inspection report on all of the requirements set out in the scope of work. By operating from the back of a vessel Cyberhawk's inspection team was able to control the angle of the line of sight by moving the vessel around the platform. The result was a more detailed inspection of the platform's underdeck and splash zone. A previous inspection of an identical scope of work took a six-man rope access team over three months. By contrast Cyberhawk was able to complete the inspection in just 10 days. It all adds up to greater efficiency, improved safety and considerable cost-savings. Operators can now carry out detailed multi-scope inspections without any effect on operations, logistics, bedspace or the welfare team.

Tried, tested and proven

Over the last four years, Cyberhawk has established the use of ROAVs for CVI and thermal inspection of onshore structures at oil and gas installations all over the world. The first deployments of micro multi-rotor ROAVs in the oil and gas industry were at onshore refineries and processing plants in the UK in 2010. In 2011, Cyberhawk took its technology offshore in the North Sea. Then in late 2012, Cyberhawk was, together with asset management company Stork Technical Services, awarded an Oil and Gas UK Award for Business Efficiency in the offshore industry.

Over 200 flares alone have been inspected by Cyberhawk in the UK, mainland Europe, the Middle East and Asia. Like the ROAVs themselves, the compelling proposition of improved safety, operational efficiency and higher quality of engineering data is now reaching more places than ever before. OE

Chris Fleming *serves as operations director at Cyberhawk Innovations Ltd. A CSWIP-qualified plant inspector, Chris has over 18 years of experience working in the oil and gas industry, having worked in Asia, America, Australia, Europe and the Middle East.*

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(check one box only)

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- ☐ 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
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- ☐ 110 Production
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Norway's challenges and opportunities

Challenges to produce new areas, like the Barents, and extend the life of more mature regions, are high on the agenda for Norway's Petroleum Directorate. Elaine Maslin reports from the Underwater Technology Conference in Bergen.

Subsea technology has transformed Norway's oil and gas industry, helping to realize resources that would otherwise have been left in the ground, says Norwegian Petroleum Directorate (NPD) director Ingrid Sølvberg.

Since 2010, the total production from subsea completed wells has exceeded the production from platform completed wells, with the majority of the increase from gas. Subsea oil production has remained stable since 2006.

But there are also challenges, Sølvberg, the NPD's director for the Norwegian and Barents seas, told Bergen's Underwater Technology Conference in June. Norway's basins, the North Sea, Norwegian Sea, and Barents Sea, have varying degrees of maturity, and continued focus on implementing new technology, as well as ensuring co-operation between operators, some of which are new to development operations on the Norwegian Continental Shelf (NCS), will be key to their long-term future, she said.

Ingrid Sølvberg, director for the Norwegian and Barents seas, Norwegian Petroleum Directorate. Photo from UTC.

The basins

There is still a significant remaining resource potential in the North Sea, Sølvberg says. "It is a curiosity that the giant Johan Sverdrup discovery was part of production license 001 – the first license awarded on the NCS in 1965 to Esso—and was proven roughly 45 years later," she says. "The Sverdrup success is a good example of the importance of thoroughly examining areas we thought were well explored."

In the Norwegian Sea, about one third of the expected resources are sold and delivered. "Until now gas discoveries in the deep water area have been smaller than expected."

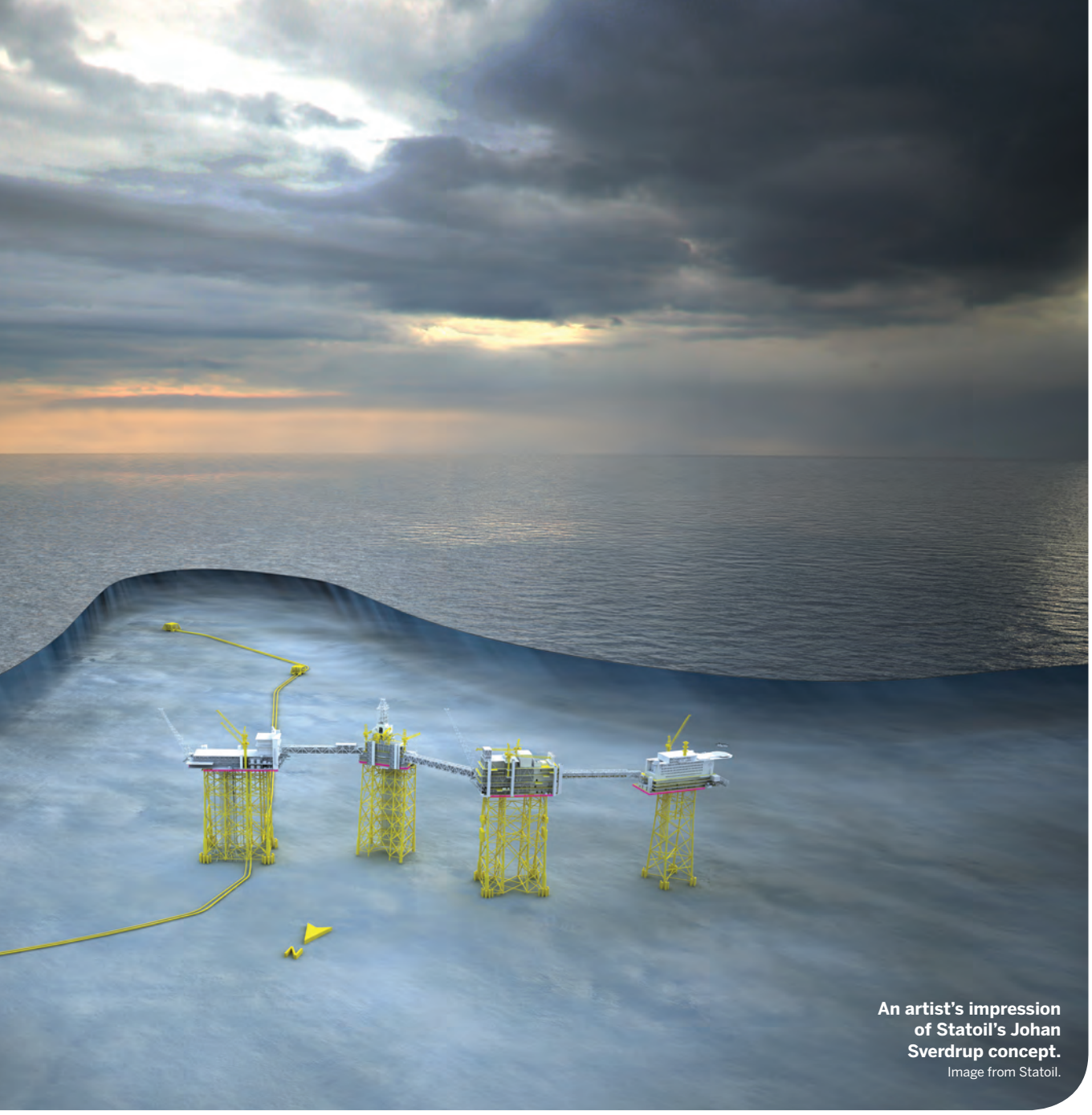
However, she adds: "The NPD still sees a large remaining potential in the Norwegian Sea. VNG's recent oil discovery Pil in the Njord/Draugen area demonstrates that there is yet more to find."

In the Barents Sea, only 2% of the expected resources are sold and delivered.

"The center of gravity for undiscovered resources has gradually moved north. It is here, in the Barents Sea, that the potential is greatest—and it is also here the uncertainty is greatest," she said.

Maintaining production

Field life on the NCS has proven to be much longer than originally estimated, with the total resource estimate having increased by 70%, compared to field plan for development and operation (PDO) estimates.



An artist's impression of Statoil's Johan Sverdrup concept.
Image from Statoil.

The resource increase has been helped by a focus on research and development and adopting new technologies, Sølvberg says.

Gas and water injection has also been more efficient than anticipated and continuous improvements in reservoir understanding has led to drilling more wells than originally planned as well.

The trend is likely to continue, with many fields in production or under development today expected to provide about 50% of the predicted production in 2030. But this will require continued efforts to extend field life and find ways to increase recovery, Sølvberg says, adding that there are about 165 projects currently being planned to improve recovery from producing fields.

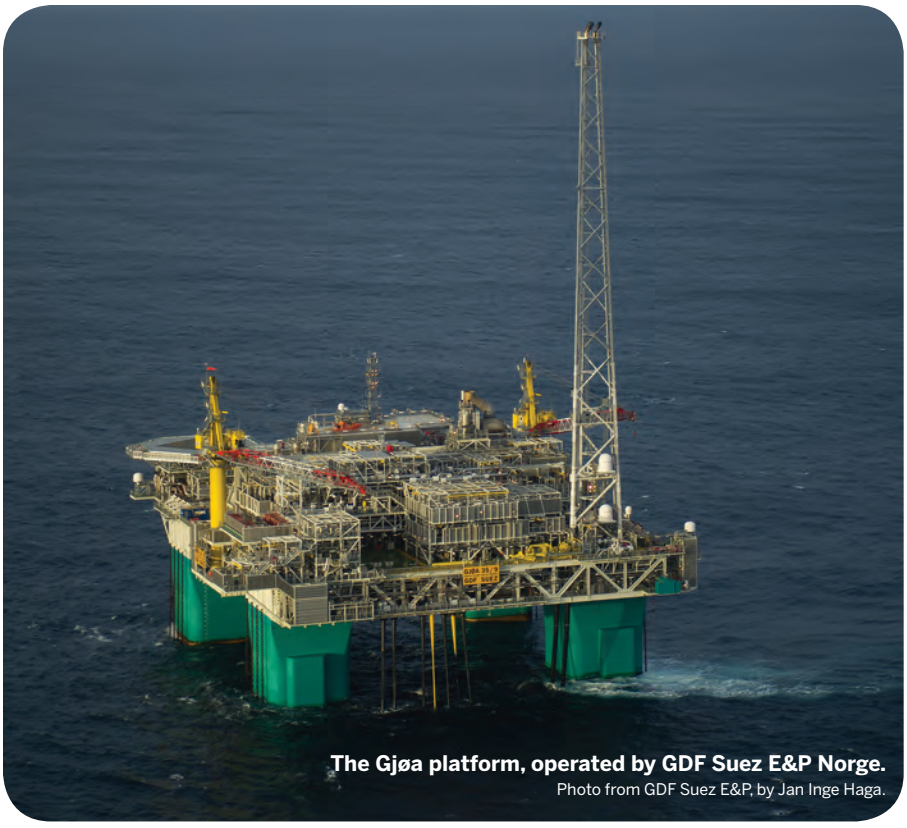
Norway's maintained production rates will also be aided by new major fields such as Johan Sverdrup and Johan Castberg, as well as further new discoveries. Beginning from 2025, Norway's undiscovered resources will need to be tapped to maintain the country's production levels, Sølvberg told UTC.

The cost challenge

To achieve this, there are challenges, including overall costs, as highlighted by Statoil's Anders Opedal (see p. 108). "For a producing field, today's unit cost is nearly three times the cost [that it was] 10 years ago," Sølvberg says. "As an overall trend, we see that unit costs increase in line with the oil price. The cost increase eats up the profitability effect of an increased oil price. Projects also become increasingly vulnerable to a drop in oil price. If this trend continues, realization of future projects is increasingly threatened by too low profit margins."

Companies are trying to implement stronger capital discipline. But the NPD is concerned that if capital discipline is too strong, it could result in short-termism and pricing of risk could become too conservative.

A specific cost challenge for subsea oil fields is that they produce on average about 50/50 water and oil, making water production an increasing challenge for future recovery, as subsea fields move into decline. "Cost efficient technologies for removing water or in the wells can have a big potential to obtain good



The Gjøa platform, operated by GDF Suez E&P Norge.
Photo from GDF Suez E&P, by Jan Inge Haga.

resource management," Sølvberg says.

Another concern for the NPD is the number of license owners with little field development experience on the NCS. The number of license owners on the NCS doubled between 2002-2007, with 58 license owners now operating on the NCS.

There are currently 13 fields with PDO approval today, she says. These have a total of 22 license owners, 16 of which are considered to have limited development experience on the NCS. Of 21 discoveries in a mature (pre-PDO) planning phase, there are 26 license owners, of which 21 are considered to have limited development experience from the NCS. "This puts demand not only on the newcomers, but also requires that license owners and contractors with experience from the NCS to demonstrate a will to cooperate and transfer experience," Sølvberg says.

Tie-backs

Another trend is tying-in third party resources. This has helped to increase operational life and tail-end production on host fields. But, there are challenges, specifically around lack of commercial agreements. "This can be due to conflicting interests regarding use of spare capacity to increase recovery from host field versus hosting third party resources. It can also be due competition for capacity by two or more third parties," Sølvberg

says. "Another part is related to use of existing infrastructure vs building new. Area solutions to establish new infrastructure may involve many companies with different strategies. It can be commercially challenging to coordinate terms and schedules."

To address this, in 2012, the NPD established an area forum in the Gjøa area, called Q35, in order to coordinate development of several discoveries and maximize use of existing infrastructure. The NPD is now considering similar initiatives for other areas on the NCS.

The Barents Sea

The Barents Sea offers the greatest potential on the NCS. There has been exploration activity in the Barents Sea since the fifth concession round in 1980. Optimism was initially high, with several gas discoveries in the 1980s. Interest then waned and after a number of dry wells were drilled and not a single well was drilled in 1994-2000. The government suspended activities in 2001, while an impact assessment for year-round petroleum activities in the Barents Sea was drawn up, and in December 2003, the area was reopened for exploration.

"Today, optimism is back in the Barents Sea. In the last three years more than 20 wells have been drilled. The number of exploration wells recorded last year were the highest ever and we may break this record already this year," Sølvberg says. So far in 2014, four exploration wells have been completed and three are in progress. During the next two years 15-18 wells are planned, and more drill or drop decisions will be made.

"The Johan Castberg area has more than 500MMbbl to be developed. The Wisting and Gohta discoveries are exciting. Results from ongoing wells like Apollo, Hanssen, Gohta appraisal and later Alta will give important information in order to evaluate the development potential in these areas."

Apart from the oil price, technology development and area solutions, to reduce unit costs, are key to the Barents Sea's future, Sølvberg says.

"The combination of shallow reservoirs, low pressures, and long distances call for development and implementation of new technology. In the Barents Sea, the development of subsea separation, boosting, and compression technology could prove important to develop new discoveries," she says.

The lack of gas infrastructure in the region is a particular challenge. "Today's infrastructure – mainly the Snøhvit LNG facilities—cannot make room for new gas until earliest 2045. This could become an obstacle for further exploration and development. Therefore, area solutions and coordination across licenses is vital."

With high cost levels and the industry seeking to reduce economic exposure, there will be significant opposing forces trying to find solutions across production licenses, making the NPD's task to develop the Barents Sea holistically crucial, she says.

Conclusion

"Both the emerging Barents Sea and the aging part of the NCS introduce new challenges, but we believe in the opportunities. We believe development of technological solutions that go hand in hand with good area solutions is the key to success. The NPD expects license owners to cooperate with each other, contractors, and authorities to find coordinated and holistic solutions." OE

What will it take to develop offshore heavy oil?

