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Offshore Engineer • November 2014


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completion design.

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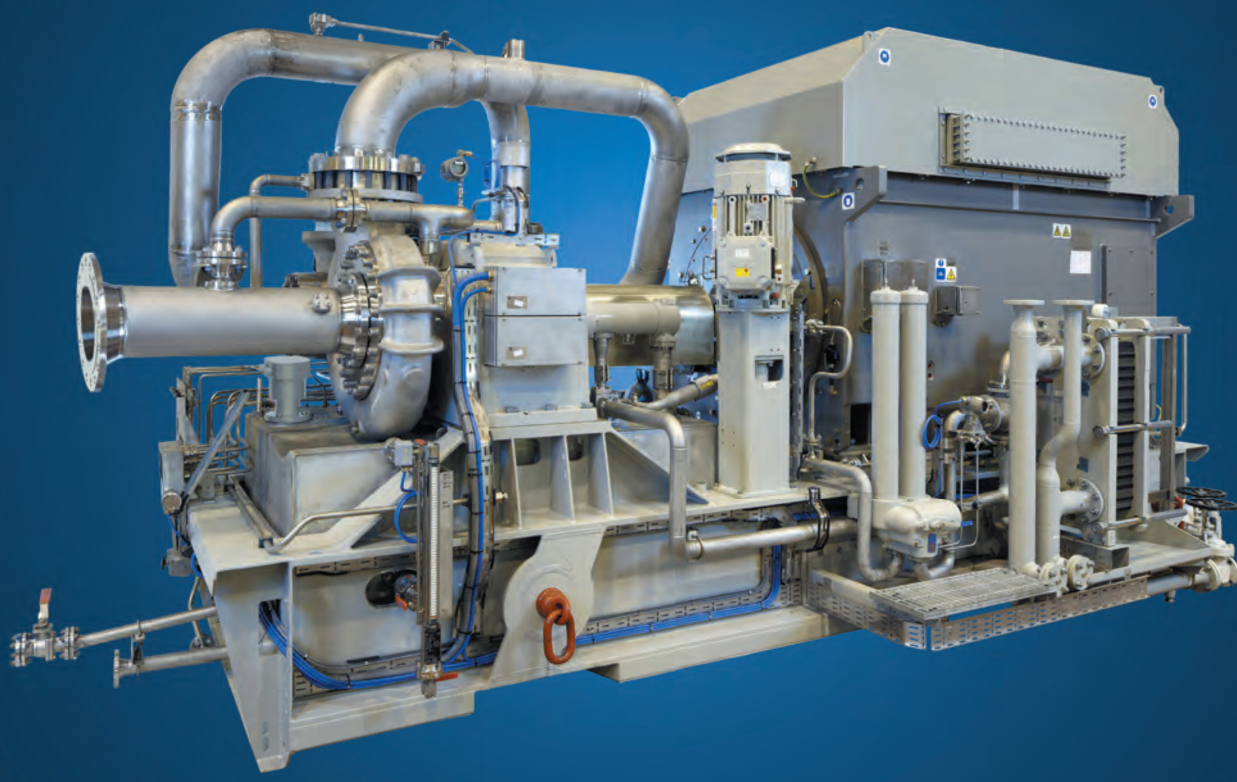
Feature Focus

Asset Integrity Management

ON THE COVER

New destinations. The gravity-base structure for the ExxonMobil's Hebron project was towed from drydock to the project's construction site, Bull Arm, in July. Located off Newfoundland and Labrador, the 120m-tall structure has a production capacity of 150,000b/d and will operate in an average water depth of 93m. Photo from ExxonMobil Canada Properties.



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PUBLISHING & MARKETING

Chairman
Shaun Wymes
shaunw@atcomedia.com

President/Publisher
Brion Palmer
bpalmer@atcomedia.com

Associate Publisher
Neil Levett
neil@aladltd.co.uk

EDITORIAL

Editor
Nina Rach
nrach@atcomedia.com

Managing Editor
Audrey Leon
aleon@atcomedia.com

European Editor
Elaine Maslin
emaslin@atcomedia.com

Associate Editor
Sarah Parker Musarra
smusarra@atcomedia.com

Web Editor
Melissa Sustaita
msustaita@atcomedia.com

Contributing Editors
Kelli Lauletta, Claudio Paschoa, Eugene Gerden

Editorial Intern
Jerry Lee

ART AND PRODUCTION
Bonnie James
Marlin Bowman

CONFERENCES & EVENTS

Events Coordinator
Jennifer Granda
jgranda@atcomedia.com

Exhibition/Sponsorship Sales
Gisset Capriles
gcapriles@atcomedia.com

PRINT
Quad Graphics, West Allis, Wisconsin, USA

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Departments & Columns

"Which is more important: the human or technological element?"


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Online Exclusive

Service under sanction

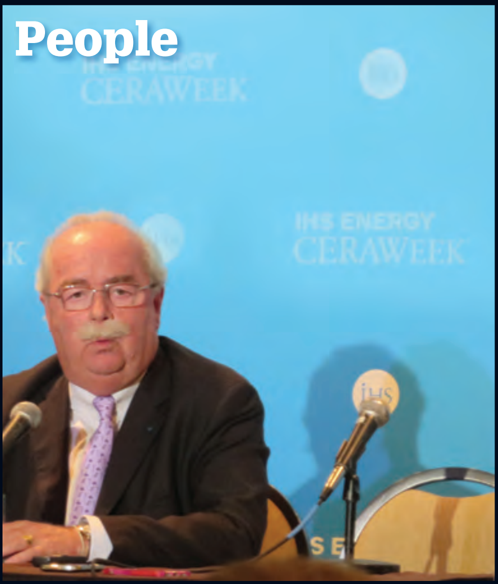
Sarah Parker Musarra looks deeper into how western sanctions are affecting the service companies that do business offshore Russia. Photo from Rosneft.

What's Trending

Ups and downs

- BOEM announces first 2015 GOM lease sale
- Petrobras starts Iracema production
- Afren dismisses top executives
- Petronas buys Statoil's Shah Deniz stake

People



Voices

Integrity matters. When it comes to asset integrity management, OE asked:

Which is more important: the human or technological element?

You can't run a successful asset integrity program without good technology, especially for managing data. But no software or other technology can run an asset integrity program without good people with the right mindset to use the tools. So good people with the right attitude are most important, then you need to give them good tools so they can do their job.

Pierre de Livois
Senior Vice President, Bureau Veritas Marine & Offshore Division

The right people following the right processes with the right tools - should be the answer. The human factor is the driving influence, leading the other two components; the processes and technology will follow when the right people are in place.

The leading cause of many incidents is due to the "human factor." Human error is the result of a general lack of competence and/or not following procedures. Whether this is due to training or perhaps a lack of integrity, the consequences are great. Technology becomes fundamental in decreasing and in some cases diminishing human error.

Martha Sandia
Vice President of North American & Caribbean Stork Technical Services

Operators are spending billions of dollars on projects that must maintain uptimes of 24/7/365 for 25 years. The products that go into these projects – these human-made assets – must withstand the longevity and environmental pressures for which they're designed. The importance of asset integrity relies evenly on the engineering intelligence and skills of the people who are part of the system design and manufacturing process throughout the supply chain, and the resulting high quality and technologically complex product; therefore heavy significance is weighted evenly. Proper, disciplined system engineering needs to view these two elements as a horizontal and vertically integrated scope of work.

Pat Herbert
Chairman and CEO, JDR Cable Systems

The combination of the human and technological interface has never been more critical and closely related than within asset integrity management. Technology has reached a point of efficiency where engineering personnel can closely monitor corrosion and equipment's fitness for designed use without having to destructively test any component. Utilizing specialty programs to keep clear and concise data allow operators the opportunity to identify trends, make corrections and avoid equipment failures. With that in mind, the placement of experts and the training of personnel to identify problematic components and address issues are a central focus for our business and our industry.

Stephanie Crochet
President/CEO, AFS Petrologix

While both elements are crucial in ensuring asset integrity, only technology can deliver the wide scope and great detail of evaluation that needs to be completed to gain a holistic understanding of the integrity of all assets, from the wells to the export pipeline. Technology allows the integration of detailed data from multiple sources and departments with automated analysis and consistent data interpretation. And only technology can deliver realistic benchmarking of performance across global operations and organizations to identify scope for performance improvement.

Liane Smith
Founder and Managing Director Wood Group Intetech

Both the human and technological components are vitally important to achieve effective asset management. With the onslaught of regulations today, compliance with health, safety and environmental issues are driving forces behind asset integrity. Additionally, equipment inspections and maintenance are crucial to ensure equipment integrity and avoid unscheduled downtime of any given asset. The collection and the management of data greatly improve the chance of attaining effective asset management. Technology is the key element for gathering and measuring data while humans are the key element to managing the data. You can't effectively manage those things that you can't measure; therefore, there is an equal need for both humans and technology.

Jeffery Svendson
President and CEO, Advanced Logistics

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

Colloquy

Offshore helicopters
(On a rotary wing and a prayer)

Offshore activity drives the global market for oil and gas-related offshore helicopter services, which is estimated to be worth US$24 billion over the next five years, 2014-2018. Companies that provide rotary wing ferry services to and from rigs and vessels have been expanding fleets and ordering new aircraft. A few months ago, investment bank Barclays predicted that the oil and gas industry will need 300 new helicopters between now and 2020.

New models have been developed with greater range to support operations further offshore. These include the AgustaWestland AW189, Bell 525, Airbus EC175, and new Russian Mi-38, which will begin production in 2015.

2013 global helicopter sales
units >1300kg

Company	# units delivered
Airbus Helicopters	497
Bell Helicopter	291
Russian Helicopters	275
Sikorsky Aircraft	240
AgustaWestland	230
Boeing	81

A recent offshore civil helicopter market report expects increasing growth in Asia, Australasia, Africa, and Latin America and notes that 60% of service expenditures are for medium helicopters. New-generation models, such as EC175 and AW189, have advanced safety systems for offshore work.

Most helicopters for the oil and gas industry are built by four rotorcraft manufacturers:

- Anglo-Italian AgustaWestland, a subsidiary of Finmeccanica SpA.
- Airbus Helicopters, a division of Airbus Group NV, formerly Eurocopter Group.
- Texas-based Bell Helicopter, a division of Textron Inc.
- Connecticut-based Sikorsky, a United Technologies Corp. company.

A major manufacturer of light civil helicopters is Robinson Helicopter Co., based at Zamperini Field in Torrance, California. The company has produced more than 10,000 aircraft since 1979, and was the top manufacturer worldwide in 2013, selling 523 light helicopters.

Vertolyot

Another very large manufacturer, Russian Helicopters JSC, was established in 2007 as part of state corporation Rostec. It is now the sole Russian rotorcraft designer and manufacturer, with headquarters in Moscow. There are more than 8500 Russian helicopters currently operating, representing 14% of the world's fleet, but they are not as widely distributed as the other manufacturers.

"Market demand for medium and heavy commercial helicopters is largely driven by operators servicing the oil and gas industry," and these comprise 76% of Russia's fleet, according to the company's magazine (May 2014).

Russian Helicopters is opening pilot service centers in key markets, including India, China, and Latin America.

Operators

CHC Helicopters, based in Richmond, British Columbia and part of CHC Group Ltd., says it is the largest commercial helicopter services company in the world, and recently ordered 33 more new helicopters. CHC subsidiary Heli-One, headquartered in Delta, British Columbia, provides international maintenance, repair and overhaul (MRO) operations, as well as offshore transportation.