The Mariner heavy oil field took 40 years, 12 oil companies, five seismic surveys, and 18 exploration/appraisal wells to get to where it is today. Ingolf Søreide explains how heavy oil production has improved and where it is still challenged.

The Mariner development concept. Images from Statoil.

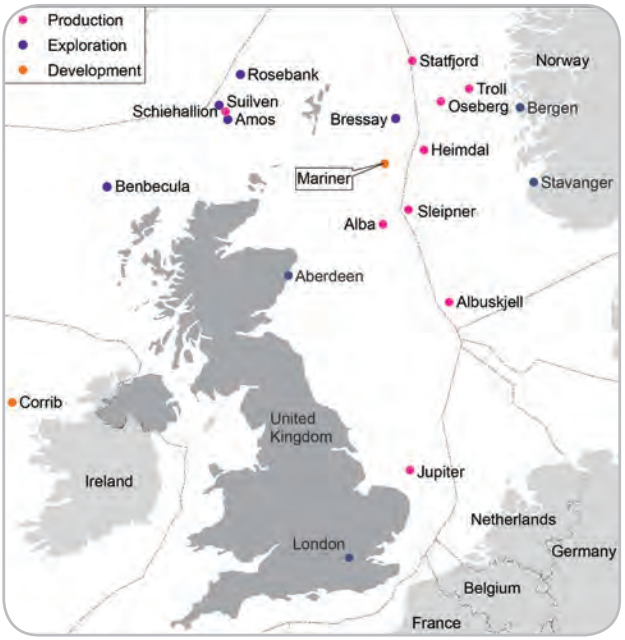
It's mid-1977 and a geophysicist is analyzing 2D seismic data acquired in UK Block 9/12. The survey happened to include some data from the neighboring block. In this 9/11 Block data, the geophysicist discovers a feature that is promising enough to persuade Union Oil management to acquire a license.

Plans to drill were quickly drawn up and the semisubmersible *Dixilyn Field 97* was chartered to evaluate the prospect. The first well in 1981 hit oil. Unfortunately, the rig was also hit when a supply boat collided with it. After a visit to the shipyard, three more wells quickly followed, two of which tested promising amounts of oil. The only problem was that it was heavy, 14° API, in fact. Not like the light 38°-40° API found in Brent and Forties.

Both Union Oil and the company who did the original survey, Seismograph Service Ltd., are long gone. But Mariner, the field they helped find, held an estimated two billion barrels of oil.

Fast forward 40 years to 2017. A brand new six-leg platform has been installed in 110m of water. There are three modern rigs on site and a large floating, storage and offtake unit (FSO) to take the produced oil away. The development cost Statoil and partners JX Nippon and DYAS in excess of US$7 billion. So why did it take 40 years, 12 oil companies, five seismic surveys, and 18 exploration/appraisal wells to reach this point?

The answer lies in the heavy oil. These types of reservoirs are typified by low flow rates and early water breakthrough, often within a few months. Once water does break through, it completely dominates



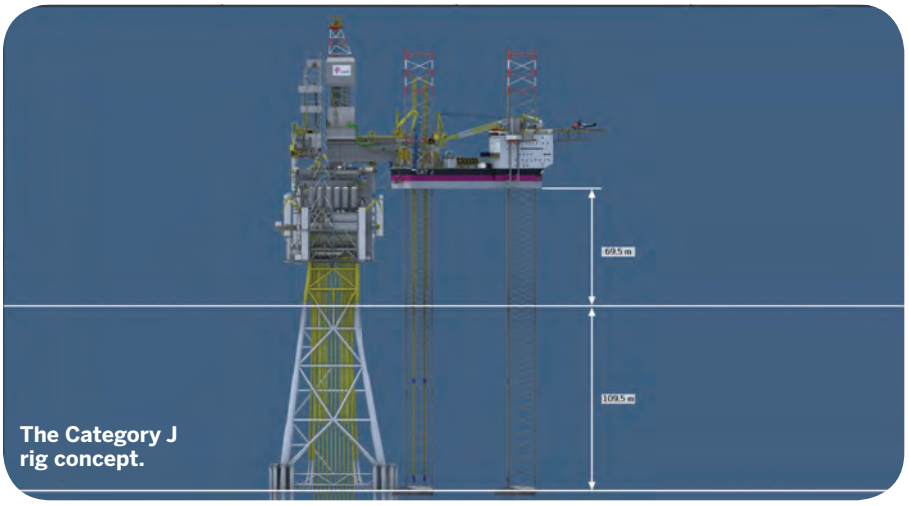
Mariner's location in the UK North Sea.

Statoil's Mariner development up close

The development of the Mariner field will contribute more than 250MMbbl reserves with average production of about 55,000bbl/d over the plateau period from 2017-2020. The expected date for production start is 2017.

The concept chosen includes a production, drilling and quarters (PDQ) platform, based on a steel jacket, with a floating storage unit (FSU). The topsides are being fabricated by Daewoo Shipbuilding & Marine Engineering in Korea. The FSU is being built by Samsung Heavy Industries, also in Korea. Spain's Dragados Offshore was awarded an engineering, procurement and construction contract for the steel jacket in cooperation with the UK offices of Canada's SNC Lavalin. Offshore installation of the platform jacket is scheduled for mid-2015, followed by topsides during 2016.

Drilling will be carried out from the PDQ drilling rig, with a jackup rig assisting for the first 4-5 years. Statoil is planning to use a new category J rig on Mariner, operated by Noble Corp. The category J rigs



The Category J rig concept.

A Category J rig, artist's impression.

the production. In addition, energy is required to lift the oil, since it is unable to flow on its own. Wells are commonly equipped with expensive downhole electrical submersible pumps. Working in harsh downhole conditions, the pumps need regular maintenance and replacement using expensive rigs. Once the oil is on surface, the challenges continue. Separating heavy oil from water is difficult and water disposal is a challenge. As if that was not enough, the refiners would rather take the light Brent, and heavy crudes often sell at a discount.

So what made the difference on Mariner? In one word, technology. Specifically, the application of tools such as multi-lateral branch wells, autonomous inflow control devices and a novel rig to change out pumps when necessary. Modern advanced seismic surveys have enabled us to see reservoirs that were invisible to the specialists in 1977. Another game changer is a well design that injects light condensate downhole, mixing with the heavy oil. The resultant product is a blend that refiners are very happy to take.

So is it case closed for heavy oil? Unfortunately, not yet. Mariner made it because it holds 2 billion bbl. What will it take to unlock smaller offshore deposits?

Certainly, subsea well and production technology are likely to be key. Increasing the recovery rate has to be at the top of the list. Steam assisted gravity drainage is commonly applied onshore, but offshore the energy costs are prohibitive. Techniques such as polymer flooding are showing promise, but application offshore needs improvement. Mariner will keep producing for at least 30 years, and in that time it will see many new technologies implemented.

I suspect the answer lies in the focused application of all the technologies mentioned and many more. If shales or heavy oils and the like are what the future is pinned on, something has to change. The message is repeated often. Operator and service partners must work closely to develop the tools badly needed. Operators themselves will have to work closely, regardless of commercial affiliations. The importance for our children's energy future may just usher in a new way of working together. As I have said on many occasions, "we are in this together." Oh, and a higher oil price would be nice, but we leave that up to the gods of supply and demand. OE

Ingolf Søreide *gave a keynote speech about heavy oil at the SPE's European Artificial Lift Forum in Aberdeen, SPE EuALF 2014, on 17 June. He is a vice president with Statoil, heading up the UK North Sea Mariner field development, which received government approval in February 2013. Søreide has almost 30 years' experience in the oil industry, mostly at Hydro and Statoil. He has been involved in R&D in Statoil and is member/chairman of the board of directors in Christian Michelsen Research. He recently moved to Aberdeen to lead the Mariner project through the execution phase. He holds an MSc and a PhD in Petroleum Engineering from the Norwegian University of Science and Technology in Trondheim, Norway.*

will be able to operate at 70-150m water depths and drill wells down to 10,000m. Category J is a tailor-made jackup rig for operations in harsh environment on both surface- and subsea wells in the shallow-water segments on the NCS.

The overall development proposal includes 50 wells and 92 sidetracks at Mariner and four wells at Mariner East. More than 140 reservoir targets for production or injection are planned for Mariner. While the number of well slots at the platforms is less, this will be solved using multi-branch technology, side-tracks and reuse of slots.

Mariner is on the East Shetland Platform of the UK North Sea, about 150km east of the Shetland Islands. It consists of two shallow reservoir sections—the deeper Maureen formation, at 1492m, and the shallower Heimdal reservoir, at 1227m. The oil is heavy with API gravities of 14.2° and 12.1° and viscosities at reservoir conditions of 67cP and 508cP, respectively for Maureen and Heimdal.

Statoil is the operator of the field with 65.11% equity, with partners JX Nippon Exploration and Production (UK) (28.89%), and Cairn Energy (6%). ▪

Liftboat used for geotechnical work off US Atlantic coast

The *Inez H. Eymard* lift boat.
Photo from Nick Welz, Tetra Tech Inc.

By Rami Mohsen & Nina Rach

DIMENSIONS
- Length (overall): 113ft
- Beam (overall): 70ft
- Depth (barge only): 9ft

HULL & DECK
- Tonnage: under 200 tons
- Central open deck area: 2800sq ft
- Side auxiliary deck area: 2274sq ft
- Usable deck area: àbout 4000sq ft
- Deck load: 422,000lb

LEGS
- Number: 3
- Length: 175ft
- Diameter: 54ft

CRANES
- Main: (L200-100): 110 ton w/ 100ft lattice boom
- Aux: (F60-70): 30 ton w/ 70ft boom

ENGINES
- Main: 2 x Cat-C-10
- Generators: 2 x Cat C-6
- Est. speed: 6 knots in max. 5ft seas

JACKING
- Max. water depth: 130ft with 15ft air gap
- Max. sea conditions: 5ft seas

Dominion Virginia Power is using L/B *Inez H. Eymard* for geotechnical site work this summer.

Throughout July, crews aboard the 110-ft. long liftboat acquired core samples for a proposed wind turbine construction project 27 miles off the Virginia coast. The crew also obtained core samples off the Virginia National Guard's Camp Pendleton, where distribution lines serving the project will come ashore.

Dominion required geotechnical borings in a wide, near shore swath, ranging 300 to 3300ft from the shoreline, and used different vessels, depending on water depth. A hydroacoustic monitoring buoy is also deployed.

The 100ft-long utility boat *Megan T. Miller*, owned by Miller Marine Services, is conducting piezocone penetration tests along the cable route.

The *Megan T. Miller* has a 4-point anchor system, an articulating A-frame on the stern to manipulate survey equipment, and a knuckle crane aft.

A smaller vessel, the *Moreen Yvette*, was considered for near-shore geophysical surveying operations, but ultimately not used.

L/B Inez H. Eymard

The US-flagged vessel is an offshore construction jackup built in 2009 at the Marine Industrial Fabrication shipyard in New Iberia, Louisiana. The research vessel is owned and managed by Offshore Marine Contractors and is one of eight, 175-ft class liftboats in its fleet.

The self-propelled, self-elevating vessel planned to drill up to four geotechnical

borings 27 miles offshore. The plan also included up to 11 near shore borings to evaluate the site proposed for the turbine foundations and distribution cable.

The vessel extends three, 175ft-long legs to the ocean floor to stabilize and raise itself. Each leg has 26ftx14ft pads to facilitate jacking up in soft soil conditions and minimize leg penetration. It can work in water to 130ft deep with 15ft air gap.

L/B *Inez H. Eymard* has approximately 4000sq ft of usable deck space and the aft deck has ample space to work and store equipment. The vessel's moon pool allows drilling through the hull rather than using a cantilever over the side. Additionally, the main deck acts as a stable, non-floating platform in comparison to a standard vessel subject to the sea conditions.

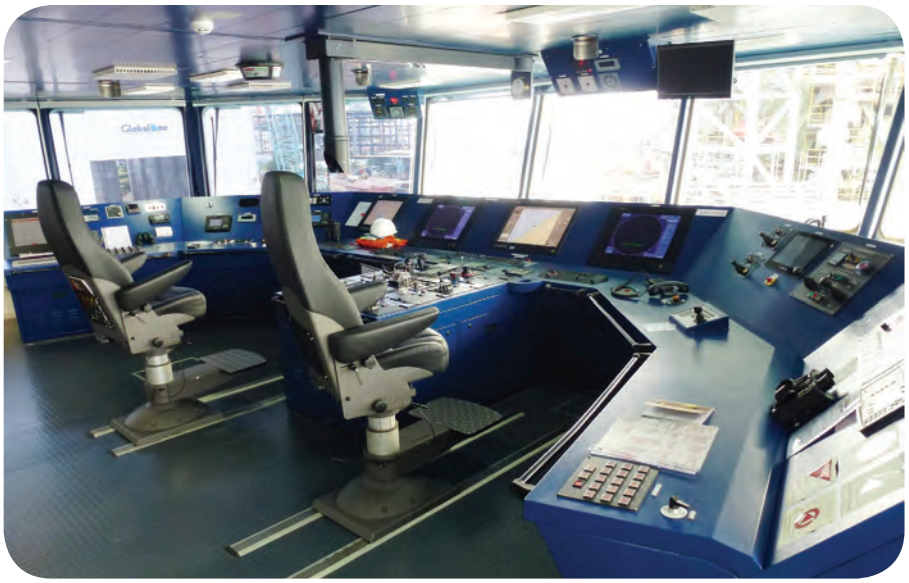
The vessel is equipped with a 110 ton main crane and a 30 ton auxiliary crane. The main crane, with a 100ft lattice boom, has a dyform 34LR wire rope with a working strength of 39,280lb. The auxiliary crane, with a 70ft boom, has dyform 18-wire rope with working strength of 12,960lb.

Vessel positioning was accomplished with a wide-area differential global positioning system (DGPS) with Fugro StarFix satellite positioning system corrections. This primary navigation system uses survey-grade DGPS to correct raw satellite data. Differentially-corrected positions are passed to the onboard navigation computer running integrated navigational software. The DGPS corrections are supplied to the system using the Fugro STARFIX II.

Fugro used a skid-mounted, Failing 1500 offshore drilling rig for the borings using wet, rotary drilling methods. The drilling equipment included mud pump and mud mixing systems developed by Fugro for offshore geotechnical operations. Different types of drill bits and sampling systems were loaded aboard the vessel as well as a 5000lb laboratory testing cabin. The Failing 1500 offshore rig is 42ft long. and weighs 21,000lb. The diesel powered rig is operated by a six-person crew including two drillers and four helpers for continuous, 24-hr operation, 7 days/week.

Borehole drilling included soil sampling and downhole piezo-cone penetration tests (PCPT).

In clay soils, Fugro was instructed to take 5m samples along the borings. The cycle comprised 1 x 3m PCPT followed by 2x 1m samples. The objective is to achieve a recovery of at least 80% of the 1m-long samples.



The bridge of L/B *Inez H. Eymard*. Photo from Offshore Marine Contractors Inc.

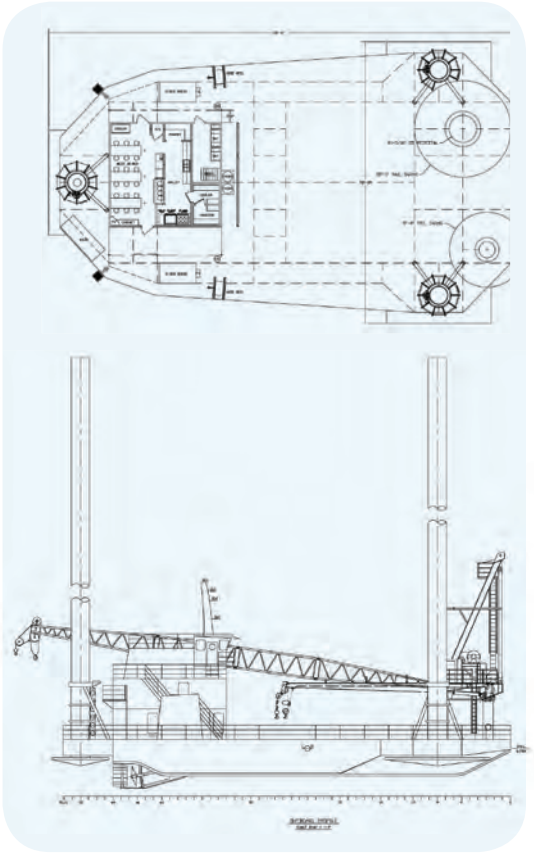
Fugro planned to have a modified California clay sampler onboard the vessel; this sampling technique uses a split-barrel sampler to obtain undisturbed granular soil samples. Fugro also provided a thin-and thick-walled, wireline, 57mm percussion sampler, which allows for relatively undisturbed driven tube samples to be collected in granular, relatively dense soils, typically fine sands and cohesion-less silts.

The geotechnical investigation was carried out as part of the Virginia Offshore Wind Technology Advancement Project, for which Dominion has secured grants totaling US$51 million from the Department of Energy. Pending the results of the investigation, Dominion plans to build two, 6Mw wind turbines on the proposed site and conduct tests on design features intended to lower the cost of construction, reduce maintenance and withstand hurricane-force winds.

Dominion also holds the lease on 112,800 acres of commercial wind area adjacent to the demonstration project. The company intends to use lessons learned from the turbines to guide the development of up to 2000Mw of wind turbine energy.

The two turbines would produce enough electricity to power 3000 homes. Dominion still needs to obtain several regulatory approvals. If approved by the Virginia State Corporation Commission and upon receipt of environmental permits, the turbines would be operational in 2017.

To develop the demonstration project, Dominion is working with a team of national and international organizations including, Alstom Power Inc., KBR, Commonwealth of Virginia Department of Mines, Minerals, and Energy, National Renewable Energy Laboratory, Virginia Tech Advanced Research Institute, Keystone Engineering, Newport News Shipbuilding, and Tetra Tech Inc. OE



***Inez H. Eymard* -main deck plan view, profile view.** From Offshore Marine Contractors.

Building an offshore HSEQ ecosystem

McMurdo Group's Remi Julien discusses how different technologies can converge to create a holistic offshore safety solution.

Offshore engineering offers many opportunities, but it can be fraught with challenges as well.

Whether operating an oil rig, monitoring a remote wind farm, building a marine pipeline or constructing a tidal energy facility, safety and reliability have extra layers of complexity when work takes place up to hundreds of nautical miles from shore.

Today, the various health, safety, environmental and quality (HSEQ) policies implemented rely on disparate, fragmented, and, in many cases, antiquated systems. Paper-based documents and maps are frequently used rather than software-based electronic forms and charts, standard definition cameras are still used instead of high-definition, infrared or night vision alternatives, or solutions from a multitude of providers just don't work together efficiently or accurately. Monitoring and ensuring the safety of activities offshore, as well as keeping an eye on any potential environmental impacts, also involves a vast array of services, including maritime search and rescue, traffic monitoring, maritime borders and zone surveillance, environmental protection services, and so on.

Too often, these services collect data independently and are not aware that sometimes they are processing the same information, reducing the ability to react effectively.

Due to the high costs involved in offshore oil and gas production and the potential risk to personnel safety, many oil companies, platform operators and rig owners use various asset protection systems to safeguard equipment and employees from a wide range of potential threats, from accidental collisions and illegal trespassing to intentional attacks.

An asset protection system can include fleet management, intrusion detection, employee safety, and environmental (oil spill) protection equipment. However, they are often treated as separate, distinct assets, owned and implemented by different departments. Fleet management, for example, may be an IT-sponsored project whereas intrusion detection is security-led and employee/environmental safety might be more regulatory driven.

In addition, offshore personnel and equipment work together in a highly intricate environment. With many HSEQ

Shore-side command centers are the hub for offshore communications and rescue coordination efforts. Images from McMurdo Group.

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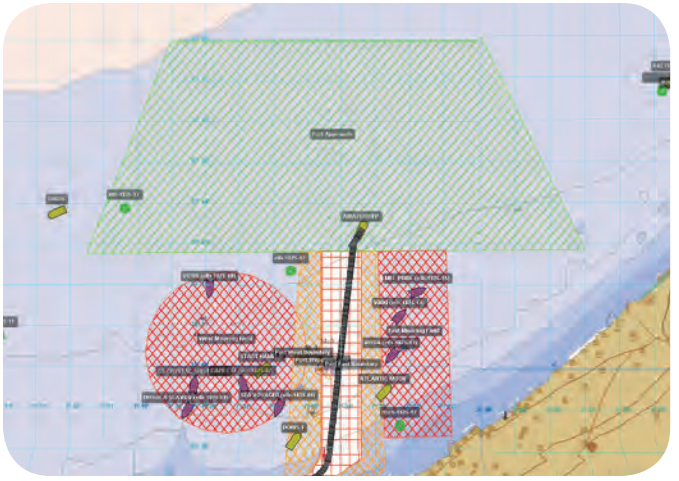
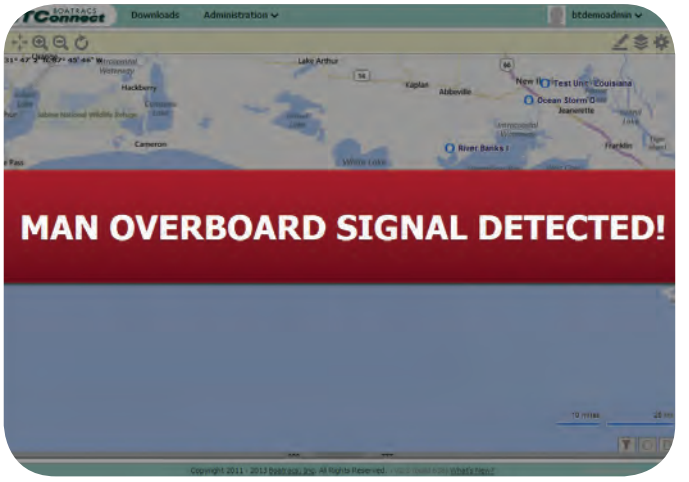
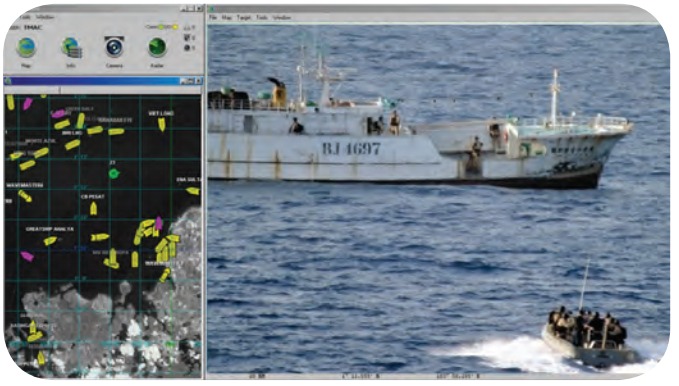


Fleet management software solutions provide real-time monitoring of vessels, traffic and activity in a designated area.



Man overboard beacons can send immediate notifications to nearby vessels and first responders to expedite rescues.



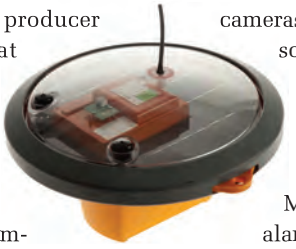
Intrusion detection systems can be integrated with fleet management software to enhance security and safety.

products and solutions available, creating harmony in this complex world requires interoperability and standardization —or convergence—of the different elements.

Safety ecosystem

Through the convergence and connectivity of the various applications, technologies, and processes, an HSEQ "ecosystem" can be created, and can be an integral part of day-to-day operations both offshore and onshore, as part of a tightly integrated asset management, security, and safety solution.

As an example, a large oil producer has offshore installations at risk of damage from fishermen, thieves, terrorists, and industrial sabotage. Security incidents have meant lost production days, risk to personnel, and threats to the company's corporate reputation in the region.



A proposed solution would be to implement an asset protection system incorporating the latest "detect, warn, and deter" capabilities to anticipate and react to potential safety and security threats. The system could combine different elements of fleet management, intrusion detection, employee safety, and environmental protection into a single system, which could be viewed and controlled from a centralized operations center.

In practice, this would involve:

- Using fleet management tracking and monitoring software, the location, activities, and movement of nearby boats, ships or other maritime vessels could be monitored in real-time. Geo-fencing and other perimeter control software features can help detect unauthorized entrance into secure zones.
- Information from traditional intrusion detection systems, such as radar, automatic identification systems, cameras (visible and infrared), and sonar can augment the view of vessels, and aircraft, in the area.
- In the event of a man overboard (MOB) situation, MOB beacons can set off alarms with both fleet management software and AIS transponders for increased employee safety and faster response and recovery.
- In the case of an environmental emergency, marine tracking buoys can be used to track and warn of oil spills or other navigational hazards.
- All the consolidated data is sent real-time via satellite communications or long-range radio to a shore-side command operations center, which uses vessel management software, data analytics, and 3D charting to determine the proper course of action. In the event of a security area breach, for example, warning or deterrence activities, such as security personnel dispatch, high-intensity spotlights or long range acoustic devices (LRAD) may be triggered. All of this activity can be recorded and stored for future usage.

Convergence is happening today

While there is still a long way to go before true interoperability is seen between solutions from different vendors, convergence, similar to the solutions outlined above, is taking place today with oil companies and rig operators from the Gulf of Mexico to the Middle East. By integrating features of historically different technology platforms into a cohesive HSEQ ecosystem, a more comprehensive, cost-effective, and interoperable solution is created—one that can streamline operations, protect assets, and save lives. OE

Remi Julien *is vice president, Corporate Development for McMurdo Group. He was previously CEO of Signalis, a maritime surveillance systems company. Julien is a graduate from Ecole Polytechnique and Ecole Nationale Supérieures de Techniques Avancées and holds a Master's in signal processing.*

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Building a safety case

Girish U. Pai, Devendra Awadhiya and Zubin Fatakia discuss the evolution of safety case in designs for offshore platforms.

Offshore installations are exposed to nature's fury all the time. The operations involve handling very heavy modules weighing tens of thousands of tons. Presence of hydrogen sulfide or other lethal gases in process streams pose serious hazards to people working there. Movement of tugs, barges around the installations further increase the accident potential. *Deepwater Horizon* brought out the dangers of oil spills, causing serious damage to flora and fauna in oceans.

Safety systems need to address all these hazards. All countries, therefore, have rightly formulated standards and regulations and established monitoring agencies to ensure safe conduct of offshore operations. Every country has its own legislations for safe design, construction and management of offshore installations.

US regulation

The first successful effort to improve safety was setting up the National Safety Council in 1913 to pool information. Government agencies such as the Bureau of Mines and National Bureau of Standards provided scientific support while universities also researched safety problems for firms and industries. In the 1960s, economic expansion led to rising injury rate. Hence, in 1971, the US Congress established the Occupational Safety and Health Administration (OSHA) to ensure that employees are provided with an environment free from recognized hazards, such as exposure to toxic chemicals, excessive noise levels, mechanical dangers, heat or cold stress, or unsanitary conditions.

In 1974, the American Petroleum Institute (API) published its Recommended Practice 14C, which covers recommendations for design, installation and testing of a basic surface safety system on an offshore production platform. In this recommended practice, basic concepts of a platform safety system are discussed and protection methods and requirements of the system are outlined.

After the 1988 Piper Alpha catastrophe that killed 167 people, API published its Recommended Practice 75, for development of a safety and environmental management program for offshore operations and facilities in 1991. It has been updated regularly since. The standard recommends that companies create a safety environmental management program (SEMP). API RP 75 is performance-based and insists on continuous improvement and effective communication.

Supplements to API RP 75

API RP 14J (1993)
Procedures and guidelines for planning, designing and arranging offshore production facilities, and performing a hazards analysis on open-type offshore production facilities.

API RP 76 (2004)
Contractor safety management for oil and gas drilling and production operations, first edition

In 2010, Bureau of Ocean Energy Management, Regulatory and Enforcement (BOEMRE) mandated that all references in the API RP 75 document cited as "shall" or "should" will be considered "must." In 2011, the US split BOEMRE into two organizations: the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE). Following the *Deepwater Horizon* event, BOEMRE implemented a requirement that safety cases be prepared for drilling operations. Companies can use the template from the International Association of Drilling Contractors (IADC), which is widely used.

Regulations in India

To ensure proper implementation of various aspects of safety in the oil industry, India set up the Oil Industry Safety

Overview of legislations in US, India and UK

	US	India	UK
Before	**NCS** - 1913	**Safety Council** - 1986	**Health & Safety at Work Act** - 1974 HSE & HSC responsible for enforcing the act
Before	**OSHA** - 1971		
Before	**APIRP 14C** - 1973 Design, installation & testing of basic surface safety system		
After Piper Alpha	**API RP 75** - 1991 Creation of a safety enviornmental management program	**PNG Rules** - 2008	MHSW Regulation - 1992
After Piper Alpha	**API RP 14J** - 1993 Supplement to API RP 75	**OISD** Competent authority for excercising powers & functions as stipulated in P&NG Rules 2008 •Codes API ((RP 75, 14J, 2C), ISO, OISD • Conventions MARPOL, SOLAS,ISM, MODU	Offshore Installation Regulation - 1995
After Piper Alpha	**API RP 76** - 2004 Supplement to API RP 75		PW Regulations & PFEER - 1995
After Deepwater Horizon	**BOEMRE** - 2010 Made all references in API RP 75 mandatory		OIW Regulations - 1996
After Deepwater Horizon	**SAFETY CASE made mandatory for driling operations**	**Guidance Notes of OISD** - April 2012 Mandatory certificate for "Fit of Purpose" status of oil installation	**SAFETY CASE - 2005**

Directorate (OISD) and gave it authority to formulate and coordinate the implementation of a series of self regulatory measures for enhancing the safety in the local oil and gas industry.

India's government also created Petroleum and Natural Gas (Safety in Offshore Operations) Rules, 2008, to regulate safety in offshore exploration, exploitation, conservation and management of petroleum and natural gas and matters connected therewith. PNG Rules, 2008, follow a goal-setting approach, i.e. what is to be achieved rather than prescribing specific solutions.