Houston-based Bristow Group says it controls about one-third of the global fleet that services the oil and gas industry. Bristow Group said it is investing more than $1 billion in 47 new helicopters, "more in one year than in the previous 30 months combined," according to Jonathan Baliff, who became CEO in July.

Houston's Era Group Inc. runs Era Helicopters LLC, which primarily serves the oil and gas industry. The company is focused on the Gulf of Mexico and Alaska, but also operates in China, India, and Australia, among other countries. Sten L. Gustafson resigned as CEO in August and the Era board named Christopher S. Bradshaw, Era's EVP and CFO, as acting CEO, effective 29 August 2014. Era is acquiring 20 more helicopters, including four Sikorsky S92 heavy helicopters for $129 million.

Flight simulators

The boom is also bringing a surge of new flight simulation training devices, as operators try to improve safety.

Steve Phillips, VP communications for FlightSafety International, said "For the most part, the oil and gas community requires helicopter operators who provide them services to adopt not only simulation training but also safety management system programs, prudent regulations and improved avionics to reduce accidents." **OE**

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AtComedia
1635 W. Alabama
Houston, Texas 77006-4101, USA
Tel: +1-713-529-1616 | Fax: +1-713-523-2339
email: info@atcomedia.com

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Iartin Belshaw, technical director, Semco Maritime

ThoughtStream

Addressing the challenges of obsolescence

Obsolescence is not a new issue for the offshore energy industry, however, it remains an insidious creeping plague, which hides in the wake of new and changing technologies to take everyone by surprise around 10 years into the system life cycle.

There are many reasons why obsolescence is becoming an increasingly significant issue for the offshore oil and gas industry and perhaps the most obvious is the prevalence of extended life operations. Many assets remain in production for over 25 years and their associated automation and control systems continue to be used well beyond their anticipated life expectancy. More than half of oil and gas installations in the North Sea fall into this category, and only about 15% have been decommissioned thus far.

Meanwhile, technology marches on; process functionality changes; the availability of spare parts declines, and eventually manufacturers and third parties are unable to provide technical support. This problem is further compounded as systems become subject to new demands and changes in industry legislation; products so affected by such events are often referred to as "mature discontinued." In the worst-case scenario, operators may only become aware of any issues following a component's failure. With the prospect of a fix weeks, or possibly even months, away the unpalatable result can be a significant unplanned downtime event.

So what can be done to counteract this "creeping plague"? With activity in the North Sea expected to continue until at least 2050, there is a clear requirement for those in the industry to take a proactive and systematic approach to the related issues of obsolescence and extended life operations.

Over 50% of assets now exceed their design life, so a robust system of obsolescence assessment is a necessity rather than an option. Operators will forget at their peril that equipment obsolescence, whether in relation to sophisticated control systems or regular instrumented systems, presents significant risks to production, safety and the environment.

The need for operators to determine, quantify and manage the risks associated with obsolescence is therefore paramount, as recognized by the UK Health and Safety Executive (HSE) in its report to Oil & Gas UK earlier this year (OE: August 2014). Following a three-year investigative program, the HSE report recommended that the industry develops a corporate culture which embeds an aging life extension (ALE) philosophy into asset integrity management for the long-term future.

"Over 50% of assets now exceed their design life, so a robust system of obsolescence assessment is a necessity rather than an option."

An important part of this process will be the establishment of comprehensive procedures and systems that allow for continuous monitoring of assets and anticipation of issues so that these can be managed proactively.

A robust approach to obsolescence assessment involves detailed design studies, offshore site surveys and reporting. The results of these exercises enable the production of an accurate and comprehensive "cabinet-rack-slot" equipment inventory. In order for this inventory to be "intelligent," its contents are then subject to further assessment, using established methodologies and weighting factors to determine vulnerability, impact and risk. Sophisticated database systems are now available for the recording, analysis and storage of such data.

Having gained a clear and realistic picture of their assets and associated systems, operators can then look at proactive tactics and strategies for removing or mitigating any obsolescence risks. These may range from improving supplier relationships and spare parts management through to wholesale or systematic migration but in the most severe cases complete system replacement may be required.

A robust and intelligent system of obsolescence assessment should, therefore, not only identify risks, but also suggest solutions in relation to mitigation, migration or replacement on the basis of practicality, cost or both. Those who are nervous about disruption to everyday activities should note that both obsolescence assessments and system migrations can be carried out with minimal impact on normal day-to-day operations. Furthermore, when the value of such exercises is considered in terms of accident prevention and safeguarding against future costly disruptions, there can be no question as to the validity of this investment. OE

Martin Belshaw *is technical director at Semco Maritime. A chartered engineer and current chairman of the north of Scotland section of the Institute of Measurement & Control, he has more than 30 years' experience designing and managing computer-based process control systems, networks and system integration projects in the energy sector.*

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Global Briefs

A Cardona on track

Louisiana-based Stone Energy is ahead of schedule on the deepwater Cardona development project in the US Gulf of Mexico. The Cardona South well (MC 29 #4), in Mississippi Canyon 29, is expected to begin initial production by December. Stone says production will reach an estimated 12,000boe/d for both the MC 29 #5 and MC 29 #4 wells. Stone Energy operates both Cardona wells with 65% interest.

B TGS surveys GOM

TGS will continue its Explorer series seismic acquisition program with Panfilo 3D, which will add 11,500sq km to TGS' multi-client library in the Lund and Henderson Central Gulf of Mexico protraction areas. Acquisition will commence in 4Q 2014 with the M/V *Polarcus Adira* towing 10km streamers to image regional stratigraphy and deep basin structures. Data will be available in late 2015.

C Peruvian seismic

Peru's Perupetro contracted Spectrum for 2D seismic work prior to the country's international bid round on 12 December. Spectrum will reprocess approximately 13,000km of 2D multi-client regional seismic data covering the lease sale blocks.

The data will be available in October. In April, Peru's government said that six coastal blocks in three of Peru's 18 sedimentary basins would be available through the round. Spectrum said that the round might include more offshore blocks, noting that between six and nine would be offered.

D Noble resumes Falklands drilling

Noble Energy will resume exploratory drilling in the Falkland Islands next year after acquiring and reviewing extensive 3D seismic of its 10 million acre-position. Noble Energy said Humpback, within the Fitzroy sub-basin of the southern area license, would be drilled first. In June, Ocean Rig announced a 260-day contract for its *Eirik Raude* drilling rig scheduled to begin off the Falkland Islands 1Q 2015.

E Prospector to survey off Guyana

Prospector PTE will conduct a 3116.74sq km 3D seismic survey on the Demerara Block, offshore Guyana, for CGX Energy. The Demerara Block spans 3953sq km in the Guyana-Suriname basin. Prospector will use its 12-streamer 3D seismic vessel, R/V *BGP Prospector.* The total value of the seismic survey, which will complete in 60 days following mobilization, is US$17.9 million.

F Faroe ventures off Ireland

Faroe Petroleum made its first move into the Irish offshore by picking up three new, two-year licensing options (14/1, 14/2 and 14/3) on the southern margin of the North Celtic Sea basin. A work program, agreed with Irish authorities, involves reprocessing and interpreting 2D seismic data for each license and the preparing supporting geological studies. The licenses are in 80-110m water and together cover 3458sq km, all within 75km off the southern coast of Ireland.

G Centrica spuds Ivory well

Centrica Energy began drilling on the Ivory prospect in production license 528 in the Norwegian Sea. The *West Navigator* drillship will drill exploration well 6707/10-3 S, 20km northeast of the Statoil-operated Aasta Hansteen development, which is due on stream in 2017. Partner Rocksource estimates the Ivory prospect to have 280-1280 billion standard cu ft (50-230MMboe) unrisked, gross prospective resources in the primary target. Centrica operates Ivory with 40%.

H RWE delays Zidane

Germany's RWE Dea is will not submit a plan for development and operation (PDO) for the Norwegian Sea Zidane development as planned, the firm said, citing the need to improve the project's economics.

Zidane, discovered in 2010, is in production license 435, about 15km northwest of the Heidrun field. The plan was to develop the field with a subsea template and a tie-in to the Heidrun tension leg platform platform, where the gas would be processed and exported further through the Polarled pipeline.

I Leviathan development plan submitted

The partnership behind the Leviathan field off Israel submitted a US$6.5 billion initial development plan to Israel's Ministry of National Infrastructures, Energy and Water Resources. About 130km offshore Israel, in around 1600m water depth, the Leviathan field is one of the largest offshore discoveries in the past decade, and Noble Energy's largest discovery to date. In July, Netherland Sewall & Associates put the high reserves' estimate up to just under 22Tcf of natural gas. The first stage of development will include an FPSO unit with 16Bcm/y gas production capacity.

J JV picks up Egyptian licenses

Eni and Petroceltic International's joint venture with Edison International

picked up new exploration licenses in Egypt's 2013 international licensing bid rounds. Eni was awarded three, two of which (8 and 9) are in the deepwater Mediterranean Sea near the Cypriot boundary. Operatorship of Block 8 will be split with BP. Block 9 covers 5105sq km and is in 2100-2800m water depth. Block 8 covers 4565sq km in 2000-2500m water depths.

Petroceltic's joint venture was awarded the North Port Fouad Block (Block 7) offshore the Nile Delta to the north of, and immediately adjacent to, the North Thekah Block, which was awarded to a Petroceltic/Edison joint venture in 2013.

Meanwhile, Egypt paid off US$1.5 billion of its debt to foreign oil and gas companies, the country's petroleum minister announced. BG Group confirmed it had been paid US$350 million.

K Drilling delayed

ExxonMobil CEO Rex Tillerson said that the Ebola virus has disrupted plans to drill the Mesurado-1 wildcat well, in block LB-13, offshore Liberia, due to a lack of expatriates in the country. About 18mi off Liberia's central coast, the block covers 2500sq km area in 75-3000m water depth. Seismic data identified a deepwater Turonian to Lower Campanian turbidite channel/fan complex in the block with strong similarities to other turbidite sand reservoir oil fields offshore Angola, partner Canadian Overseas Petroleum said. The company put p90 gross reserves at approximately 1.7 billion bbl.

L Nigeria prospects increase

The recoverable resource estimate for CAMAC Energy's four offshore Nigeria prospects in oil mining leases (OMLs) 120 and 121 has been increased from 537MMbbl to 2.37 billion bbl, according to an independent assessment conducted by DeGolyer and MacNaughton (D&M). P50 unrisked recoverable oil resources for the Ereng prospect, the largest of the four, are estimated at 1.585 billion bbl. P50 unrisked recoverable gas resources for Ereng are estimated at 2.086Tcf. CAMAC says the first exploration well is planned for in 1H 2015. The wells will target the Miocene formation, which has proven to be a prolific oil production layer in deepwater Nigeria.

M Cairn strikes Senegal oil

Cairn Energy and its Senegalese partners struck oil on the deepwater FAN-1 well, drilled using the semisubmersible *Cajun Express* to 4927m target depth in 1427m water depth, 100km offshore Senegal. The well discovered 29m of net oil bearing reservoir in Cretaceous sandstones. No water contact was encountered in a gross oil bearing interval of more than 500m. FAN-1 was the first well drilled in deep water offshore Senegal and was the first well drilled in the country's offshore waters for more than 20 years, said Australia-based partner Far Ltd.

N BG ups Tanzania find

BG Group is now sitting on more than 17Tcf of gas offshore Tanzania after its latest discoveries in the Kamba-1 well in Block 4. The well, drilled by the *Deepsea Metro I* drillship in 1379m water, found 1.03Tcf in the Kamba and Fulusi prospects, said partner Ophir Energy. The discoveries, plus recent volume updates on earlier discoveries in Blocks 1, 3 and 4, which BG operates with Ophir, increases Ophir's estimate of the total mean (2C) recoverable resources on the blocks to 17.1Tcf. The Kamba-1 discovery is BG and Ophir's 16th consecutive discovery well in Blocks 1, 3 and 4, offshore Tanzania. It is also BG's final well in its current drilling campaign in partnership with Ophir.

O Mubadala spuds two off Thailand

Abu Dhabi-based Mubadala Petroleum spudded two wells on the Manora field off Thailand. Drilled with Atwood Oceanics' jackup Atwood Orca, the MNA-04 and MNA-05 wells are the fourth and fifth wells, respectively, in a planned 15 developmental well campaign set to end 1Q 2015. Joint venture partner Tap Oil said that wells MNA-04 and MNA-05 will be drilled to final target depths of 3430m and 1934m measured depth, respectively. MNA-04 is the first of five planned water injector wells. The remaining 10 wells are planned to be producers. As part of the field's development plan, a moored, site-specific FSO will also serve as an accommodation hub.

P Frontier to drill in Calauit

Malaysia's UMW Offshore Drilling and Frontier Oil Corp. signed a US$20 million agreement for Frontier to drill two development wells in the Calauit oil field off northwest Palawan in the Philippines. The contract is for a 120-day period with an option to extend for an additional 180 days. Drilling is scheduled to take place 1Q 2015. Kristoffer Fellowes, Frontier's president, says the company has the flexibility to use the UMW NAGA 7 jackup rig in other areas within the Philippines, making it an extremely valuable contract to the company.

Q Lundin adds Malaysia stake

Norway's Lundin Petroleum will acquire operatorship and 50% interest from Petronas Carigali in PM328, offshore Malaysia. In the first 18 months of the three-year production sharing contract (PSC), Lundin Malaysia will conduct 3D seismic of 600sq km in PM328. Lundin Malaysia will then have the option of drilling one well in the remaining 18 months, or choose to give back its interest to Petronas, penalty-free. PM328 covers 5600sq km northeast of the Lundin-operated PM307.

R Roc begins China campaign

CNOOC began drilling at the WZ12-10-1 exploration well in the Beibu Gulf Block 22/12, offshore China, said partner Roc Oil. The well is 4.7km east-northeast from Roc's existing Beibu 12-8W facilities and is in about 35m water depth. Drilling began on 10 September using the jackup rig HYSY 935. Total depth is planned at 1539m. WZ12-10-1, the first of two exploration wells in Beibu Gulf Block 22/12, is targeting the T42 and Weizhou West formations. CNOOC operates Block 22/12 with a 51% interest.

S Rosneft hails Arctic find

Russia's Rosneft and partner ExxonMobil made an oil discovery on the Universitetskaya-1 well, in the East-Prinovozemelskiy-1 license in the Kara Sea. The well was drilled in one and a half months, amid a clamor over US and EU sanctions aimed at Russia over its involvement in the Ukrainian crisis. The discovery, named Pobeda ("victory" in Russian), contained 338 billion cu m of gas and more than 100 million tonnes of oil, said Rosneft. Drilling started 9 August, in 81m water depth, 230km off Russia, using North Atlantic Drilling's *West Alpha* semi-submersible. ExxonMobil had been given an extension by the US Treasury Department to "wind down" operations relating to the Kara Sea well.

T Apache passes on farm-in

Apache Northwest elected not to exercise its option to farm-in to the AC/P50 and AC/P51 exploration permits, offshore Australia, with operator MEO. Under an agreement signed in June, Apache had until 30th September 2014 to elect to acquire a 70% interest in the permits at their renewal, scheduled for April 2015. MEO CEO Jürgen Hendrich said the company remains receptive to other potential farm-in offers. MEO holds 100% interest in AC/P50 and AC/P51, offshore northwest coast of Australia, in the Vulcan sub-basin. The permits, awarded in 2009, cover 1943.6sq km. ■

Contract Briefs

Pemex partners up

Since enacting Mexico's energy reform, Pemex has signed MOUs with several companies including Malaysia' Petronas, Argentina's YPF, Australia's BHP Biliton, and ExxonMobil in recent months. The MOU between Petronas and YPF calls for sharing experiences and best practices in exploration and production. The BHP Billiton MOU calls for exchanging technical knowledge and expertise related to deepwater drilling. The ExxonMobil agreement will see both firms sharing upstream and downstream business opportunities. These new agreements highlight Pemex's desire to attract new technology, capital, and partnerships.

Teledyne picks up Kaombo contract

California-based Teledyne Technologies' Oil & Gas group won a contract from Aker Solutions to provide materials and engineering support covering subsea electrical and optical wet-mate interconnects for Total's Kaombo development offshore Angola. Shipments are expected to start 4Q 2014.

Ocean Installer catches SURF

Ocean Installer won a contract for SURF support work in Brazil from Saipem. The contract is valued at US$50 million, with options to extend.

Ocean Installer will support Saipem with their installation of multiple steel catenary lazy wave risers, free standing hybrid risers and export pipelines for the Iracema and pre-salt projects in the Santos Basin for Petrobras. The scope of work includes a wide range of services including survey, TDP monitoring, metrology, installation aid deployment, recovery and pre-commissioning.

Subsea 7 to support Baobab

CNR International chose Subsea 7 to support its Baobab Field Phase III development in the Ivory Coast. The work scope covers spool and umbilicals installation. The main offshore installation phase expected to be executed using Subsea 7's *Seven Pacific* starting 2Q 2015. Onshore project management and engineering will be carried out from Subsea 7's Paris office.

Saipem scoops EPCI work

Saipem won two contracts, totaling US$750 million, in the Gulf of Mexico. The firm will be responsible EPCI work at the Lakach field, 98km southeast of Veracruz and 131km northwest of Coatzacoalcos, in 850-1200m water. The work includes connecting the offshore field with the onshore gas conditioning plant, with two 73km-long, 18-in. diameter gas flowlines, and a 50km-long main umbilical. Saipem will develop the subsea, umbilicals, risers and flowlines facilities, including trees and control system installation. The project will be completed by the end of 2017.

Additionally, Protexas awarded Saipem a transport and installation contract for the installation of offshore structures, including two platform decks of around 3000-tonne each, in Mexico's Bay of Campeche.

Sevan wins Bream FEED

Sevan Marine is will conduct FEED for the hull and marine systems of a cylindrical FPSO for Premier Oil's Bream oil field in the Norwegian North Sea. The Bream field will have an FPSO with subsea production and water injection wells. The nearby Mackerel development will be a 17km subsea tie-back to the Bream facilities. Premier, holds 50% interest in Bream. ■

Frosty relations

How much does Russia's oil and gas industry stand to lose in light of increasing Western sanctions? Sarah Parker Musarra reports.

Despite a tentative ceasefire in place, on 12 September, the EU and the US enacted another round of sanctions against Russia under Executive Order 13662 for the country's involvement in the Ukrainian crisis. Previous sanctions targeted those whom the US Department of the Treasury identified as members of Russian Federation President Vladimir Putin's inner circle, including Rosneft President and Chairman Igor Sechin.

The September sanctions, however, had a different target in its sights altogether: These aimed to place a chokehold on Russian offshore exploration, and, according to a statement issued by the EU, "sectoral cooperation and exchanges with the Russian Federation."

Acting together with the EU, the US Department of the Treasury's 12 September statement said that the sanctions, "prohibit the exportation of goods, services (not including financial services), or technology in support of exploration or production for Russian deepwater, Arctic offshore, or shale projects that have the potential to produce oil" to Gazprom, Gazprom's oil division Gazprom Neft, Lukoil, Surgutneftegas, and Rosneft. US companies partnering with those five companies had until 26 September to wind down transactions, although the government later reconsidered and gave the ExxonMobil and Rosneft Kara Sea joint venture until 10 October to close operations and withdraw from Universitetskaya-1 well.

"Today's actions demonstrate our determination to increase the costs on Russia as long as it continues to violate Ukraine's territorial integrity and sovereignty," said Under Secretary for Terrorism and Financial Intelligence David S. Cohen in a statement. "The US, in close cooperation with the EU, will impose ever-increasing sanctions that further Russia's isolation from the global financial system unless Russia abandons its current path and genuinely works toward a negotiated diplomatic resolution to the crisis."

The department warned that further sanctions under executive orders 13660, 13661 and 13662 could be handed down should Russia not move to de-escalate the situation in the Ukraine and withdraw.

"The US sanctions seem to have a clear purpose: to prevent Russia from developing what Russia sees as its most promising oil and gas resources in the medium- to long-term," Alexei Kokin, senior oil and gas analyst for Moscow-based URALSIB Capital, tells *OE*.

The *Mikhail Ulyanov* oil vessel arrives to load oil from Gazprom's ice-resistant Prirazlomnaya platform on the Prirazlomnoye field. It was the first Russian offshore Arctic field. Photo from Gazprom.

Arctic and elsewhere

Russia is a new producer in the Arctic. Gazprom brought its Prirazlomnoye field off northern Russia in the Pechora Sea online through its Prirazlomnaya platform on 23 December 2013. The national was the first Russian company to produce from the Arctic, the fragile environment which the US Geological Survey says could contain up to 13% of the world's undiscovered oil and up to 30% of its undiscovered gas.

The production was the culmination of many years of intensified efforts in the region over the last few years, beginning in 2011.

On 30 August 2011, Rosneft signed a US$3.2 billion strategic cooperation agreement with ExxonMobil to explore and develop the Russian Arctic and Black Sea regions. In April 2012, coinciding with the deal's finalization, the Russian government overhauled the oil taxation regime to make foreign investment more attractive. That same year, Rosneft also inked a cooperation agreement with Statoil to jointly explore offshore fields in the Russian sections of the Barents Sea and Sea of Okhotsk.

"Offshore fields – especially in the Arctic – are without

In April 2014, the first oil produced from the Russian Arctic Shelf was loaded from the Prirazlomnaya platform onto the *Mikhail Ulyanov* vessel. Photo from Gazprom.