Solutions chosen by the operator shall be based on customary practice in the industry, requirements, and specifications appearing in other documents such as nationally and internationally recognised industrial standards (e.g standards like API, ISO, OISD), codes and conventions (e.g. MARPOL, SOLAS, ISM, MODU code). However, evidence in form of documentation, demonstrating that solutions selected by the operator fulfill the functional requirements of the rules, shall be maintained by the operator at all times. Safety systems of Indian operators such as ONGC and GSPC comply, among others, with API RP 75, API RP 14J and API RP 2C.

Guidance notes issued by OISD in April 2012 made it mandatory for operators to get a valid certificate issued by an independent party (including a classification society) to achieve the "fit for purpose" status for an oil installation.

UK regulations

In the UK, The Health and Safety at Work Act 1974 is the primary piece of legislation covering occupational health and safety. The Health and Safety Executive (HSE) with local authorities (and other enforcing authorities) is responsible for enforcement. The Piper Alpha disaster was a watershed event in UK offshore, which caused a paradigm shift in offshore safety systems not only in the UK , but in the offshore industry worldwide.

After Piper Alpha, the UK introduced the most comprehensive legislation for protection of workers and ensuring integrity of installations. A few of the regulations include:

- 1992: Management of Health and Safety at Work Regulations 1992
- 1995: The Offshore Installation
- 1995: Pipeline Works (Management and Administration) Regulations
- 1995: Prevention of Fire and Explosion, and Emergency Response Regulations (PFEER) 1995
- 1996: The Offshore Installations and Wells (Design and Construction, etc) Regulations 1996.

The most important of all, the Offshore Installations (Safety Case) Regulations 2005, came into force in 2006, which made it mandatory for the operator or owner to prepare a safety case and submit it to HSE for acceptance.

Safety case: For submitting a safety case, the operator has to prepare a detailed and structured argument to establish that the oil facility is safe. In general, a safety case should clearly describe the following elements:

- The system and its operational context.
- The safety claims and safety criteria.
- Hazard Identification and Risk Assessment.
- Risk control measures and their effectiveness.

Why the residual level of risk is acceptable:

- Roles, responsibilities, organizational safety policies and organizational safety management system.

The challenge is to present the

information in an easily accessible format, improve communication and involve a wide range of people in understanding important risks and issues.

A Safety Case must demonstrate that:

- Major accident hazards have been identified and that the necessary measures have been taken to prevent such accidents and limit their consequences for persons and the environment.
- Adequate safety and reliability have been incorporated into the design, construction, operation and maintenance of installations linked to major accident hazards.
- All necessary measures have been taken to reduce identified risks to as low as reasonably practicable (ALARP).
- It meets all regulatory requirements of the Petroleum Submerged Lands Act.

Workforce involvement

The operator has a duty to ensure and pay for the training of the safety representatives.

Secondly, the workforce is involved in developing the safety case for an installation. The safety case regulations require the operator both to demonstrate they have consulted with the workforce when preparing the safety case and to make copies of the accepted safety case available to them.

Benefits: Since safety case is primarily built from first principles and not from legacy standards, it can integrate safety evidence from diverse sources, such as trials, human factors analysis and operational experience.

- Safety Case acts as a focus for discussion between all stakeholders such as system designers, manufacturers, operators, managers and workers. The benefit in terms of increased communication is tremendous.
- Safety Case makes the implicit explicit. It documents existing implicit assumptions and risk acceptance judgments. This increases transparency.
- It is an opportunity for understanding limitations of current safety system and making improvements in it.

Safety Case vs. conventional approach: Conventional approach has focused primarily on prescriptive safety requirements, e.g. In India and USA, safety executives look for compliance with codes like API RP 75, PNG Rules 2008. With such approaches, operators claim safety through satisfaction of the regulator's requirements. With the introduction of safety cases, the responsibility is shifted back to the operators and it is up to the operators to demonstrate that they have an adequate argument of safety.

Why safety case is not widely adopted (beyond the UK): In principle, a safety case can be developed for any activity. However, in practice, they are generally only prepared for large, complex industrial or technical systems such as nuclear power plants, military and civilian aviation and offshore oil and gas installations. Such systems are complex, and, in the event of an accident, the consequences could be very severe.

Also, the use of API standards and related documents has been proven fairly successful. Although the *Deepwater Horizon* event was extremely serious, it was the first major blowout in US waters since 1969, with the Santa Barbara blowout. In 1999, a wellhead blowout occurred on a platform, which operated under safety case, at the Montara oil and gas field in the Timor Sea off Western Australia. The development of safety cases and the application of the subsequent safety case regimes is expensive, time consuming and creates a large amount of paper work. If it could be demonstrated that this investment truly improves safety then there would be no argument. However, there is no convincing evidence that either approach if clearly better than the other.

When all platforms are designed and operated to the same standards (mostly from the API) it is relatively easy to audit them. The auditor simply has to look up the appropriate code or rule, and he or she can come to a quick conclusion. Such is not the case with a safety case system, where each platform has its own unique program against which it has to be evaluated.

Conclusion

Safety systems continue to evolve as oil and gas operations become more challenging. World over, safety systems predominantly operate in a regime where the systems have to meet requirements of prescribed standards. However, the legacy standards may not meet the requirements of highly complex industrial or technical systems such as nuclear power plants, military and civilian aviation and large offshore oil and gas installations where the consequences of an accident could be very severe.

For smaller installations, the benefits of prescriptive safety systems outweigh the higher cost and time involved in building up a safety case. UK has made it mandatory for all oil installations to get a safety case approved by HSE. The US has made it mandatory only for drilling operations.

However, it is worth noting that a safety case preparation presents an opportunity to operators and contractors to have a reality check on their safety systems, look for gaps and improve safety with the active involvement of all stakeholders. A powerful safety regime is one which measures the performance of critical success rather than relying on occupational health and safety statistics. OE

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Networking pros abound, but beware of cons

Gregory Hale

There is no doubt networking plays a vital role in the offshore oil and gas industry right now and it will be even more important in the future. With the potential of remote management of multiple platforms from an onshore location, as well as cutting down on system real estate that can enable users to save on time and space to better communicate, the advantages far outweigh risks.

The latest technologies grant any offshore user the capability to view any and all aspects of the operation, beam back and capture data that will ensure a safe, smooth, productive, and more profitable operation.

But keep in mind there are risks.

First, there is the classic case of a flood of data washing ashore with no apparent rhyme or reason. Data without context.

Second, whenever you talk about networking, whether it is over the internet, within a system or wireless, you are talking about major security concerns, which can turn into huge safety issues.

You can take state-of-the-art technology and place it on your facility, but if you don't have staff that understand the key components of what they see and are able to put that into the proper perspective, you are flirting with economic and physical disaster.

> The answers are there, that is the easy part. The hard part is making the right fundamental decisions that take the technological results and put them into perspective.

This is where the human factor comes into play. People and technology need to mesh in front of a monitor. The answers are there, that is the easy part. The hard part is making the right fundamental decisions that take the technological results and put them into perspective.

Does the person know what to look for? Are the alerts coming in clearly enough? Is the operator staying on task or thinking about what he or she will be doing when the shift ends? All are key questions that should force operators to stay on top of their game.

Those same questions need to arise when talking about securing a network connection. Yes, the communication is available. And, yes, all the disparate systems are now able to talk to one another and get messages and commands across to one another, but security remains paramount so you can stay up and running and take share of all the advantages the technology has to offer.

VIGILANCE IS THE KEY

One latest attack, dubbed Dragonfly – discovered by Symantec and F-Secure – is a cyber espionage program targeting energy companies.

The attacker's approach is very strategic and almost surgical in how they are able to get into various systems. The Dragonfly group has a range of malware tools at its disposal and is capable of launching attacks through a number of different vectors.

Dragonfly's most ambitious attack campaign saw it compromise a number of industrial control system (ICS) equipment providers, infecting their software with a remote access-type Trojan. This caused companies to install the malware when downloading software updates for computers running ICS equipment, a Symantec report said. These infections not only gave the attackers a beachhead in the targeted organizations' networks, but also gave them the means to mount sabotage operations against infected ICS computers.

Dragonfly appears to have been in operation since at least 2011 and may have been active even longer than that, according to the report. Dragonfly initially targeted defense and aviation companies in the US and Canada before shifting its focus to US and European energy firms in early 2013.

With the manufacturing automation industry, including offshore oil and gas, losing around US$400 billion a year due to unplanned downtime from safety and security incidents, operators, engineers – everyone for that matter – need to be aware of what is happening, and keep everything in perspective and in context.

Showing a smart approach to networking will not only ensure a smoother running operation where everyone is in sync, it will allow users to bank their share of the $400 billion. OE REVIEW

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

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Integrating automation offshore

Peter Welander examines how the challenges of networking disparate elements are intense, but workable.

The offshore oil industry is evolving rapidly, as oil and natural gas now begins to flow from deposits considered impossible to tap just a few years ago. Production companies around the world are working to exploit fields in remote locations, in very deep water, and below huge amounts of rock.

At the same time, more production equipment is moving off floating platforms to the sea floor. In years past, a well that produced a mixture of oil, gas, and water would have to send the mixture to the platform for separation. Now that process can occur at the wellhead, with separate streams of oil and gas pumped to the surface.

The costs of maintaining offshore platforms and the people that operate them are sizable, and remain a driver for operators to find ways to move equipment and people off platforms - and even eliminate the need for them entirely. "It's a whole new business case for developing oil and gas," Ann Christin Gjerdseth, director, controls and data management for FMC Technologies, says. "The business case for placing production equipment subsea is a very favorable one with regards to cost and the environmental footprint. But moving more to the seabed brings a holistic challenge around automation, and that infrastructure needs to be designed to use more functionality. That's driving new thinking around automation."

INTEGRATION ON A GRAND SCALE

Getting oil from a wellhead on the sea floor to an onshore terminal, and eventually, a refinery, requires different processes that have to work together efficiently and safely. Simultaneously, the data also has to go to the enterprise.

When a main automation contractor or system integrator ties together such a large-scale project, invariably there will be some "black boxes" thrown into the mix. A black box could be a major piece of equipment or skidded subsystem (skids) designed to perform a specific function. It remains self-contained, with its own controller and small-scale automation system.

Such skids can perform their functions flawlessly; on the other hand, designers might not be aware of how it should fit into the larger automation scheme for the overall operation. To make it work, the integrator may have to unravel the system's programming and determine how to make it communicate with the larger system.

Some boxes are blacker than others, so the task might be simple or it might be a headache, but it probably involves writing specialized programming code just to talk to that device.

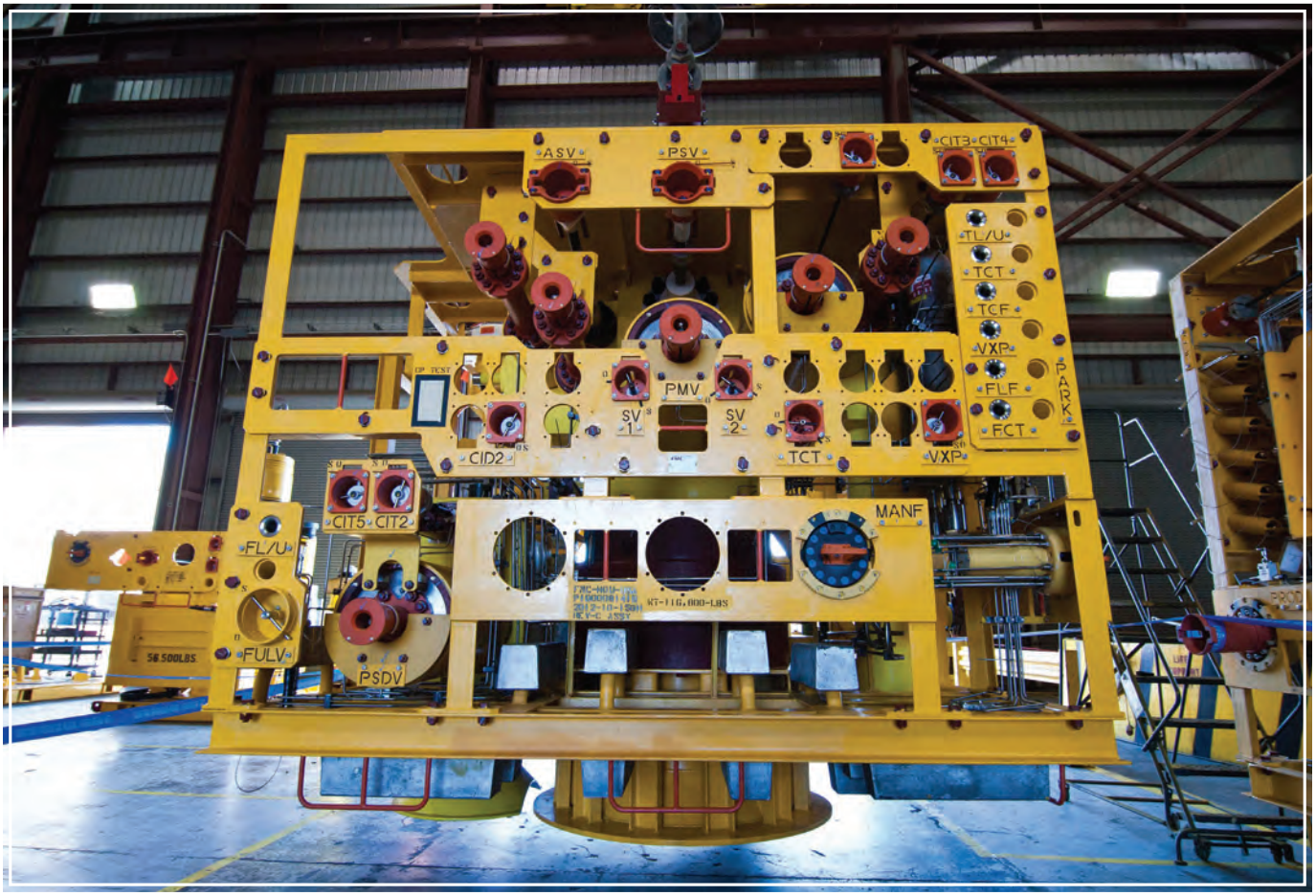
TECHNOLOGY DIFFERENCES

One challenge to offshore integration is that relatively few companies produce equipment for offshore installations. The companies that dominate the market in subsea equipment can be counted on one hand.

Lee Swindler, oil and gas program manager for Maverick Technologies, has worked on these projects firsthand. "I think it is because offshore rigs have tended to be built as a single isolated entity," he says. "Because of that, they tend to tolerate equipment that doesn't play well with others. They go to a single engineering company that uses a few select suppliers to design and build the entire rig, whereas onshore facilities tend to be put together more piecemeal.

"That is certainly a big difference with downstream, refinery-type plants where there are established communication and interface protocols that are commonly used and it allows you to mix-and-match suppliers and still end up with an integrated system. (Offshore) you're left trying to use a single supplier solution in a lot of cases in order to get it to integrate, and even then it's probably only doing part of what you need, or trying to figure out how to make things work together on your own, which can be time consuming and difficult."

A platform isn't a single black box, but a whole series of small, isolated systems that have their own controllers, Paul Bonner, oil and gas vertical leader for Honeywell Process Solutions, explains. "You've got compressors on platforms and you've got a third-party black box compressor control system," Bonner said. "There might be an anti-surge control system, or a separate safety interlock system, and so on. They're all different systems that you think of as being outside the distributed control system (DCS) but have to interface



As a part of creating production, here is a subsea production tree that mounts at the well head. Source: FMC Technologies

with it, and that presents a big challenge for getting the data back to the shore in a coherent form."

LOOK IN THE MIRROR

Others look at the situation and say these integration challenges are a self-inflicted problem — companies have to deal with black boxes because they buy black boxes. Gjerdseth says there are plenty of examples of alternate systems that integrate without all the headache because the operators chose an easier path.

"If you go to the Norwegian Continental Shelf, you will see that the tradition there for many years has been to integrate a lot of the systems and automation," she said. "There aren't many black boxes. But if you go into the Gulf of Mexico (GOM) and even the UK, you will see that they have used many suppliers and are have a lot of different vendors' systems as a result. Much depends on the philosophy of your whole system: whether you want one automation platform, or if you want every system to be proprietary."

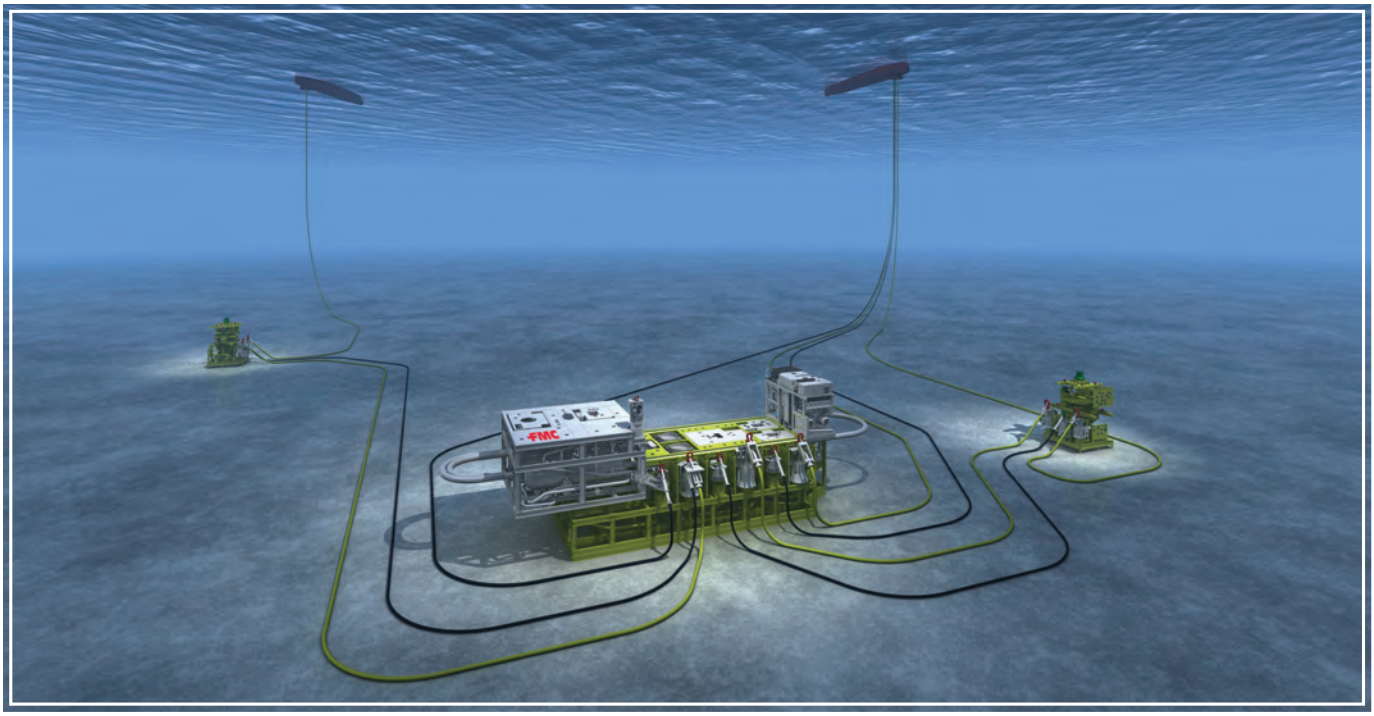
Gjerdseth's contention is that when planned well, a project may still have small pockets of isolated systems that need some extra work to bring into the larger control system. That effort can be minimized if there is a conscious effort from the outset to choose systems designed to interact.

On the other hand, poor planning has the opposite effect. Ben Trombatore, project manager for Mustang Automation & Control has seen appropriate care at a critical time can avoid problems when working with control systems connected to packaged equipment.

"The reasons for these challenges are not so much overcoming the technical hurdles, but rather not providing adequate attention to details," he says. "As any systems integrator will attest, data interface issues such as preferred communications protocol, data map structure, IP addresses, data security handling, time syncing, cabling specifications, and so on, need to be reviewed thoroughly and understood by both the equipment supplier and the systems integrator prior to start of work. Too often, companies rush to issue (purchase orders) to their equipment vendors with little or no attention to data communications. If these deficiencies are not caught and fixed during the factory acceptance test, then they will definitely pop up during commissioning and start-up, resulting in additional integration costs and quite possibly delays in start-up."

CREATING OPERATIONAL INTEGRATION

Memories of the *Deepwater Horizon* oil spill are still fresh enough to keep safety front and center for offshore projects. Integrating all the disparate control systems involved has to provide a means for operators to respond quickly to abnormal situations. Supporting this typically involves the creation of one overarching control strategy that can handle all the control, alarming, safety, and reporting functions for this huge collection of hardware and disparate systems that is designed with varying degrees of cooperation in mind. Without that, there can



An installation rendering of a subsea separation system used in Petrobras' Marlim field. Source: FMC Technologies

be major losses of efficiency and potential for disaster.

"If you're trying to piece together disparate parts to present a unified picture to the operator, it is more of a challenge," Swindler says. "Your goal as an automation engineer is to try and get the operator the information he needs to make the right decision at the right time, but you have to do it in a consistent manner so that the technology doesn't block his view and inhibit him knowing what's really going on out there. That's the challenge when working with systems that don't integrate together. If it was easy, anybody could do it."

Eugene Spiropoulos, senior technical solutions consultant for Yokogawa Corporation of America agrees. "You have disparate systems. You have the larger DCS you're trying to develop looking one way, but then you have the human-machine interface (HMI) interfacing with the skid looking another way. What you provide to the operators should be seamless. Not just the start and stop of the system. The faceplates and graphics of the system, the look and feel and style of the system should have the same style as the DCS itself."

The larger issue is that all the different systems have their own way of dealing with information. Each has its own way of treating diagnostic functions, but all of that has to be brought together into a unified system.

Honeywell, ABB, Emerson, Kongsberg, Siemens, and Yokogawa have all accepted the reality at hand. As Bonner says, FMC Technologies built most of the subsea equipment, so it's easier to work with them and use their system. He says that up until about a year ago, Honeywell would use Modbus to communicate with the wellhead skid. That, however, was a very manual operation that required a lot of work for optimal functionality. But then those DCS suppliers worked with FMC Technologies to eliminate that problematic step by adopting a new protocol.

"We took the FMC-722 protocol, and we've embedded that in our controller," he said. "So rather than having to go through a set of intermediate servers and other approaches, we now integrate natively with FMC Technologies. We can now take our DCS and plug it straight into our controller and talk directly to the FMC topside processing unit (TPU) and pretty well provide all the functionality of the configuration blocks."

CREATING ENTERPRISE INTEGRATION

Like every other area of process manufacturing, offshore oilfield operating companies are trying to create a higher level of information integration from wellhead to terminal to executive suite. Planners and others on the enterprise level expect current production and information to be available anywhere. Getting all that data gathered and turned into useful information in an environment where even the most basic communication is a challenge calls for a variety of solutions.

"Getting information from daily operations to the enterprise level involves a conversion of paring down of information into something that's specific for the business," Spiropoulos says. "At the top level, the guys that are working with SAP, Oracle, and so on, are not interested in daily flow rate. They're not interested in what the pressure was at noon. They want to know what the business effectiveness was, what the profitability was, what the energy management situation was. This involves getting information out of our control systems and also out of the third-party sub-systems, and cross converting the information into (key performance indicators, or KPIs) for the plant or the process that span different systems.

"This is where it becomes really valuable to guys at the enterprise level. The same way we automate the process, we want to automate the information. In the same way that the process controller knows what to do,

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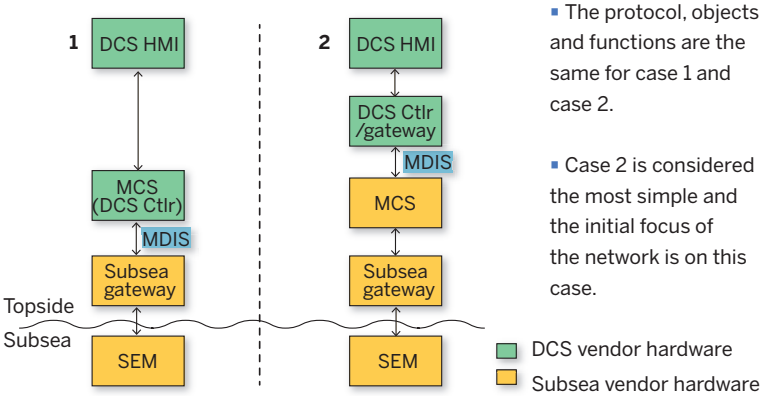

MDIS wants to create a bridge between subsea vendor hardware and the DCS on the platform and onshore systems. Source: OTM

the information layer knows what to do. We specify what is important for the KPIs and the planning layer. As the information is collected, our information layer converts that information into what's useful and pushes it to the relevant people or the relevant systems."

DATA ON THE MOVE

Integrating all these systems involves moving data. Getting it from the sea floor to the platform is manageable enough using fiber optic cables, but traversing long distances from a platform to an onshore facility can be more challenging. The amount of data has increased, but the ways of moving it have not kept pace. Bandwidth is a major bottleneck. Bonner said the GOM has been a struggle.

"With the exception of one major company that has invested in fiber optic lines out to their platforms, everybody else in the Gulf is relying on one of two satellite companies," he says. "They're getting a data rate of around 1-1.2Mb/sec, which is about what you probably get from your home internet provider. You've got massive amounts of data on the platform, and massive amounts of data on shore, and you've got basically a drinking straw between two fire hoses. Given that amount of bandwidth, you have to be very selective about what you pipe back to the shore."

COMPREHENSIVE SOLUTION

When enough companies contend with the same problems again and again, often they will get together to create some sort of standard that can help smooth out the differences. Such has been the case for offshore installations. A group of organizations have worked to create more than one standard for integration:

- IWIS (Intelligent Well Interface Standard)
- SIIS (Subsea Instrument Interface Standardization)
- SEAFOM (fiber optics)
- MDIS (MCS-DCS Interface Standardization)
- SWiG (Subsea Wireless Group)

One group that is currently active is the joint industry group MCS-DCS Interface Standardization (MDIS) network, which works towards bridging subsea vendor hardware and the DCS on the platform and onshore systems. Rachael Mell is a consultant for OTM Consulting, a division of the Sagentia Group, which manages the MDIS program. "We hear, time and time again, that the operating companies want more standardization, especially across projects, because every time you start a new project offshore, you have to do a lot of engineering work just to make sure the equipment you want to use from different vendors will click together and talk to each other," Mell says.

The group includes participation from the operating companies, subsea vendors, and DCS vendors and

A FUTURE STANDARD

Choosing OPC UA is definitely a decision based on the long-term future rather than choosing something that might work now, but will be made obsolete quickly.

At the moment, there is far too little equipment available to make an implementation practical, but the vendor community is working on it. Down the road, it is easy to see things falling into place one by one.

"The objects work group is looking at designing the software objects for the major pieces of subsea equipment that this interface needs to control," said Rachael Mell, a consultant for OTM Consulting, which manages the MDIS program, which chose OPC UA as its single communication standard that all MDIS participants could use as a unified platform standard.

"They finalized the binary objects at the last meeting, and now they're converting those objects into OPC UA language and going through them and making sure they make sense to everybody involved. The OPC Foundation is taking the object design and converting it into the OPC UA format, and the working group is reviewing that. At the last meeting, they went through the valve object to confirm that they're all happy with it. Now that will go to review for the whole MDIS network, and every company will get to submit comments. Once finalized, that will be the object that goes into the standard.

"The validation work group is working on the interoperability test, which is planned for June, 2015. The subsea vendors and DCS vendors will bring their equipment to test the interface. That will verify that what we've done, so far, really works and that the vendors will be able to implement it. One thing that would motivate the vendors more would be if they had a date. We would like one of the operators to say, 'We want to use the MDIS standard on this field at this time.' That's something we've been pushing the operators for lately, but we can't really get yet," Mell says. Writing standards is by nature a slow process, and then the vendors have to create products to be implemented by the operators. It doesn't happen overnight, particularly when the standard involves so major a change as adoption of OPC UA.

"OPC UA's promise is that it's object based — it's a unified architecture in that it's one system that can do all the different things of the other flavors," Eugene Spiropoulos, senior technical solutions consultant for Yokogawa Corporation of America, says. ▪

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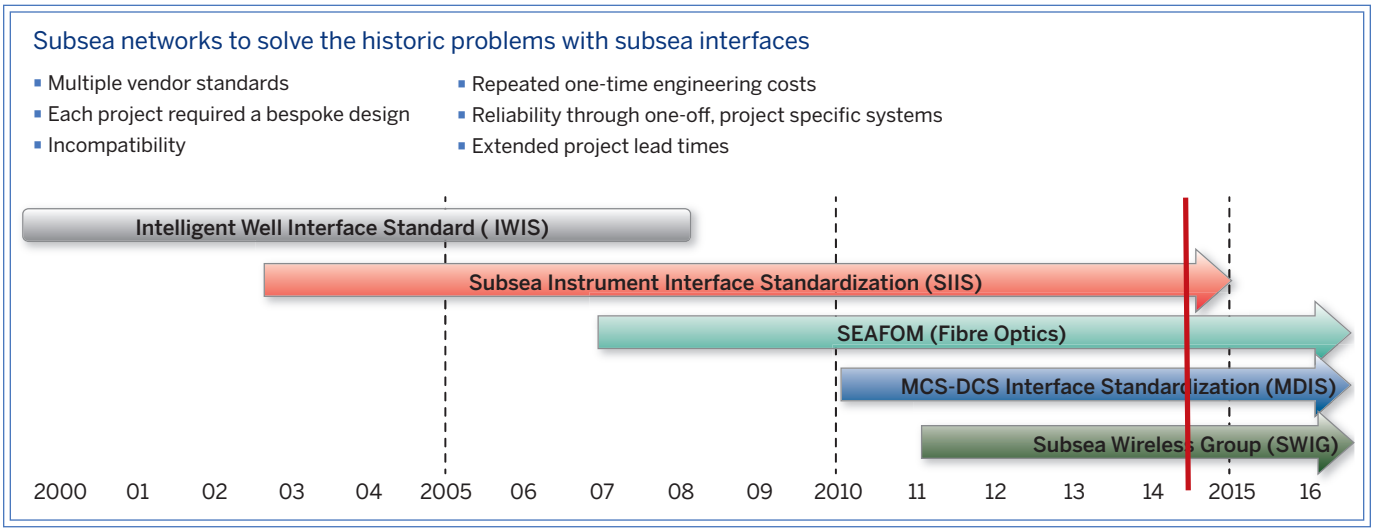

A group of organizations worked to create more than one standard for integration. Source: OTM

integrators.