Quick stats

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

New discoveries announced

Depth range	2011	2012	2013	2014
Shallow (<500m)	104	75	72	43
Deep (500-1500m)	25	23	19	17
Ultradeep (>1500m)	18	37	32	8
Total	147	135	123	68
Start of 2014	151	135	98	-
date comparison	-4	-	25	68

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

Reserves in the Golden Triangle

by water depth 2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	13	564.25	1,060.00
Deep	16	2,615.00	2,515.00
Ultradeep	46	13,205.25	18,150.00
United States			
Shallow	21	105.55	352.00
Deep	22	1,570.11	1,714.57
Ultradeep	30	4,160.50	4,180.00
West Africa			
Shallow	169	4,500.97	21,683.05
Deep	49	5,681.50	7,070.00
Ultradeep	16	2,055.00	1,610.00
Total	382	34,458.13	58,334.62
(last month)	(385)	(34,656.63)	(60,039.62)

Greenfield reserves

2014-18

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	1194	45,061.36	765,596.08
(last month)	(1212)	(46,149.75)	(768,938.05)
Deep	160	12,427.98	100,235.27
(last month)	(160)	(12,572.98)	(100,205.27)
Ultradeep	105	19,550.15	56,787.00
(last month)	(106)	(19,580.15)	(58,527.00)
Total	1,459	77,039.49	922,618.35

Pipelines

(operational and 2014 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	40,897	(40,734)
Planned/ possible	24,820	(24,806)
	65,717	(65,540)
8-16in.		
Operational/ installed	79,249	(78,739)
Planned/ possible	50,522	(49,951)
	129,771	(128,690)
>16in.		
Operational/ installed	91,751	(91,226)
Planned/ possible	48,055	(48,180)
	139,806	(139,406)

Production systems worldwide

(operational and 2014 onwards)

Floaters		(last month)
Operational	281	(280)
Under development	41	(40)
Planned/possible	351	(346)
	673	(666)
Fixed platforms		
Operational	9,258	(9,270)
Under development	134	(123)
Planned/possible	1,431	(1,432)
	10,823	(10,825)
Subsea wells		
Operational	4,575	(4,565)
Under development	380	(379)
Planned/possible	6,616	(6,527)
	11,571	(11,471)

Global offshore reserves (mmboe) onstream by water depth

	2012	2013	2014	2015	2016	2017	2018
Shallow	5,984.58	23,457.06	45,196.80	33,604.85	29,744.12	44,846.62	26,838.16
(last month)	(6,118.71)	(23,494.56)	(45,160.09)	(35,778.03)	(28,642.82)	(45,844.06)	(26,878.66)
Deep	2,791.02	484.3	4,155.36	5,337.00	3,851.57	5,267.44	11,479.56
(last month)	(2,791.02)	(484.30)	(4,197.20)	(5,659.50)	(3,369.61)	(5,232.15)	(11,772.19)
Ultradeep	737.15	2,932.94	2,758.62	1,869.95	5,162.70	12,930.01	6,840.86
(last month)	(737.15)	(2,932.94)	(2,758.62)	(1,908.77)	(5,207.70)	(13,141.57)	(6,921.06)
Total	9,512.75	26,874.30	52,110.78	40,811.80	38,758.39	63,044.07	45,158.58

16 October 2014

Image of the Kara Sea's winter 2014 ice expedition organized by the Arctic Research and Design Center, a joint venture between Rosneft and ExxonMobil. Rosneft said it was the largest expedition in the Arctic Ocean since the fall of the Soviet Union. Photo from Rosneft.

any exaggeration our strategic reserve for the 21st century," Putin said in a transcript released by the Kremlin on 13 April 2012, noting that the country needed to address technological, infrastructure and environmental issues that would require substantial investment. The regime overhaul included reductions on the mineral extraction tax and exemption from export taxes for a parcel of offshore fields – including some assets in the operationally-expensive, risk-laden Arctic.

"I think it's no secret that the Russian companies do both need international financing and technical expertise to go into deepwater offshore exploration, so in the short term the sanctions effectively halt any exploration activities," Dr. Anna Belova, GlobalData's lead upstream analyst for the former Soviet Union, tells *OE*. "The fact is that it's a very high-risk operation that carries a very high price. That's where they need international partnership.

"The Russian government definitely saw those areas as very strategic to the well-being of the country and balancing the budget. That's why the sanctions hurt so much - because they target these strategic areas," Belova says.

The future of one project in particular is at risk: the Universitetskaya-1 well, rumored to have cost $700 million. On 9 August, the Rosneft and ExxonMobil joint venture spudded the Universitetskaya-1 well on the East-Prinovozemelskiy-1 license area, despite EU sanctions being made effective 31 July. Rosneft announced on 27 September that the well discovered oil and gas condensate, while thanking its Western partners. Sechin announced that the field would be named Pobeda, Russian for "victory," stating that the preliminary assessment showed 338 million cu m of gas and 100 million tons of oil in just the one structure. A spokesperson for ExxonMobil confirms to *OE* that the Fort Worth, Texas-based company had withdrawn from all ten of the company's Russian endeavors, but would not comment on its future within the country. However, with ExxonMobil currently sidelined, resources might not be extracted any time soon.

URALSIB Capital's Kokin says that Rosneft's plans in the Arctic are hit the hardest by the sanctions.

"I don't think Russian companies will be able to pursue deepwater projects on their own beyond early exploration stages. They may be able to shoot seismic using old Soviet ships but drilling an exploration well will require contractors like Seadrill or Transocean. Building a production platform is

ExxonMobil received an extension from the US Department of the Treasury to close down the Universitetskaya-1 well. It was given until 26 September. Photo from Rosneft.

likewise an impossible task for Russian wharfs," Kokin says.

However, Kokin says that the sanctions' effect on Exxon's future in the country remains to be seen, noting that it depends on the length of the sanctions to see if the companies consider it "merely a short-term nuisance."

Exxon has strong ties with Russia, with a history of more than 20 years in the country and net holdings in the Russian seas totaling more than 11 million acres.

"The operating season is over in the Russian Arctic and will resume only in July 2015. In the meantime, there is not much for ExxonMobil to do anyway apart from analyzing the well data," Kokin says.

Belova said that Russian offshore exploration might be relegated to comparably warmer seas, should the sanctions continue.

"I would say that the Arctic offshore is definitely off limits in the short term, but there's still the possibility of doing the Caspian and Black seas because Lukoil has been very successful in the Caspian Sea; we've seen a lot of activity in the past in the Black Sea and Sea of Azov, so we can see some of the offshore activities happening within these inner, more warmer climate seas," she says.

Russia and China are strengthening their ties in what could be a mutually-beneficial relationship: Russia sees an alternate opportunity for access to capital and technology, and China sees access to Russian gas on favorable terms. However, Kokin points out that the relationship might not be the holistic, turnkey solution for which Russia is searching.

"China could help with offshore drilling. CNOOC is producing offshore and could agree to drill in the Black Sea. However, Arctic drilling is not one of CNOOC's competences. For that, Russia will need either majors like BP and ExxonMobil or entrepreneurs like Cairn Energy," he says.

Belova says that Russia's resurgent interest in China is indicative of the country's plan should the sanctions continue long-term.

"If the sanctions stay in place, we can see more of a shift towards other frontier provinces, like Eastern Siberia, and onshore exploration," she says, noting that Russian companies have more technical expertise with onshore developments and that the cost of trial and error is minimal compared with offshore explorations. **OE**

FURTHER **READING**

Read more on Ukraine-related sanctions at OEdigital.com.

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	109	99	10	90%
Jackup	426	374	52	87%
Semisub	188	161	27	85%
Tenders	33	22	11	66%
Total	756	656	100	86%

Gulf of Mexico

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	31	29	2	93%
Jackup	93	75	18	80%
Semisub	29	23	6	79%
Tenders	N/A	N/A	N/A	N/A
Total	153	127	26	83%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	13	10	3	76%
Jackup	116	106	10	91%
Semisub	38	28	10	73%
Tenders	24	14	10	58%
Total	191	158	33	82%

Latin America

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

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	50	49	1	98%
Semisub	45	44	1	97%
Tenders	N/A	N/A	N/A	N/A
Total	96	94	2	97%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	107	95	12	88%
Semisub	3	3	0	100%
Tenders	N/A	N/A	N/A	N/A
Total	111	99	12	89%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	32	30	2	93%
Jackup	26	21	5	80%
Semisub	18	16	2	88%
Tenders	7	6	1	85%
Total	83	73	10	87%

Rest of the World

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	4	1	3	25%
Jackup	25	22	3	88%
Semisub	19	12	7	63%
Tenders	N/A	N/A	N/A	N/A
Total	48	35	13	72%

Source: InfieldRigs

16 October 2014

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

New lease on life

ABS Group's Brian Gibbs and David Hua discuss long-term strategies to extend the service life of aging offshore assets.

Structural integrity is critical to sustaining stable, reliable, and optimal performance.
Images from ABS Group.

As more floating structures near the end of their original design lives, asset owners are evaluating ways to rehabilitate and safely extend service life to avoid nonproductive downtime. A number of service providers offer full life cycle asset integrity management (AIM) programs to facilitate early-stage proactive measures to protect the asset. An effective AIM system is critical to preserving the condition and operability of assets while maintaining compliance with regulatory requirements.

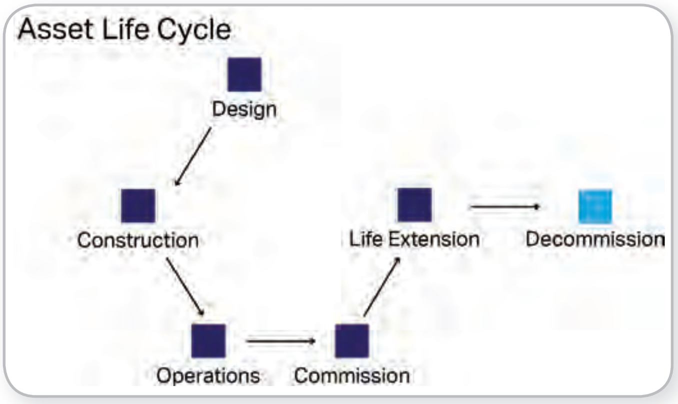
ABS Group develops work scopes, manages in-service inspection programs (ISIPs), and acts as a customer representative during facility visits made by the US Coast Guard and classification society. If structural deficiencies are identified, the company serves as technical advisor to provide solutions and obtain regulatory approval for any necessary repairs.

A new time horizon

For FPSOs and other floating production systems, the intended service life typically is 20-25 years. The scantlings of the structure are designed based on this assumption. For an asset to go beyond the originally approved design life, the owner must demonstrate that the asset can be maintained fit-for-service for the new life span. The critical first step in the decision-making process is determining whether it is feasible to extend the asset's life so it can operate to the new time horizon.

If the asset, such as a spar or semisubmersible, is conventionally moored, the primary line of investigation and preservation targets the integrity of the hull and mooring systems. There are many components that need to be evaluated during the initial assessment. The evaluation includes the integrity of the primary structure, the extent of corrosion or steel loss, the remaining fatigue life, and in many cases compliance with current design codes as well as the additional loads that have been placed on the structure over time (e.g. process equipment). All of these evaluation criteria are fundamental to future asset integrity and require regulatory approval. In some cases, they also must be approved by a classification society.

Once the condition of the structure is assessed, the means of mitigating identified issues can be developed, with options



Life extension is an integral part of the asset life cycle.

ranging from enhanced monitoring to structural refit.

Major challenges

To extend the life of a structure, it is necessary to have in-depth knowledge of its condition. Lack of historical operating data is a challenge when assessing an asset's viability for life extension.

Other challenges include previous damage, deteriorated process equipment, noncompliance with new regulations, a change in flag state, the potential for the asset to operate in more severe environments, weight issues (such as marine growth or additional equipment), and structural capacity. A lack of proper maintenance procedures also can contribute to gradual deterioration.

Life extension readiness

The life extension program evaluates life extension readiness. The approach to the program developed and employed by ABS Group consists of assessing the facts and completing a preliminary assessment to reduce study uncertainties.

Evaluating an asset for life extension begins with obtaining and reviewing the baseline information. The purpose of this first phase of work is to estimate the likely level of effort that will be required to extend service life for the desired number of years. The decision is both a technical and economic one: is there sufficient justification to extend the life of the asset based on likely upgrades and repairs required versus future production rates? Thickness gauging records, for example, can provide insight into the rate at which the asset is corroding. Assuming the asset will be in the same geographic location, this corrosion rate can be used to predict the vessel's condition in the future. In turn, this allows the estimation of the likely tonnage of steel replacement needed to restore the structure to acceptable condition. Overall, the assessment of the facts involves collecting and reviewing class records, weight control records, thickness gauging reports, and inspection reports.