"It's fairly even between the three groups and we have major representation from the vendors and operators," Mell said. "Given the nature of the work we're doing, the vendors get involved a bit more, and then we rely on the operators to make a decision when there are things the vendors can't decide on. The operators are the customers, so they get their say at the end of the day."

One of the major steps the group took was identifying a single communication standard that all participants could use as a unified platform. In 2013, it selected the OPC Foundation's UA (Unified Architecture) out of a list of eight candidates. OPC UA integrates functionality between the individual OPC Classic specifications, which also deals with communication between software models, into one extensible framework. One of the reasons why MDIS chose OPC UA is that it relates to its ability to work with objects.

Thomas Burke, OPC Foundation president and executive director sees this adoption as a critical step as MDIS builds a strategy to provide interoperability across multivendor multiplatform systems.

"One of the main features of OPC UA is the information model architecture, which allows suppliers to model complex information into the OPC UA namespace," he says. "A vendor can now build a product that understands the intricate details of a complex data model, and using OPC UA allows other applications to connect and understand the syntax and semantics of the data/information.

"We have been collaborating with upstream oil and gas standard organizations all the way down to subsea vendor oil and gas providers. This will allow easy interoperability and understandability of the data and the metadata associated with all of the simple and complex objects in the architecture."

Paul Hunkar, president of independent software consulting firm DS Interoperability has been assisting the MDIS standard formation. From his viewpoint the challenge OPC UA helps solve isn't about control strategy; it's about interfacing.

"In older systems interfacing was accomplished by mapping tags," he says. "This tag mapping was prone to errors and incorrect assumptions. Also multiple communication interfaces (protocols) were used, and if a vendor didn't support one of the interfaces, there were additional complications. OPC UA provides a robust high-speed communication infrastructure. For MDIS, it is expected that the interface will be operating as part of a gateway or controller in the subsea system and in a DCS controller or programmable logic controller (PLC) on the topside system. The beauty of OPC UA is that it supports multiple platforms and can be implemented across all of these hardware solutions. By using OPC UA, vendors are free to continue to use the hardware they are most comfortable with, or the system that the customer specifies."

DOWN THE ROAD

Using OPC UA is "a great and noble idea and definitely the way to go, but there aren't a lot of critical systems in the field built on that system at this time," Yokogawa's Spiropoulos says. "Adoption will be slow, unless a real use case emerges from the users."

Revisiting this topic in another five years will likely produce a vastly different discussion. By that time, the standard writing processes will be farther along, vendors will be making related products, and there will be time to implement some of the new systems. Older fields will continue to operate using legacy systems, but those with a long enough operating life will eventually come around.

In 10 years, subsea fields may be invisible as more equipment moves to the seafloor and platforms disappear. Operators will have seamless control over large fields from onshore control centers away from the dangers and inconvenience of living on a platform. Thinking about the future, Gjerdseth says, "What we're really offering here is subsea production, processing, and intervention. Automation is a key enabler to get those offerings to market." OE REVIEW

Peter Welander is a freelance writer and editor specializing in industrial automation.

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All eyes on deck

Ellen Fussell Policastro examines how video surveillance meets DCS integration for faster event response.

The US Energy Information Administration names Angola as the second-largest oil producer in Sub-Saharan Africa. When an international oil and gas conglomerate in Angola became concerned about security on a floating production storage and offloading unit (FPSO), operations managers responded by asking to increase visibility to the operation — a costly move in such a remote location. The unit operators needed to keep an eye on their safety system, especially flame monitoring, as well as the workstation onboard the FPSO.

In response, an industrial ethernet provider for the oil and gas industry teamed-up with a control and instrumentation systems provider to implement the critical process control system for the platform. Using a video encoder, the system migrated from analog closed-circuit television (CCTV) to internet protocol (IP) networks. This allowed seamless integration of the process control systems and IP video systems, giving the FPSO alarm-to-video monitoring.

The good news is operators can now see more and respond faster to potential safety and security events. The bad news is distributed control system (DCS) integration could bring more potential for cyber security threats.

DETAILED PROJECT PICTURE

An IP camera is a digital video camera that can send and receive data via a network and the internet. The Angola project required 232 IP video cameras linked to heat sensors at each workstation. With the trigger of a heat sensor came an alarm and recorded video with time-stamping mechanisms.

Operators can view an event remotely, even days after, because the system logs and stores event information. They can also search for event information in a central database and play it back for details about what triggered the event. "This gives the user not only a way to view in real time exactly what is happening in the field, but a way to take corrective action from the control room, or immediately send the proper team to respond," said Thomas Nuth, manager for global oil and gas systems at Moxa, Inc., in Brea, California.

The video recording function for the control system provider's video management system offered historical playback and search of events that triggered the system. "We make use of the video encoder to convert the video analog signal to TCP/IP," says Francis Goh, of Yokogawa Electric International, in Singapore. "Detectors are also segregated in zones," he says, "and

Video surveillance sees use for monitoring coastal traffic monitoring and preventing vandalism in a protected area — controlled via internet protocol. Photo from VideoTec.

we even have event video recording for a duration of three minutes."

Harry Hsiao, product manager of the industrial video networking division at Moxa, worked with Yokogawa Engineering Asia, combining the DCS system with IP video. "The benefits of the rugged CCTV systems are short response time in the field of sight because the video image pops up automatically once an event has happened, which means less money lost in system downtime or broken equipment," he says.

When the DCS receives an alarm, it sends an event trigger to the surveillance server. The video surveillance system immediately retrieves video streams from the relevant industrial video encoder unit and initiates recording and playback functions. At the DCS control center, a built-in viewer allows engineers to review event logs and corresponding video in a single glance.

IP VIDEO, DCS INTEGRATION

Video cameras have two important roles in offshore security plans, said Gianni Viero, a vice president at VideoTec, a CCTV industrial video equipment provider, headquartered in Schio, Italy. "The first is assessing detected alarms and confirming their cause; the second is surveillance," he said. With live video stream that monitors activity approaching the platform, operators can immediately "direct a response force to counteract and confront any intrusion," Viero said.

While the camera isn't a magic pill, it can be a key part of the revolution that's happening in oil and gas – the addition of ethernet.

"While DCSs are redundant and reliable, they don't have a lot of bandwidth, but IP video does," Nuth says. And with the integration of fiber and internet, the DCS can grow more intelligent." Integration happens by adding another layer of networking or an auxiliary network. "So if the wireless system fails, operators will still be able to manage," Nuth says. And if there is an explosion or spill, they can now respond faster to fix the problem.

"The great thing about ethernet is it's attached to sensors in the field," Nuth said. "Cameras can be tethered to these meters, and because the cameras watch over the DCS and part of the DCS operation, operators can use them to survey everything in the core operations through supervisory control and data acquisition (SCADA)." Operators in the control room can see what's happening on the platform through a live video feed. "It's a network of controllers feeding into the central human machine interface (HMI) to a computer screen, and one person can control what's going on. But now with the cameras, they can see more."

Before IP video surveillance, "these systems were all proprietary, so if you had one particular vendor, you had to use that vendor's cabling system, coax, VHC, and twisted pair wires," Jonathan Pollet, founder and executive director at Red Tiger Security in Houston, says. "The biggest benefit of the convergence to IP is the ability to deploy video to places that are not geophysical—limited.

"With the older systems that ran over coax, you could only push that video out so far. Then you needed to repeat that signal every 1700ft. With IP cameras you can go as far as you want either with fiber optics, category 5 or 6 cable, or wireless, putting a canopy over the rig."

EYE ON SAFETY

Fred Czubba, senior business development manager for oil and gas at Phoenix Contact in Middletown, Pennsylvania, has seen how cameras can save lives offshore. "In the North Sea, temperatures are close to subzero," Czubba says. "I wouldn't want my operators out at night to investigate a problem when I can have a camera out on the catwalk. The two highest quantifiable sensors offshore are fire and gas. So if either of those detects a leak, they will show in which zone, but not the actual location. If you have a camera at that location, you can actually see the white cloud where something is leaking." Nobody would need to enter a potentially dangerous situation.

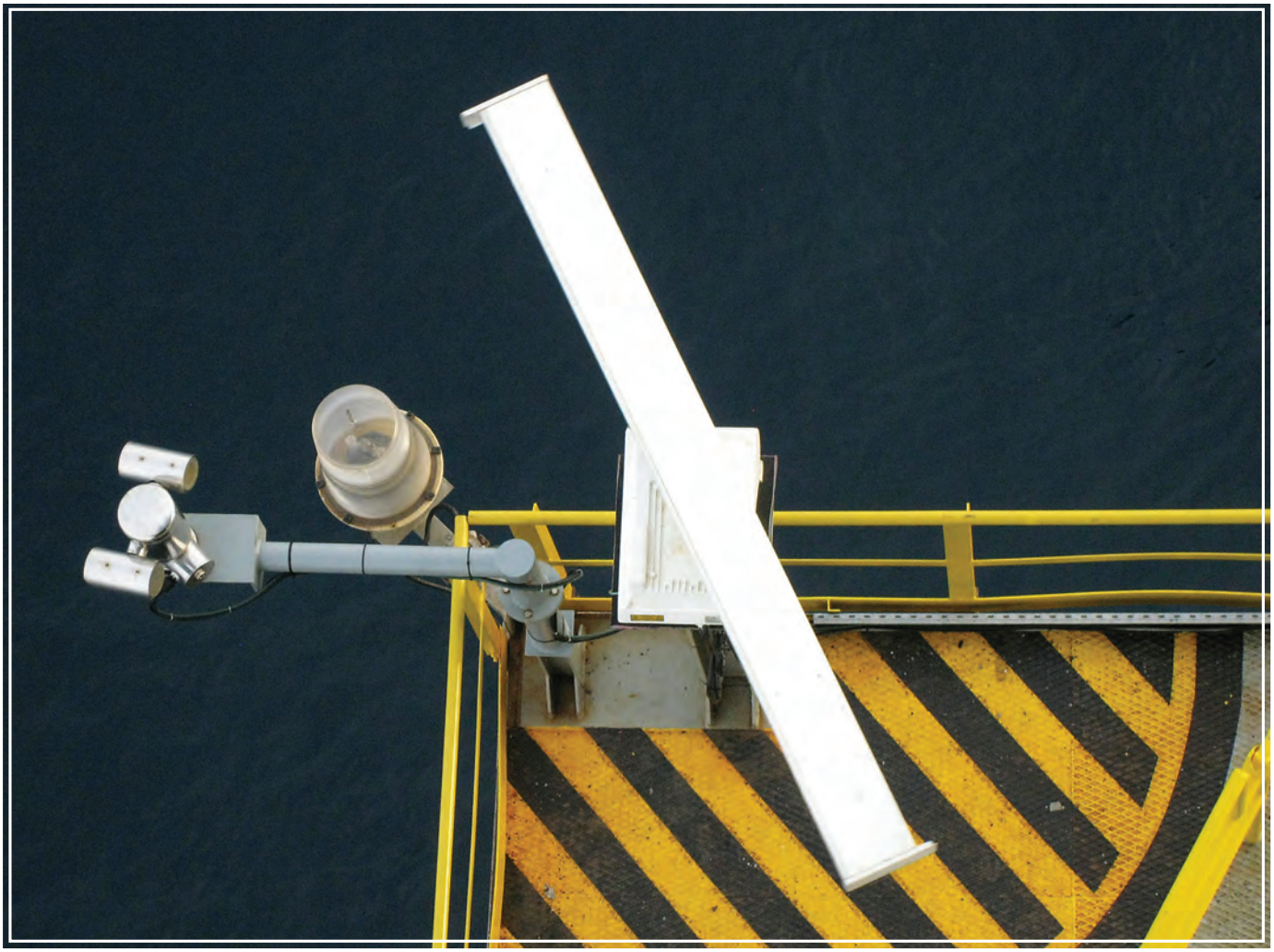
"The flare always burns with a little pilot light, and if one of those turbines shuts down, that flare becomes a 600ft candle," Czubba says. "If the compressor fails, suddenly you're venting pure gas into the atmosphere. With the cameras, you can see the pilot went out, and you know you need to reignite it."

The project in Angola had 224 workstations attached to temperature and pressure meters with a high probability of flame damage or flare-up. "Since they are so remote, you can't have somebody managing each workstation at all times," Nuth says. If the meters exceed a certain pressure and temperature, the sensor will send an alarm via remote monitoring to the control room. They'll also receive the alarm by phone and email. Simultaneously, the cameras will come on. Then the event log will turn on, so this event will be saved at the moment it exceeds a certain pressure and heat level. Not only can operators see immediately what has happened, they can post-reference to see how the problem occurred. They can assess the problem remotely and implement corrective action.

> "The great thing about ethernet is it's attached to sensors in the field... Cameras can be tethered to meters. Operators can use them to survey everything."

PHYSICAL INTRUSION, CYBER CONCERNS

If someone approaches a rig, operators will be alerted. Some cameras have microphone capabilities and can allow operators to speak to potential intruders. When fishermen or tugboats tie off onto the rig in rough seas,



operators can use a high-powered speaker to ask them to identify themselves. The camera's recording capabilities come in handy for security issues as well. "As soon as an object changes the pane of view (someone approaching), operators have a cache of the previous 10 seconds, the actual action, and the following ten seconds after the object or person leaves the pane of view," Pollet says.

But while integration can be great for business and provide a cost-effective way to monitor the platform, cyber intrusion through the network is a big concern. Rigs are often targets for malicious activities, especially in remote areas, and one way to gather intelligence is to hack into a camera system. "Terrorists might want to take over the rig's assets or personnel for ransom, which has actually happened at an oil refinery in Europe," Nuth says. "They might have planned a successful infiltration by hacking cameras to see where the assets are located. But the video encoder converts the video feed from the camera to the recipient — whether in the control room or on the PC at home — so nobody can intercept."

However, "encoding the video only protects the video content from being hijacked or altered in transit from the camera to the software," Pollet says.

"It only protects the video stream. If the video system is integrated with the control system, hackers would not be targeting the video content itself, but instead would use vulnerabilities in the video servers, workstations, and cameras to move from the video environment to the control system environment."

Any IP-enabled system that integrates with or affects the DCS should go through a comprehensive cyber risk assessment first to ensure design does not open the system to additional risk, Pollet says. He's seen actual cyber intrusions in which hackers used the video surveillance camera to get into the system.