Once the status of the asset is known in terms of its current condition and compliance with current design codes, a more detailed assessment is performed. The more detailed assessment could include global reanalysis of the hull structural model, focusing on the fatigue-sensitive areas and any areas with substantial or excessive corrosion.

The asset undergoes non-destructive examination, during which engineers gather ultrasonic thickness measurements following appropriate classification requirements. The final step in this phase is inspection of underwater structures: appurtenances, moorings and tendon systems, risers, and corrosion protection systems are variously inspected for damage, external corrosion, cracking or other deterioration. From this information, a preliminary assessment is completed to reduce uncertainties.

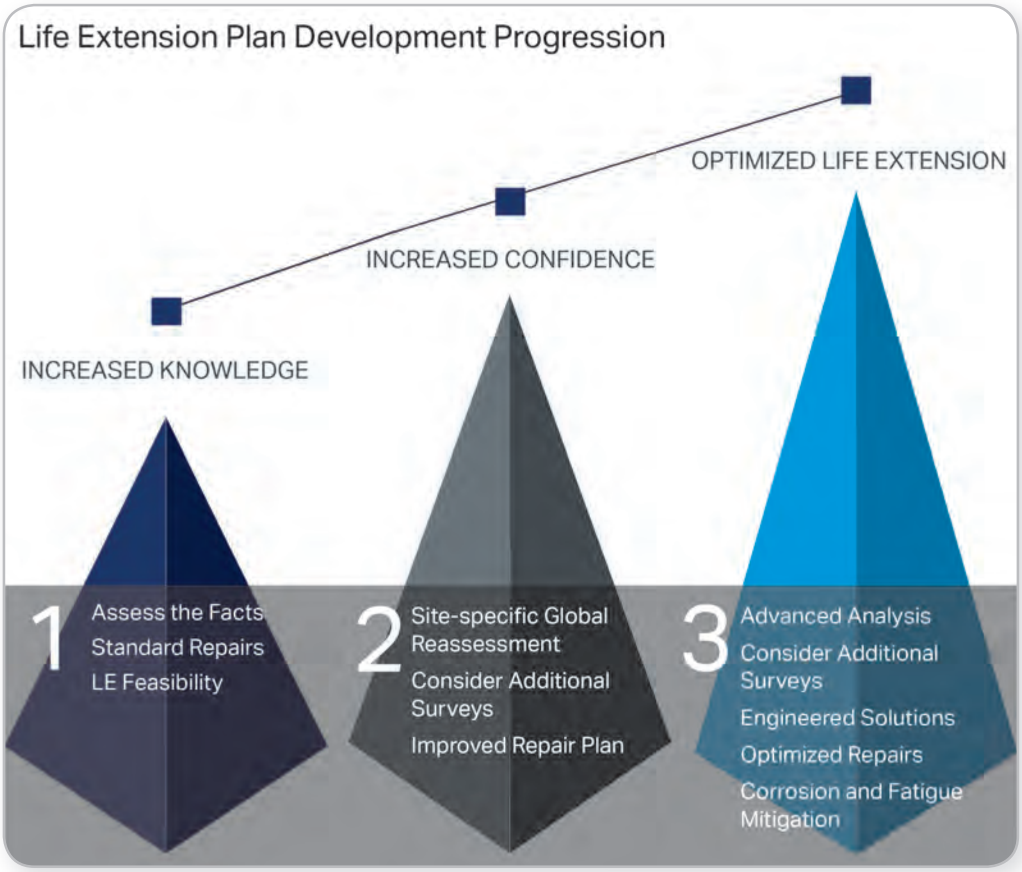
At this point, the team conducts a corrosion evaluation and carries out a scantling assessment, identifying areas requiring repairs or upgrade and defining solutions for structural strength and structural modifications to fatigue-prone locations. Equipment upgrades and other life extension activities also are identified.

It may be necessary to complete advanced analysis to determine the requirements of upgrades to activities, or repairs or modifications to equipment. Engineering analyses can include global strength analysis, spectral fatigue analysis, and local finite element analysis of critical components or areas. The fatigue and strength sensitive areas are screened, and the fatigue lives for the most sensitive connections are determined.

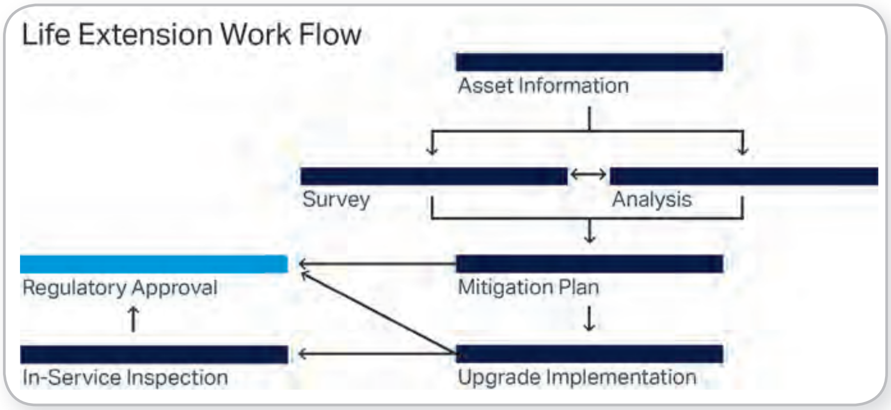
Using the results of the analyses, the team develops a set of life extension recommendations that can include:

- Identifying areas of the asset where remedial actions are recommended to meet the design fatigue life required for the proposed service.
- Identifying necessary design changes and modifications.
- Determining the value of condition monitoring systems in the ongoing monitoring of system health.
- Revising the existing ISIP.

The final stage of the process consists of issuing a plan for regulatory approval and developing and implementing the corrective action plan.



Following a recommended life extension process helps owners better understand the condition and capability of an asset to address any deficiencies. The benefits to operators are straightforward: improved inspection and planned maintenance, more confidence in future performance, compliance with new regulation and classification society rules, and increased return on investment.



ABS Group's life extension program work flow illustrates how life extension risks are managed. A systematic approach to data evaluation, survey, and analysis is adopted leading to the development of mitigation plans and facility upgrades.

Putting the process to work

The focus of a life extension study is to demonstrate that careful reevaluation of the design and informed assessments of expected future damage, including fatigue and corrosion, contribute to successful life extension.

In many cases the studies are carried out at the end of the original design life, but this is not always the case. One study performed by ABS Group evaluated a deepwater non-ship-shaped floating production installation that had been in service for less than half its design life. A routine periodic inspection of the ballast and void tank structure revealed conditions ranging from coating breakdown and blistering to total coating failure and associated corrosion. With life extension in mind, the asset owner addressed these issues by cleaning and eliminating corrosion sources, such as water ingress and humidity and correct treatment of ballast water.

Another example shows how careful and comprehensive measurement, combined with the knowledge of structural behavior, prevented the need for steel renewal in a watertight compartment. A leak in chain locker drains had allowed water to enter the void space below, causing extensive corrosion and pitting of the uncoated bottom plate. The conventional practice would have been to cut out and replace the bottom plate, but this was not practical because of the restrictions on hot work.

To attack the problem, the team implemented a comprehensive gauging program to record the size, depth, and number of pits. Next, the team determined a reduced effective plate thickness using techniques that account for the presence of pits, combined with the gauged plate thickness. From these data, the effective plate thickness was calculated. The analysis determined there was sufficient remaining strength without any repairs.

Another concern was the risk of loss of water-tight integrity should the pits penetrate through the full plate thickness. This issue was addressed by eliminating the source of water ingress and thoroughly drying the void space. Enhanced monitoring was recommended to assure that wet conditions that could lead to corrosion and pitting would be detected at an earlier stage.

In another case, a routine survey of a FPSO revealed that a substantial portion of a horizontal girder in a wing ballast tank was corroded beyond the renewal limit. Again, the conventional approach would be to cut out and replace the defective steel. Hot work was not a major issue in this case, but the practicalities of large-scale renewal of structural steel while the FPSO was on station created major restrictions for the repairs. Gaugings taken during the survey were sufficient to develop a good picture of the extent and location of corrosion.

As part of the team's evaluation, the girder was divided into zones across its width, and a thickness was assigned to each zone. New section properties were calculated, and as a result, the team determined that the section properties could be augmented by additional stiffening as an alternative to the conventional cutout-and-renew approach. The dimensions of the repair steel were selected to allow the pieces to pass through the tank hatch and to be moved into place without the use of power equipment – only chain falls were required.

These few examples illustrate how in-depth understanding of structures and novel approaches can be applied to asset service life.

Experience leads to solutions

While design life is not an exact calculation and involves uncertainties, assumptions, and conservatism, software tools are becoming more sophisticated, and engineers can better model a structure's behavior to determine recommended actions.

Owners that want to extend the operational life of offshore assets have access to a number of creative mitigation solutions that can be carried out by experienced teams with the knowledge to rehabilitate aging offshore units. The benefits of these programs are substantial and can minimize the loss of production that would normally result from removing the critical infrastructure from the field for a prolonged repair program. **OE**

Brian Gibbs *is director of inspection and verification services for ABS Group. He has spent more than 30 years of his career in asset integrity management (AIM). He is experienced in condition assessment, corrosion technology, failure analysis, corrosion prevention, maintenance strategy development, technical due diligence, risk assessment, ISIP maintenance, risk-based and prescriptive verification, and design and implementation of AIM programs.*

David Hua *is director of engineering for ABS Group. He has designed both commercial and naval vessels. Hua led the development of a Rapid Response Damage Assessment system, conducting engineering analyses, inspections, and risk assessments for the first FPSO in the US Gulf of Mexico, and he has developed ISIPs such as risk-based inspections for spars, semisubmersibles, and TLPs. He has hands-on experience in life extension projects on both ship-shaped and non-ship-shaped facilities.*

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Aging infrastructure under wraps

Simon Frost explains the role of engineered composite repairs in late life asset management.

A tubular brace, having suffered wall loss through external corrosion, was reinstated to its original flexural strength with an engineered structural composite repair. Photos from Walker Technical.

The North Sea's aging assets pose a number of challenges for the industry in the UK. Several assets on the UK Continental Shelf have been in operation for 30 years and are expected in some instances to remain in service for a further 20 years. Recent fiscal changes, including a brown field tax allowance and greater certainty on decommissioning costs through the decommissioning relief deed, will likely lead to an increasing number of asset life extension projects.

Operators should recognize that the structural integrity of an asset needs to be maintained during its operational life and even after cessation of production, through any unmanned phase and preparations for removal, until the asset is finally removed. This means structural integrity, subsea, in the splash zone and on topside structures, including components such as pipes and pipework, beams, decks, struts, stairways and towers, must be closely monitored, maintained, and plans made for their continued safe operation.

While operators have the option to replace components, the evolution of many assets has rendered some components inaccessible, making replacement difficult. Replacement can also be costly and might not be deemed good value for a platform nearing decommissioning or where bed space offshore is limited, as replacement can require additional manpower over relatively long periods.

Engineered composite repair solutions

Engineered composite repairs offer an alternative solution and can be completed in shorter timeframes. Composite repairs have been used offshore for a number of years, primarily on pipework with localized corrosion defects, but also in tanks and vessels. However, the engineering principles are also valid for the repair of structural components.

Composite repairs are governed by ISO/TS 24817 or ASME PCC-2 Article 4.1 standards, which define the qualification requirements, design rules, installer training requirements and installation guidance.

Composite repairs are used for a number of reasons. First, no hot work is required – an important benefit when offshore safety requirements render hot repair solutions impractical. Second, once applied, composite repair systems are corrosion resistant and can be guaranteed for up to 20 years – potentially the life of the field. Furthermore, if the corrosion on the structure is external, applying the repair will prevent further material loss. Third, in some instances it is possible to apply a repair while the pipework is in service, allowing production to continue. Finally, composite solutions can be used to repair most defect types in the offshore oil and gas environment. The only defect type where careful consideration is required is crack-like defects.

The technology

A composite repair consists of two main components: a composite laminate (either an impregnated carbon or glass cloth with a thermosetting resin, e.g. epoxy or polyurethane) and an adhesive (either an epoxy or polyurethane resin).

A critical aspect of the installation process is adhesion, irrespective of the specific application. In most cases, the performance of the composite repair is not limited by whether the repair can withstand the applied loads, but whether the loads can be transferred from the underlying pipework or structural component into the composite laminate. To transfer the loads, the adhesive layer between the component and composite repair must withstand and carry out this transfer. Therefore, it is crucial to understand the parameters that influence adhesion. There are five main factors for consideration. These are:

- Surface preparation
- Component material
- Surface cleanliness
- Repair material – primarily the resin
- Environment – humidity, dew point temperature

The most important parameter is surface preparation. To

Get one thing straight

E3 Modulevel®	Torque Tube
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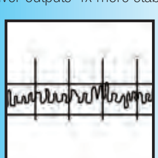
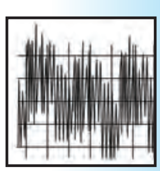
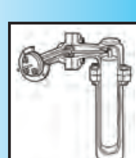
• Range spring's 1.25" range of motion and turbulence- and vibration-dampening effect deliver outputs 4x more stable than torque tubes  	• Torque tube travels only 0.63" into controller and is negatively impacted by turbulence and vibration  
Structural Integrity	
• Range spring not susceptible to friction, eliminating wear • Enclosing tube is 0.09" thick, for robust, corrosion-resistant pressure boundary • Static pressure seal prevents fatigue failure	• Knife-edge bearings create friction as the displacer moves, inducing wear and tear • 0.01" thick enclosing tube prone to corrosion • Flexing torque tube serves as process pressure seal, promoting fatigue failure
Ease of Use	
• Compact vertical design and removable/rotatable head easy to install and maintain	• Heavy assembly and large tube-arm footprint difficult to handle

Outstanding output stability, structural integrity and ease of use make the E3 Modulevel® displacer transmitter a better level control solution than torque tubes.

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A container storage area was identified as suffering from severe corrosion or through wall defects totaling an area of 48sq m requiring repair.

achieve the greatest adhesion, a surface prepared to Sa2.5 is required. Other surface preparation techniques, i.e. power tools or hand tools which provide an ST3 or ST2 surface preparation, respectively, can also be considered. It should be noted, however, that a surface prepared to an ST2 preparation has 25% of the adhesion value of a surface prepared to Sa2.5, i.e. the pressure retention capacity of the repair is significantly reduced when composite repairs are applied to pipework prepared only to ST2.

It is critical that the installation is implemented according to the provided installation method statement. If the surface preparation and other installation procedures are not correctly followed, the repair may leak or fail, regardless of the sophistication of the design.

A bespoke quality control/quality assurance process should also be developed for each composite repair application.

Practical solutions

Walker Technical performed a composite repair on a tubular brace on the cellar deck of a platform in the UK Southern North Sea. The 14in. diameter, 16mm-thick carbon steel brace, had been in service for 26 years and had suffered up to 10mm wall loss through external corrosion

A Walker Technical technician working infield.

at the intersection with a vertical column member. An engineered composite repair that would provide the required flexural stiffness was required, as there were concerns that the brace may be unstable under compressive loading at the corroded area. Furthermore, it was expected that humidity would create limited windows for installing the repair.

The design approach adopted for the repair was split into two parts. The first involved the use of a uni-directional carbon fiber, epoxy resin reinforcement (Technowrap HP PRS), to provide the flexural stiffness to the brace, and the second consisted of a quasi-isotropic carbon fiber, epoxy resin reinforcement (Technowrap SRS) to ensure load transfer continuity between the brace and the vertical column. This ensured the repair would both withstand the applied loads and remain operational for a 20-year lifetime. The repair application took 14 days to complete.

Floating production

Walker Technical was asked to undertake a deck repair within a food container storage area covering about 48sq m on a 15-year-old floating production vessel in the northern North Sea. The work scope was to provide a repair able to withstand a 800kg/sq m working load and impacts up to 1.5kJ, including design calculations, and the installation of Walker Technical's Technowrap DRS (Deck Rehabilitation System, a rubber toughened composite repair system).

In order to remove surface scale and corrosion product the engineering team used ultra-high-pressure jetting to prepare the surface of the area to be treated. However, the jetting caused some flash rusting issues. Bristle blasters were then used to remove any remaining corrosion products. The Technowrap DRS system was applied and an anti-slip coating was then applied over the repaired deck area. The entire project took seven days.

Previously, the quality of adhesion obtained when applying composite repairs to cunifer pipe was poor as the material is soft and therefore, when prepared, the surface finish does not

A Cunifer grey water drain line was suffering from a pin hole leak. An engineered Cunifer composite repair was applied to reinstate the integrity of the pipe to its original form.

have sufficient roughness or irregularity. To solve this issue, Walker Technical developed a resin system (Technowrap Cunifer) that provided greater resistance to interfacial crack growth, enabling the repair to achieve improved pressure containment. This technology was used when a 4in. Cunifer grey water drain line had suffered internal erosion, which had created a pin hole through wall defect. To stop the leak, a temporary repair was applied over the defect.

Due to its role in the operation of the platform, the line could not be shut down or depressurized, implying that it was not possible to remove this temporary repair. Walker Technical had to reinstate the integrity of the grey water drain line and provide a 20-year design life. The drain line's surface was prepared using a bristle blaster and the temporary repair profiled over using fast curing cementitious filler. The composite repair was then applied over the temporary repair and extended onto the cunifer pipework.

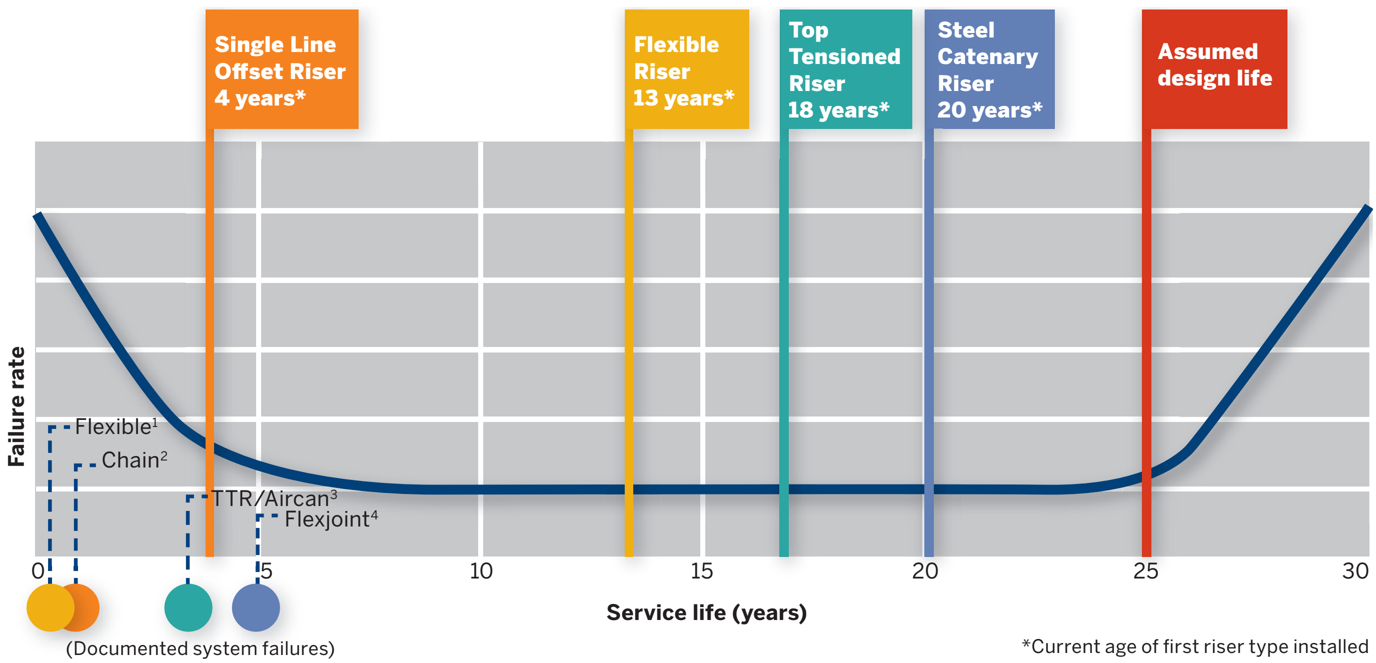
Engineered composite repair solutions offer a cost-effective solution for the myriad of integrity challenges facing operators as part of late life asset extension projects, ensuring that the integrity of their assets can be maintained while still in production, through to the point where they are removed as part of decommissioning process. **OE**

Simon Frost serves as technical director for Walker Technical Resources. He holds a PhD from Cambridge University. He is a visiting professor at Newcastle University, chairman of ISO/TC 67/SC 6 workgroups on GRP piping and composite repairs. He is also a member of the structural materials college for assessing grant submissions to the Engineering and Physical Sciences Research Council.

Extending the life of steel catenary risers

John MacDonald and Lee Tran of 2H Offshore discuss a methodology to help operators extend the life of steel catenary risers in order to keep pace with new subsea tiebacks projects.

SERVICE LIFE (IN YEARS) VERSUS FAILURE RATE.



*Current age of first riser type installed

Images from 2H Offshore

A number of production and export steel catenary riser (SCR) systems in the Gulf of Mexico (GOM) are approaching the end of their design life – typically 20-25 years – which is the anticipated time of use for the SCR that designers will use in their calculations. Operators are challenged to extend the life of existing SCRs to keep pace with subsea tieback wells. The answer to this challenge is to conduct a life extension assessment.

An overlay of a bathtub curve showing the component failure rate versus the number of years different GOM risers have been in operation shows two distinct trends. First, GOM riser component failures, to date, show recorded failures have been early in life due to unexpected circumstances. Second, the earliest installed SCRs are approaching the end of their design life, which means an increased likelihood of aging failures.

Premature failure of an SCR would most likely occur due to the presence of a variety of different anomalies that were not expected in the original design. In addition, the risers approaching the end of the design life were originally anticipated to be pulled out of service. However, a number of SCR systems are likely to be used beyond their original design life and will need a life extension assessment.