"My main concern with this movement to IP is to make sure it's isolated and not connected to the control system. Unfortunately installers want the ability to go in remotely — through the internet."

While Pollet wants to keep the networks secure with separate systems, he understands why the industry is reluctant to separate them — because of the "limited bandwidth, limited communications, and one satellite uplink. So they end up converging all those systems to save money," he said.

Pollet believes this to be a problem in terms of security: "The danger here is that you've put two different systems that serve two different functions on the same cyber network. If the video surveillance system is not locked down and secure, someone could access the video system from a business network or Internet and use the video system as a way to link themselves into the DCS system. If it's all integrated together, and I can access the video system, I'm on the same network. So

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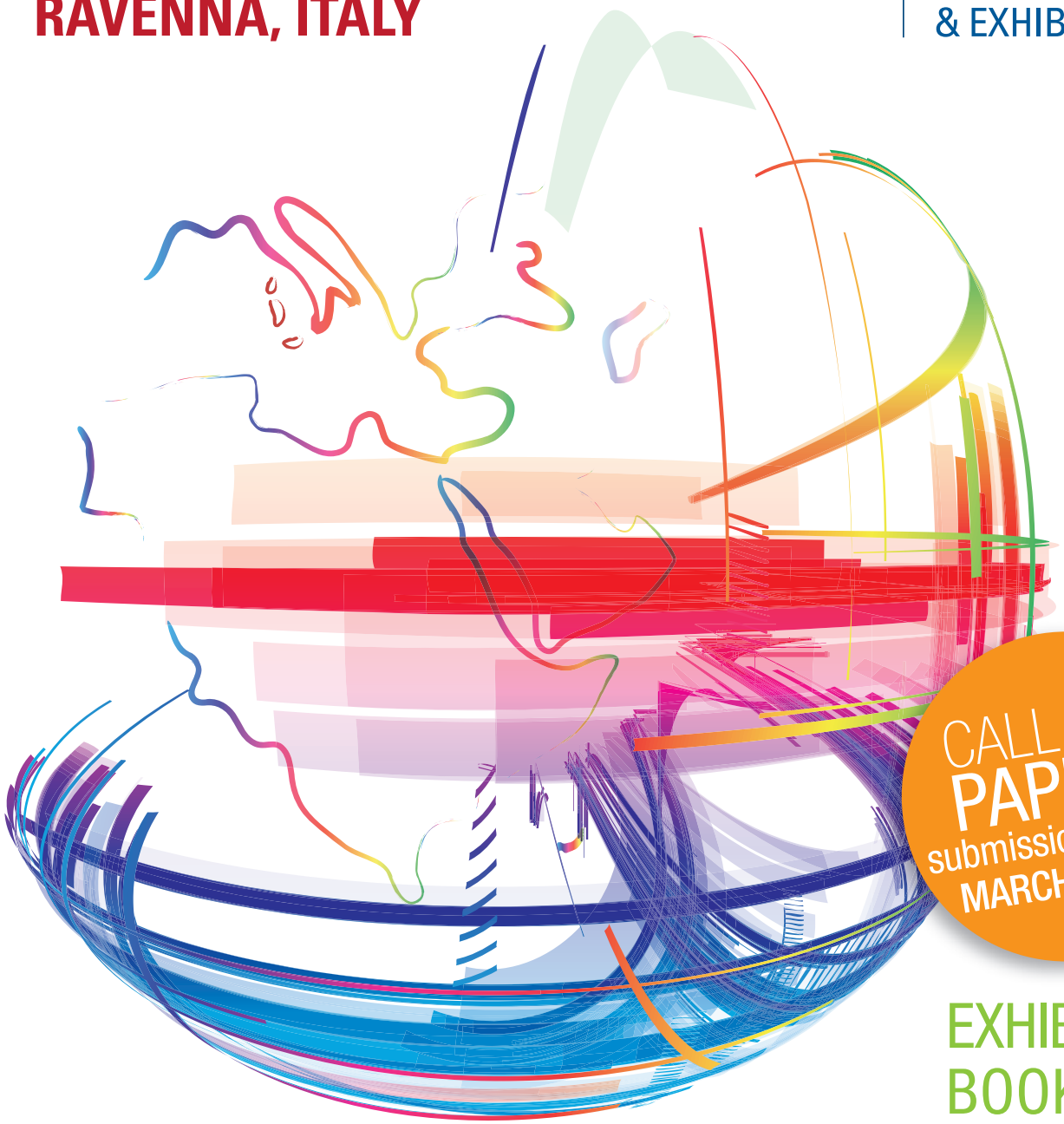

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now I can access the pumps, valves, operator screens, and the entire control system."

This theory is not a popular one with some on the operations side.

"If I make these systems separate, do I now need a separate monitor? I don't have acres of space in my offshore platform control room — not like in a refinery," Czubba says. "In today's world, everything works in an enterprise mode to make money, and the enterprise is connected from top to bottom. Nothing is going to change that, because making money is still the key.

> "You won't want logs from your computer network going to one security internet manager and logs from your video system going to another."

Now I hear the only way you can be protected is to be isolated from the network? No way. Not when we spent the last 20 years integrating everything for efficiency and economics."

"If they made that big of an investment, of course they will want remote access capability," Pollet says. "But that doesn't necessarily mean it's integrated into the DCS. But if they have integrated it, they need to make sure security controls and perimeter protections are in place around the system," he says. "There should also be controls on who can access information, as well as two-factor authentication with a user name and password unique to that person."

Those working with this day-to-day might say, "It's just video. I can't control anything or alter the operations of the rig just by watching it." But there has to be proper isolation, Pollet says.

"How have they performed security to ensure these networks are truly separate?"

FUTURE VISION

IP video will only get less expensive, more reliable, and more widely accepted in the next five years. "People are going to have constant availability and control for their networks, onsite and remotely, whenever they want," Nuth said. "Money is the only downside. But just as with increased automation and diagnostics to airplanes, which ultimately reduced crashes, we're chopping away at catastrophic events little by little. That's huge in this industry."

Pollet agrees everything will converge into IP protocols, "but you just need to make sure cyber security has been applied to keep these networks isolated and separate, based on functionality," he said.

"Your voice systems should not be talking over the same IP network as the alarm system. The video should not be on the same network as the control system. And that will require more input from cyber security. We'll see a greater deployment of firewalls to secure IP phones and video surveillance systems."

They will also want to send their logs to someone who can review them.

"You won't want logs from your computer network going to one security internet manager and logs from your video system going to another," Pollett adds.

All cyber-related logs will go to one security operations center, Pollet says. And business will grow for incident responders, cyber analysts, and security operations centers.

As far as Czubba is concerned, "you cannot operate a modern FPSO without cameras." OE REVIEW

HAZARDOUS LOCATION STANDARDS APPLY TO CAMERAS

Of course IP video equipment must be durable enough to withstand harsh conditions. Underwriter Laboratories (UL) Class 1, Division 2 (Div 2) requirements and ATEX certification are top priority.

The US National Electrical Code says hazardous material may exist in normal and abnormal conditions. Division 1 is a normal condition, and Division 2 is abnormal. Classes 1, 2, and 3 hazardous locations can fall under Division 1 or 2. In a Class 1, Div 2 area, gas and hazardous vapors could be present via leakage or system failure. In a Class 1 Div 1, area, you can assume the presence of gas and hazardous vapors at all times. "These cameras live in harsh environments with corrosive gases -- from arctic temperatures to equatorial temperatures -- minus 40 to plus 80 degrees C," says Fred Czubba, senior bsusiness development manager for oil and gas at Phoenix Contact in Middletown, Pennsylvania. "In these environments, Class 1, Div 2 is very important. The Class 1, Div 1 enclosure means totally explosion proof," Czubba says.

ATEX standards refer to the European Union's directives. ATEX directive 94/9/EC addresses equipment and instrumentation intended for use in potentially explosive atmospheres. It covers safety equipment, such as gas detectors and requirements for equipment used in explosive areas. The ATEX directive, like the US., distinguishes between two types of explosive atmospheres: gas and dust. Areas within these atmospheres are each divided into three sub-zones (comparable to the US Divisions). Zones 0, 1, and 2 refer to gas; Zones 20, 21, and 22 refer to dust.

When Gianni Viero, a vice president at VideoTec in Schio, Italy, and his team installed 37 units of stainless steel housings to monitor pipelines on an offshore platform for Arab Petroleum on the coast of Egypt's Suez Canal, he had to ensure they were intrinsically safe because of the flammable gases present. "With these stainless steel cameras, we analyze each mechanical detail to provide equipment that meets standards for reliable and resistant industrial use, especially for use in conditions that cause intense corrosion from the sea," he says. Such explosion-proof products need to be "internationally certified to meet the rigorous requirements for installation in hazardous areas with explosive risk." ▪

Numerology

232

The *Angola* FPSO project required 232 IP video cameras linked to heat sensors at each workstation. See page 144.

3 zones

To create a solid network infrastructure offshore, you could divide your network into three zones: Subnets, Virtual Local Area Networks, and Transparent Firewalls. *(Source: Belden)*

75%

of companies said they use wireless technology for communications. *(Source: Vodafone and Huawei)*

4.0

Initiatives, such as the German government's, known as Industry 4.0, have network designers working to bring offshore production and performance data to the boardroom, along with remote management. *(Source: The German Government's Federal Ministry of Education and Research)*

330 billion

Deep offshore is believed to contains an estimated 330 billion boe, which is about 7% of the world's oil and gas resources *(Source: Total).*

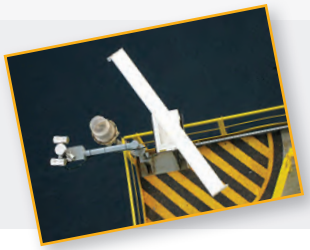
50%

About 50% of offshore platforms are at or beyond their original design life. *(Source: UK Health & Safety Executive)*

$400,000,000,000

The amount lost per year in the manufacturing automation industry, including offshore oil and gas, due to unplanned downtime from safety and security incidents. See page 134.

37



The number of stainless steel housings installed on an offshore platform for Arab Petroleum to monitor pipelines along the coast of Egypt's Suez Canal. See page 144.

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Solutions

Versabar launches new decommissioning tools

Versabar has developed innovative tools for use with its VB 10,000 heavy lift vessel. One tool, named the Claw, is a grappling device that will retrieve topsides from the seafloor; eliminating the use of hooks as lift points. Another tool, the Versacutter, is a prototype developed to sever bottom-founded objects, and their related components, without the use of divers or explosives.

Improvements in methodology have further reduced personnel involvement during decommissioning operations. Typical VB 10,000 platform decommissioning requires the platform's legs to be severed and the topside to be seafastened and transported on a barge. Preparation for the barge alone could take 3-5 hours and up to 10 personnel. Versabar remedies the inefficiency by implementing a non-welded seafastening method which will reduce exposure time, number of personnel required, and eliminate the necessity for hot work. When transporting a decommissioned platform on a barge, each leg will be bolted to a support base with a safety shield designed to protect workers from falling debris. The new method can be completed by two personnel in less than 10 minutes per leg. To further mitigate risk, drones are utilized to take aerial photos and video; minimizing offshore exposure of media personnel.

In June, a 230-ton platform was removed in 4 hours. Photo from Versabar.

According to Versabar President Jon Khachaturian, "developing solutions that allow us to improve safety and increase efficiency is what keeps us moving forward."

www.vbar.com

Belden's SPIDER switches

Belden Inc. has launched two new entry-level switches in its Hirschmann product range, SPIDER II 16TX EEC and SPIDER II 16TX/2DS-S EEC. Both SPIDER switches, which have high port densities, can be used to implement flexible networking solutions for industries including automation.

The switches have stable metal housing, can withstand extreme heat and cold (-40 to +70°C) and are approved for use in environments with a high-explosion risk. The switches, which can be mounted on a DIN rail and activated via plug-and-play functionality, are suitable for connecting to the backbone or for networking linear and tree topologies.

The 16TX/2DS-S EEC variant offers two optical dual-speed uplinks, which can be equipped with small form-factor pluggable (SFP) transceivers. These uplinks, which support Gigabit Ethernet, ensure that no bottlenecks develop even for applications with high data volumes, guaranteeing smooth communication at all times. Distances of up to 120km can be bridged with the uplinks via single or multimode fibers. The switches also meet the requirements of industrial protection class IP30.

www.belden.com

Siemens' Simatic WinCC SCADA update

The Siemens Industry Automation Division has extended the range of functions of the Simatic WinCC SCADA (Supervisory Control and Data Acquisition) software in its latest version 7.3 and added the Simatic WinCC/

WebUX v7.3 option package for mobile applications. Simatic WinCC v7.3's configuration studio now supports the central configuration of process data, messages, archiving and user management, and of texts in any languages. Configuration of the HTML5 web pages is carried out with WinCC Designer. Simatic WinCC/WebUX v7.3 is independent of any platform or browser and does not require client installation. For secure communication, https and SSL are implemented via web standards (HTML5, SVG). User management is integrated in WinCC. The licensing model is scaled according to the required functional scope and number of users, and it includes a license for WebUX access.

www.automation.siemens.com

Huntingdon Fusion Technique's welding pipe purge

Huntingdon Fusion Techniques Ltd. has manufactured a variety of different weld purging systems for pipes and tubes, where the inflatable dams can be kept outside of the heated areas. Special high-temperature-resistant gas hose material ensures that the purge dams stay inflated, firmly sealing the purged void to protect the weld throughout the whole thermal and welding cycles.

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The FSO *Ta'Kuntah*, which achieved first oil from Cantarell in August 1998. Builder Modec says it was the first FSO in the Gulf of Mexico. Image from Modec.

Pemex invests billions in Cantarell

Mexican national Pemex will invest an additional US$6 billion into its Cantarell oilfield to maintain its current production levels. The heavy oilfield is located about 80km off Ciudad del Carmen, in the Bay of Campeche.

Comprised of five fields, Cantarell was the largest offshore development in the world at the time of its discovery in 1976. The field's production, has been on a steady decline, producing 440,000b/d of crude in 2013, nearly 80% below its 2004 peak of 2.1MMb/d (US Energy Information Administration).

Pemex is not ready to give up on the aging asset. "Cantarell continues to be a good producer," Gustavo Hernández García, director general of Pemex E&P said while speaking at PECOM in April. "It's our second largest producer, nationally."

The sizable investment should produce additional 100,000b/d through secondary recovery over the course of a decade to counteract Cantarell's decline, said Miguel Angel Lozada, Pemex's Cantarell administrator. Lozada said the Akal field, in particular, would "be stabilized" under the plan. ▪

DeepFlex opens new Florida facility

DeepFlex and Offshore Inland Marine & Services, Inc. have agreed to open a new unbonded flexible pipe manufacturing and qualification testing facility in the Port of Pensacola, Florida. The industrial complex will have direct access to the existing deepwater quayside, which has potential to serve the flexible pipe markets in the Gulf of Mexico, West Africa, Europe, and Asia regions. Expected to be fully operational by 2H 2015, the plant's primary focus will be the emerging ultra-deepwater markets.