Life extension assessment

Engineers need to reassess the situation based on the new projected design life. For example, consider an SCR that has been designed for 20 years' service, which after the 18th year carries produced fluids at a much lower flow rate (typical at the end of life of a deepwater field). A new well is drilled nearby to the existing riser and is expected to produce for seven years. Rather than install a new riser, savings can be found by demonstrating that the existing riser can meet the combined 25 year service life. To accomplish this, a life extension assessment is carried out in three stages:

1. System design and operational information is gathered.
2. The current SCR condition is evaluated against "fitness for purpose" requirements.
3. The condition at the end of the new service life is predicted

based on a combination of the existing conditions and remaining predicted design loads.

Determining whether life extension of an SCR system is possible requires understanding and evaluation of the potential failure mechanisms. These could be overstress, fatigue, internal or external corrosion, erosion, elastomer failure in the flexjoint, blockage or something that gets dragged across the SCR such as a mooring line.

Evaluation of each failure mechanism requires past operational data, direct assessment measurements, future expected operational data and system modeling. While the process is a straightforward one, in reality the information needed to complete each step is often interspersed with gaps and inconsistencies. For instance in the GOM, most of the infield flowlines and risers are not designed for in-line inspection, and where this is possible, the inspection technology often has inadequate resolution/accuracy to identify small but critical cracks or flaws in the system. Finally, where direct assessments such as a cathodic protection surveys or ultrasonic tests are completed, the results can sometimes be inconclusive.

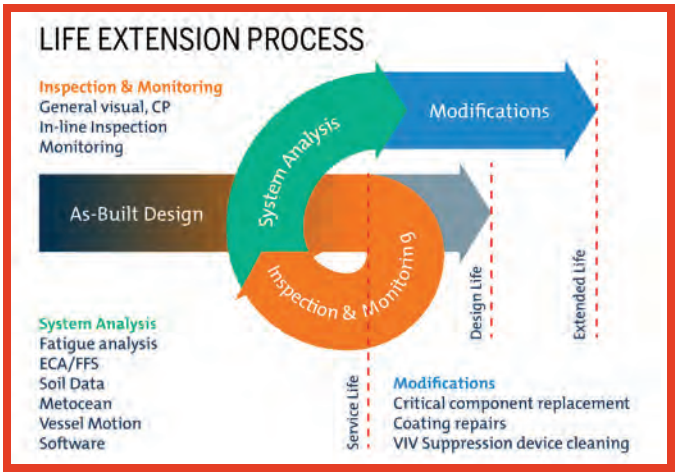
Information gathering

If the possibility of a life extension exists, operators can take small steps during an SCR's operating life to increase confidence in a life extension assessment meeting long-term needs. Below are suggested evaluation methods that can be used to gather information for life extension assessments. Both direct assessment and engineering analysis are discussed.

- **Fatigue**: strain monitoring or motion loggers (for vortex induced vibration) can be used to assess fatigue. Riser analysis software can be calibrated to accurately estimate fatigue life based on actual measured environments. For older SCRs, the analytical methods employed during the original design can be refined with newer software. If good fabrication records are available, then the actual tolerances and material properties can be used. Lab tests can also be conducted using the actual crude oil properties to generate reservoir-specific material crack growth Paris Curves for the fitness for service assessments.
- **Internal corrosion**: in-line inspection PIGS can be used for direct assessment from inside the pipe. Alternatively, newer tools such as ultrasonic inspection or computer-aided tomography can be used externally but only cover a small area. Corrosion probes and chemicals analysis can be used to evaluate general expected amounts of wall loss. Corrosion analysis models can identify the corrosion hotspots to calibrate general corrosion rates from coupons to more specific predicted wall loss values along the length.
- **External corrosion**: in-line inspection PIGS can be used for direct assessment for the outside diameter of the pipe as well. In addition, ROV visual inspection and a cathodic protection survey can be used to assess external corrosion. Advanced imaging technology allows corroded sections to be scanned and mapped for FEA analysis.
- **FlexJoint elastomer degradation**: Similar to the above, a combination of external survey, 3D mapping and predicted degradation rates based on pressure/temperature and rotation data can be carried out.

Information needed for a life extension assessment includes a combination of operational data and direct evaluation of the component, which is then input into an engineering analysis model for evaluation. The problem is where this data cannot be gathered, an engineer must rely more heavily on the underlying analysis assumptions, such as predictions, instead of actual measured data, which increases uncertainty.

Intelligent PIGS can be used to assess internal corrosion.



Life extension assessment activities.

Yesterday's design vs. today's design

One of the main challenges with refining assumptions is accommodating today's design requirements. As more failures occur in the industry, design regulations naturally respond with more stringent requirements, and life extension assessments are no exception to these updated requirements. One example can be seen through changes to governing codes and standards.

Hurricanes Ivan, Katrina, and Rita, which took place during the 2004 and 2005 US Atlantic hurricane seasons, caused significant structural damage to fixed and floating production platforms, semisubmersible and jackup drilling rigs. Among the destroyed were 123 fixed platforms and one floating platform. The US Mineral Management Service (MMS) was concerned about the platforms that suffered significant structural damage, as well as the potential for future damage to key energy infrastructure in the region. In response, the MMS issued new guidelines called the Assessment of Existing OCS Platforms and Related Structures for Hurricane Conditions, which updated

Motion loggers installed on a riser help assess fatigue.

the metocean criteria for use in assessing existing OCS platforms and related structures. Metocean changes such as this affect the expected loading on the riser system and must also be accounted for in life extension assessments.

Further examples of changes in design criteria include unexpected souring of the well or increased pressures and temperatures due to a newly drilled tieback, and changes in analytical methods used.

The bigger picture

Proving that riser life can be extended involves more than demonstrating the fatigue life of the pipe through analysis. Cathodic protection systems, coating systems and flexjoints need verification that they are operating as designed. The life extension of the mounting structure (which is part of the hull, and therefore subject to corrosion, overstress and fatigue) also requires verification. If the analysis predicts that a life extension assessment is not feasible, then other approaches can be taken.

Monitoring of riser motions can be used to determine the actual riser response to a particular environment. The finite element analysis is typically conservative, and having actual measured data allows better calibration of the analysis model. However, the most important item of any life extension assessment is the availability of past design data, knowing the current condition of the component and operational data. This information is key to more confident assumptions and reduced conservatism in the engineering models.

Integrity management (IM) as a process

One of the many advantages provided by a long-term IM program is the ready availability of condition assessment data for an SCR. An IM process by definition requires the periodic condition assessment of the equipment with a few examples described below:

- A design, fabrication, installation and operations dossier (DFIO) is a gathering of the reports, drawings, and assessments completed on a SCR through the life. The DFIO discusses each component, along with an exhaustive listing of documentation related to the component. Adding a hyperlink for each document in the list allows users to quickly find design information such as the baseline fatigue design report as well as documented anomalies.

- Regular inspections are used in IM programs to periodically assess the condition of a component. Inspections may include external visual inspections or nondestructive examinations to verify remaining wall thickness. Anomaly reports are typically used to document inspection or operational observations that are outside of the design intent, or could degrade the component's function. The anomaly reports allow focused assessments and/or repairs through life that maintain in service SCRs in their optimal operating condition. In the context of a life extension assessment, inspection results and anomaly reports increase confidence that the SCR is operating as expected and not subject to premature degradation as opposed to life extension.
- Key performance indicators round out a regular inspection program providing context on how a system is performing as compared with design. For example, the measured wave spectrum can be compared to the spectrum used in the design analysis to evaluate if fatigue accumulation is expected to be less than that predicted. Or more directly, SCR motions can be directly monitored and used to demonstrate that actual motions are less than predicted in the analysis for a given sea state. Similarly, tracking corrosion inhibitor availability and corrosion coupons can give confidence (or otherwise) that corrosion rates are low.

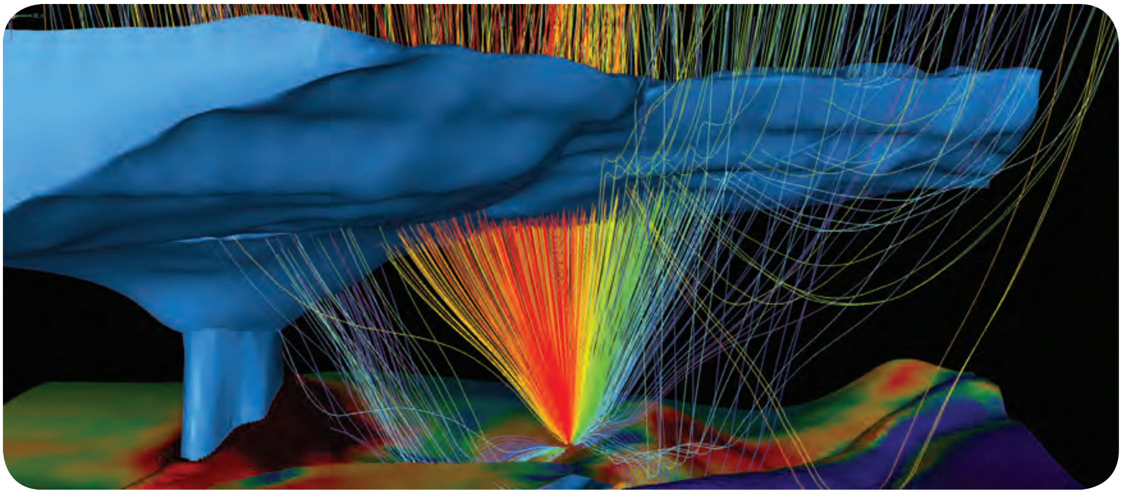
A long-term SCR integrity program completes the first two steps of a life extension, information gathering and condition assessment, on a periodic basis. Significant time and effort is saved when compared to the challenge of going back and gathering details after 8-10 years in service.

Conclusion

As deepwater exploration grows, existing assets continue to age. Extending the life of these assets is economically favorable in comparison to bringing new ones online. Life extension includes evaluation of current conditions and updated predictions about future operations. The evaluation includes both directly measured data and engineering models to predict the remaining service life. With direct assessment being costly and at times inconclusive, the emphasis shifts to analytical assumptions. Nevertheless, with a good understanding of how SCRs operate and degrade, decisions can confidently be made about the service life of the system. OE

__John MacDonald__ is a project manager at 2H Offshore in Houston. He has extensive experience in the integrity management of riser and subsea systems. He holds a BS in ocean engineering from Texas A&M University.

__Lee Tran__ is a senior engineer at 2H Offshore in Houston. He holds a BS in ocean engineering from Texas A&M University and has five years of project experience in finite element analysis and fitness for service assessments of steel catenary risers.



Accurate delineation of salt bodies with massively scalable pre-stack depth migration algorithms and visual quality control capabilities. Image from Paradigm.

Advancing seismic
through advanced science

With its latest software release, Paradigm offers high-definition seismic processing for a general user. Sarah Parker Musarra discussed the powerful new software with Paradigm SVP Indy Chakrabarti.

When a new technology is introduced, it is typically implemented in stages. Companies, like consumers, often do not heft large sums of money at a product any time the next big thing is introduced.

The seismic industry is no different. With the introduction of high-definition data companies are facing down a new technology – and deciding how to maximize the value from these expensive seismic acquisitions. Exploration and production software provider Paradigm attempts to bridge this gap with its latest software enhancement, Paradigm 14.1, which it released in October.

Indy Chakrabarti

While seismic acquisition companies have been shooting and acquiring high-definition data, Senior Vice President, Product Management & Strategy for Paradigm Indy Chakrabarti says that the Paradigm 14 series is a software solution dedicated to subsurface evaluation in high-definition.