The DeepFlex Pensacola Plant will initially have a manufacturing capacity of 100 normalized km/yr of unbonded flexible pipe to serve the rapid growth of offshore developments worldwide and will composite fiber-reinforced flexible pipes to the most harsh subsea environments. The facility will have the capability of producing the complete product range of DeepFlex flexible pipes.

Rosneft files lawsuit against Sakhalin consortium

Russian national Rosneft, has filed a suit against the Gazprom-led Sakhalin Energy consortium to obtain access to the Sakhalin-2 gas pipeline. Commissioned in 2009, Sakhalin-2 is Russia's first commercial natural gas liquefaction project.

Rosneft is developing a 5mtpa LNG terminal with ExxonMobil in the Far East that was scheduled to launch in 2018.

The Sakhalin-2 project. Photo from Gazprom.

Commissioned in 2009, Sakhalin-2 is Russia's first commercial natural gas liquefaction project.Design work, FEED, and documentation was due to be completed in 2014; in April, **Rosneft CEO Igor Sechin** informed Russian Prime Minister Dmitry Medvedev that Gazprom and partner Shell had denied Rosneft access to the pipeline.

"Gazprom, being an infrastructure monopoly, is obliged to guarantee independent producers access to the transport system," Rosneft said.

Geoscientists Without Borders sponsors new project in Tanzania

Geoscientists Without Borders will sponsor a new project in Tanzania to prevent the collapse of the Lake Tanganyika fisheries. A collapse of the fisheries would be a disaster for the rapidly-growing populations in the area.

High-resolution marine geophysical survey data and analysis will be provided to develop a new conservation strategy focused on small-scale protected zones. Tanzanians working on the project will receive on-the-job training in geophysics and the principles of benthic habitat mapping to ensure sustainable results after the project's completion.

Swire Oilfield Services announces Southeast Asian expansion

To better meet increasing demand in Southeast Asia, Swire Oilfield Services has invested more than US$10 million in new rental equipment, expanding its cargo carrying unit rental fleet, and further developing operating bases in Myanmar, Malaysia, and Thailand. Development is due to be completed by the end of Q1 2014.

CGG Open Myanmar Subsurface imaging Center

Geophysical service company CGG recently inaugurated its subsurface imaging center in Yangon to service and support the anticipated growth in Myanmar's oil and gas exploration sector. The new center is the first of its kind to be opened in Myanmar by an international geoscience company. The new center is equipped with CGG's seismic processing software. A fast, dedicated network link to CGG's Singapore hub is also available for data processing.

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Faces of the Industry

By Kelli Lauletta

Faces of the Industry is a monthly series dedicated to taking readers behind the job titles to learn more about key influencers and risk takers in oil and gas. Pull the curtain back to see that it is more than just rig counts and oil prices driving our industry. It is about the spirit, creativity, curiosity and intellect of individuals at innovative companies who are writing the next chapter in industry history. This series focuses on the personal stories of featured professionals and reveals the spark that brought them into the industry, why they stay, and advice they wish to impart.

Cindy Yeilding is one of those risk takers whose curiosity and intellect has taken her from earning her BS in Geology to being named a "Legend in Exploration" by AAPG. She is a geologist (hence a "rock star"), leader, mentor, sleuth, mother, wife and inspiration to others. OilOnline recently sat down with Cindy Yeilding, BP's Vice President, Gulf of Mexico Appraisal, to learn more about her story.

How did you get interested in an oil and gas career?

I have always been fascinated by the physical world around me: a passion that was fed by my mom. My family, my neighbors and a few great teachers nurtured my interest in rocks, minerals and fossils. Undergraduate (SMU) and graduate school (UNC) exposed me to the practical applications of geoscience, and I was hooked by the merger of science and art that geologists apply in their field. I found geoscientists to be caring, collaborative and fascinating colleagues, and am thrilled to have had such a long career in such an exciting and meaningful profession.

Tell us a little about your early career stage, are there any lessons learned?

I began my career at Sohio (Standard Oil of Ohio) as a summer intern, and I was then hired as an exploration geologist and a carbonate specialist. Six months later, my team was scaled back, and I became an operations geologist. In this role, I supervised geologic activity on wells and spent a lot of time on rigs onshore and offshore, where the crews were all male. I faced a few challenges at first, but eventually recognized it is was not my being a women, but a geologist, that led the engineers to assume I did not understand the drilling process. Once I was able to build relationships with each of my team members, they began to understand how my knowledge of each well's objectives and geology could bring value to the company. Over my career, one of the lessons I have learned is that in the oil and gas industry, our brains and ability to create solutions to complex problems is what really defines us, not just our race, gender or background.

What advice would you give to those thinking about a career in oil and gas?

First, I would emphasize the great diversity of roles and experiences offered by our industry. I've studied rocks all over the world, worked on five continents and have been lucky to collaborate with some of the world's leading scientists and engineers. Next, join us if you like challenges. We integrate complex data, and our recommendations can lead to significant business investments and economic impact. Join us if you are looking for accountability. Finally, we are a high-tech industry. We are drilling wells almost six miles deep and gathering cutting-edge data in these wells. Our imaging methods are on par with the most advanced medical imaging, and we host some of the world's largest supercomputers.

Tell us about a "career high" moment for you?

A career highlight for me was being a part of the team that discovered Thunder Horse in July 1999, one of the largest deepwater producing fields in the BP portfolio. It consists of two adjacent fields ('north' and 'south') being developed together, with reservoirs in Miocene turbidite sandstones. The wells required to access the reservoir are some of the most challenging and deepest in the Gulf of Mexico. This discovery came only after a string of exploration

Cindy Yeilding

Cindy Yeilding earned her MSc from the University of North Carolina after receiving a BS in Geology from Southern Methodist University. She has worked as an exploration, production, appraisal and well-site operations geoscientist and is currently BP's Vice President, Gulf of Mexico Appraisal. Her most recent roles include Chief Geoscientist for the Gulf of Mexico, Global Geoscience Technology and R&D Manager for BP, and Exploration Leadership positions in the US and Venezuela.

Cindy has developed and led short courses and geological field seminars, chaired numerous technical sessions and presented many technical talks. She has served as an AAPG (American Association of Petroleum Geologists) Distinguished Lecturer and was named a "Legend in Exploration" by AAPG in 2003. Cindy is also a member of the Offshore Technology Conference (OTC) Board of Directors.

failures caused us to completely rethink our approach to the geology of the Gulf of Mexico: demonstrating that challenging conventional wisdom or dogma can lead to great outcomes.

One issue that comes up frequently in this industry is the "burnout" rate. What types of strategies would you recommend to help others with work/life integration?

Work on its own can be challenging, and it can become very complex when you're trying to balance it with family, relationships and other real-world activities. Weaving a sense of humor into your work can help relieve pressure, and good friends with generous listening skills can help you keep work challenges in perspective. I've found that honest conversations with leadership and colleagues about prioritization and deadlines can really help diffuse the stress: not everything always has to be done, at once. I've also seen flexible work schedules and part-time work applied really well: often best enabled by clarity on deliverables and expectations up front.

To be candid, with two young children and a dual career, lots of things fall through the cracks at home. I've got very few hobbies and meals are often "assembled" rather than "created." Truthfully, I am a strong believer in coffee: I definitely have a frequent-buyer card at Starbucks!

What would surprise most people about your job?

One of the things that may surprise people about geology is that you are a sleuth. You are using clues from the earth, outcrops and the subsurface to help you put together your best story for how the earth's rocks were laid down and their history. I approach my job a bit differently than other people; I try to look at the biggest picture on the widest scale possible and then go out and find people who will have insights that feed into that picture. Their ideas come together to help me solve the issue or problem.

What trends do you see on the horizon in the oil and gas industry?

We face continuous challenges: economic challenge, political changes and scientific breakthroughs in our quest to safely provide heat, light, mobility and jobs for the world. It never gets simpler; yet, oil and gas will remain a significant part of the global energy mix for the world for decades to come. Great science and engineering will always be in demand in this industry. OE

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

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

Spotlight

By Anthony Onukwu

The SPE 'guardian angel'

SPE Aberdeen chairman Anthony Onukwu reflects on society's impact on the North Sea oil and gas industry as the Aberdeen section celebrates its 40th anniversary.

Anthony Onukwu, SPE Aberdeen Chairman.

Having started out with the Society of Petroleum Engineers (SPE) during my time as a student at the Robert Gordon University in Aberdeen, it has filled me with great pride to chair the Aberdeen Section for the last two years.

SPE Aberdeen was established in 1974, three years after the first Offshore Europe was held in Great Yarmouth in 1971, under the name of Oiltech.Since then, the workforce that has amassed in this area is diverse. The 2500-strong SPE Aberdeen membership comprises of different age groups, nationalities, backgrounds, interests, and genders. Currently, our board has two female committee chairs, ages ranging from 29 to 60, eight nationalities, Masters and PhD holders, Distinguished Lecturers, and a number of industry professionals, both technical and non-technical.

SPE Aberdeen has spent the last 40 years establishing events such as the European Artificial Lift Forum (EuALF) to address problems such as artificial lift for horizontal wells. This is a particularly challenging topic in the oil and gas industry at the moment. Techniques for horizontal wells are mostly based upon methods established in vertical wells, although often without acknowledging the fundamental differences. The merits and demerits of various techniques in horizontal wells are not well-established and modeling tools for comparing the performance of different approaches are not there yet for horizontal wells.

By encouraging the upstream oil and gas industry to engage in an open dialogue and share breakthroughs and lessons learned in niche sectors, such as artificial lift, SPE has made a significant contribution to driving forward major industry developments.

In my own professional life, SPE has been somewhat of a guardian angel, with me along every step of my career journey. During my time as chairman, one of my proudest moments was when our section won the SPE International President's Award for Section Excellence for the fourth consecutive year and the Innovation award for the first time.

On a personal level, I received the SPE North Sea Regional Outstanding Young Member Award in 2008 and the SPE International Award for Young Member Contribution to the Society and Petroleum Industry in 2009. To be nominated and voted for by my peers was an incredible feeling.

More broadly, this is a very special year for SPE Aberdeen and we have reached this landmark thanks to the support of the North East Scotland oil and gas community but, more importantly, the support of our members, who are the core of the SPE. We were here shortly before the first drop of oil was extracted from the North Sea forty years ago and we hope to be here when the last drop of oil will come out of it. OE

***Anthony Onukwu** joined SPE Aberdeen in 2002 as a student member and has been a chair of the Young Professionals and Membership committees, as well as a member of steering committees responsible for organizing events in Aberdeen, such as the Sand Management Forum and European Artificial Lift Forum. Internationally, he has been the editor-in-chief of SPE's The Way Ahead journal. He became the chairman of the Aberdeen Section in 2012.*

Onukwu worked as a project engineer at Vetco Gray (now GE Oil & Gas) before going on to work for Eclipse Petroleum Technology and then ITF, where he worked with a number of exploration and production companies on projects in the North Sea, Gulf Coast, West Africa, and Southeast Asia. He is currently a production technologist at Shell UK, responsible for a brownfield well and reservoir management and well abandonment activities.

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OHH raises money for those working in the oil and gas industry who have fallen on hard times. In the last 10 years, we have raised and donated more than $2.5 million. Thanks to golfers and bidders like you, we are able to make a difference and change the lives of those in need.

So put on your boots and blazers and get ready for a night of fun. Visit the OHH website at **oilfieldhelpinghands.org** and sign up for the gala, become a sponsor or volunteer. You do not have to play in the tournament to attend the gala.

Numerology

US$50 million

The amount invested by BOEM and others towards marine noise-related research and protected species. See p. 16.

455

The number of structures reefed to date in the Gulf of Mexico. See p. 80.

50%

of survey work awarded through tenders was for marine broadband seismic. See p. 42.

300mm

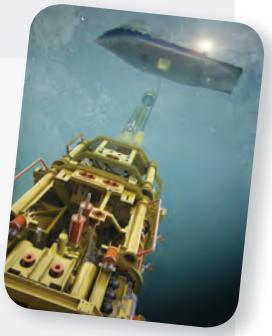
The smallest scratch that the Crab Tool, an in-situ bolt inspection tool developed by Ativatec in partnership with Petrobras, can detect. See p. 38.

200,000ton

Weight of the Berkut platform in the Sea of Okhotsk, 25km off Sakhalin Island. See p. 20.

350°F

The reservoir temperature found at Total E&P UK's Elgin Franklin development in the North Sea. See p. 48.



10,000psi

The pressure rating of FMC Technologies' new RLWI stack. See p. 28.

3.8GW

The offshore wind transmission capacity being installed by TenneT offshore northern Europe. See p. 110.

14,000 b/d

Current production of two Weatherford subsea wells installed in the North Sea's Jette Field. **See p. 58.**

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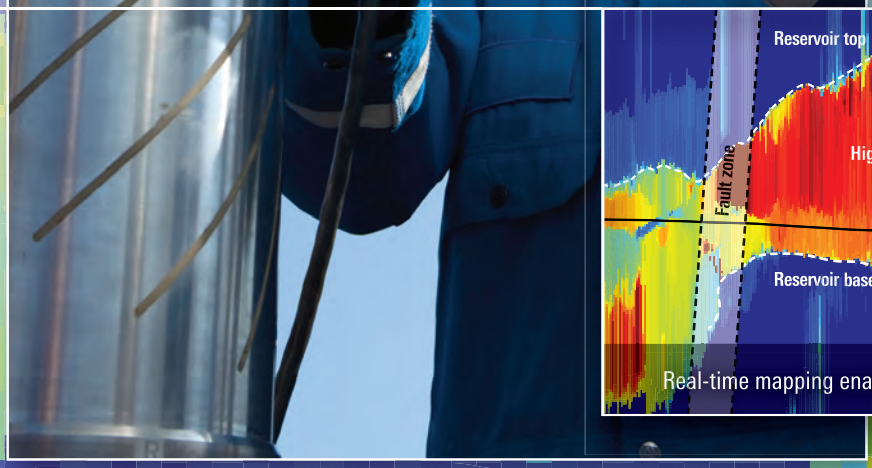

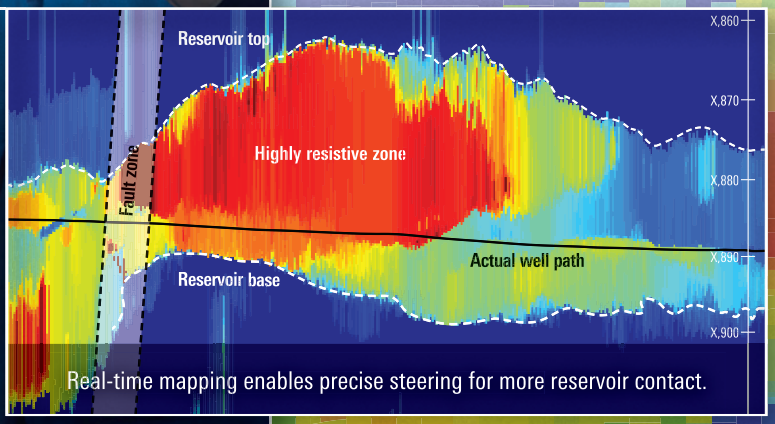

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