Chakrabarti says that the industry is experiencing the same shift that the television industry experienced a few years ago. When the industry switched from a standard definition to a high-definition signal, many did not run out and purchase televisions right away, even though the capacity was there to experience a clearer signal. These people were still able to watch television; they were just not able to take advantage of the more precise image. Similarly, many operators are gathering high definition data, but lack the software systems to properly use it. Paradigm offers hundreds of new features, but in the creation of this particular software system, Chakrabarti says there was no need to reinvent the wheel.

"Of course, [the software] needs to have all the traditional capabilities," he explains. "It's not like it's a brand new system. Just like with the TV, it didn't have to be reinvented; it just needed to be tuned in the right way."

Under the tagline "advanced science for everyone," Paradigm 14 addresses the three components needed to extract value out of high-definition data: performance, scientific techniques and ease-of-use.

"When you have higher definition, you have much larger volumes of data because you are now carrying more content. You have to be able to load those volumes, process data quickly, and then you have to be able to work with it," Chakrabarti says, noting that high-definition seismic volume is hundreds of gigabytes or terabytes in size, so performance is critical.

Scientifically, Paradigm 14.1 can deploy new techniques because of the data's high level of precision, including quantitative interpretation (QI), which, in the seismic domain, characterizes rock, fluid and flow inside a reservoir. Large scale interpretation has always been a part of seismic acquisition, but the upgraded software allows for a reduction in the number of false positive identification of hydrocarbon.

"Drilling down into details, to get into that fine, rich, additional information so that you can discriminate between false positives and real hydrocarbons is what the technique of QI is all about," Chakrabarti says. "It's what you can do because your data is in high-definition."

Another way that Paradigm 14.1 attempts to appeal to an ever-changing industry is through its ease-of-use. Chakrabarti explains that advanced techniques like QI were previously only carried out by specially-trained personnel. That is not always the case now.

"Now with high-definition data, an operator has the opportunity to let lots more folks do this kind of advanced analysis," he says. "Not only do they have the opportunity, they have the need.

"We see declining oil prices in the news today. What that means for operators is that they have to get more efficient in the way they explore. So there's an opportunity with high-definition data and there's a need to get more productive."

Paradigm 14 can also deploy advanced techniques to older data collected in standard definition through broadband processing, which is also commonly referred to by a subcomponent: de-ghosting.

"If you've got high-definition data, then we have a system that has the performance; the scientific techniques; and the ease of use for you to extract information out of it," Chakrabarti says. "If you don't have high-definition data, we have a technique that lets you enhance the definition of your standard legacy data." OE

Close collaboration: drilling with liner

By Mark van-Aerssen, Wintershall Noordzee B.V., Steven M. Rosenberg, Ronald Wever, Ming Zo Tan, Alexandro Salinas, Moji Karimi, and Rex L. Winchell, Weatherford

Weatherford discusses how a collaborative approach helped in the planning and execution of a North Sea drilling with liner operation.

Historically, it has been standard practice to use conventional drilling techniques as the go-to method of choice for drilling challenging wells. However, in some cases, this can lead to major difficulties, such as catastrophic mud losses with resultant high-expense, non-productive time and even complete loss of the hole. Such a situation was facing an operator when drilling a new well in a mature field in the southern sector of the North Sea.

The target of this new well is the virgin pressured Carboniferous reservoir in 3300mTVDSS with a pore pressure of 14ppg EMW (equivalent mud weight). The Volcanics, a heterogeneous formation consisting of around 15 lava flow sequences, separates the Carboniferous from the by production depleted shallower fan carbonate reservoir in 2500mTVDSS with a pore pressure of only 1.7ppg EMW. Above the fan carbonates are overpressured shale formations requiring mud weights of around 14.5ppg to avoid well bore stability issues. Figure 1 illustrates the pressure regime in the well.

Drilling operations in 2012 were unsuccessful in casing off these highly problematic zones using standard drilling practices, including two unplanned sidetracks. All three conventional attempts resulted in major well bore stability problems and severe fluid losses, while not achieving the objective of the well.

Following is a brief breakdown of the three attempts:

1. The 9-5/8in. production casing was set safely above the loss zone

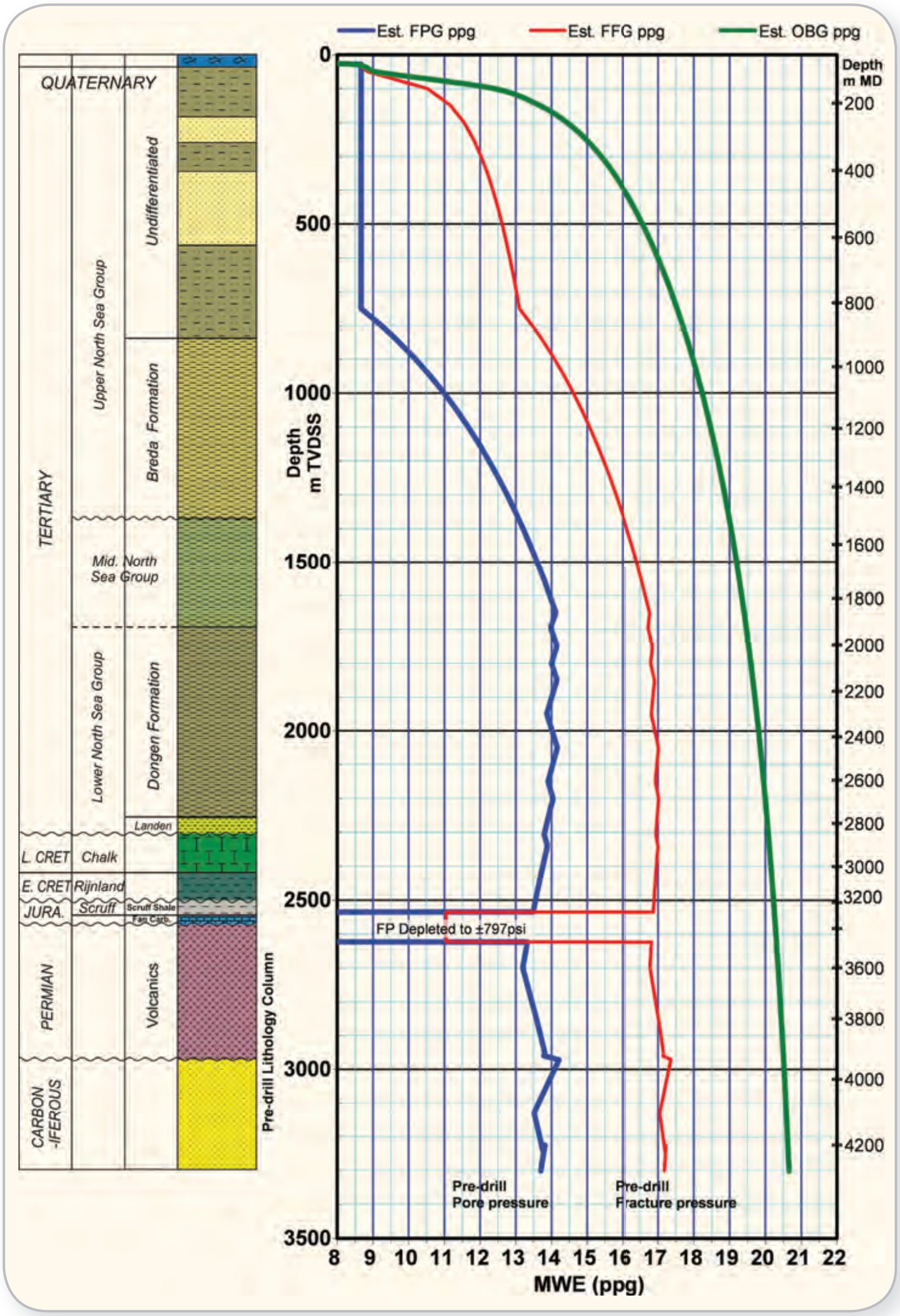


Fig. 1: **Pore, frac, overburden and mud-pressures in the well.** Images from Weatherford.

in the shales using a 14.5ppg mud. Subsequent drilling of 8-1/2in. hole using 9.2ppg mud resulted in collapse of the hole and stuck pipe. The well plugged back into the 9-5/8in. casing.

2. A whipstock exit was set in 9-5/8in casing and 8-1/2in. hole drilled the shales with 11.7 – 12ppg mud but again the hole collapsed.

3. The next try aimed to find a suitable casing depth for the 9-5/8in. to minimize the open hole before entering the depleted reservoir zone. The 9-5/8in. casing was cut and pull and after a whipstock in the 13-3/8in. casing the 12-1/4in. hole was drilled using 14.5ppg mud. However, a suitable shoe depth couldn't be found and total losses were experienced on entering the depleted reservoir zone. The well was temporarily suspended pending a review of operational alternatives and planning of the next attempt to reach target depth.

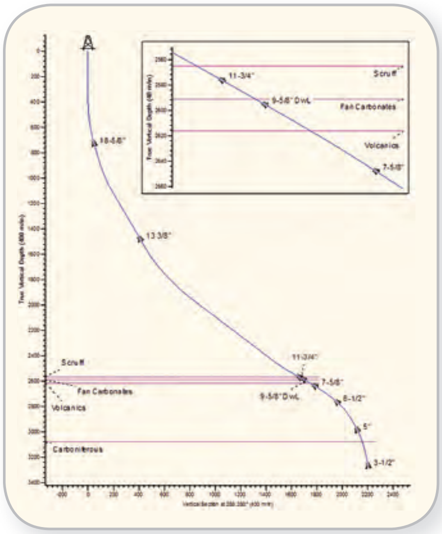


Fig. 2: Casing seats in problematic zones.

The following lessons were learned from these three attempts:

- Drilling the overpressured shale with 9.2 – 12.4ppg mud will cause severe well bore instability, while by using 14.5ppg mud, better stability can be achieved but entering the depleted reservoir will immediately cause total losses.
- Lost-circulation material is totally ineffective therefore no sufficient hydrostatic head can be maintained in the annulus to trip pipe.
- No geological marker is present to aid in selecting a suitable casing seat.

As a result of these unsuccessful operations, the operator carried out a thorough review of the situation and then sought input on how best to approach the problem and achieve objectives, and they in turn provided well engineering and project management services to address the situation. This led to a collaborative approach between the two entities and an extensive evaluation of all the drilling problems associated with the well objectives in the over-pressured Jurassic section of the original holes. As a part of this collaborative environment a front-end engineering design study was performed, which resulted in the decision to drill the shale using drilling with liner (DwL) technology to mitigate the problems encountered. In this way it would be possible to set the liner in the top of the depleted reservoir and subsequently drill it with low weight mud to prevent or at least reduce total losses. This would require that a 11-3/4in. liner be set in the shales, safely above the depleted reservoir and a 9-5/8in.x 11-3/4in. DwL section drilled through the shale and set with the 9-5/8in. casing shoe into the top of the loss zone (Fig. 2).

Fig. 3: 9-5/8in. x 10-5/8in. Defyer DPA drillable casing bit.

This approach involved the use of a liner equipped with a drillable casing bit (Fig. 3) and a liner hanger, as a drill pipe extension, so that drilling the hole and setting the liner and top packer can be achieved with a single trip into the well. This method has proved to be a dependable way of achieving such an objective due to the following:

- The use of DwL techniques has been established as a means of minimizing or even eliminating lost circulation and/or sloughing shale's by what is referred to as the "smear" or "plastering effect." Due to the proximity of the liner to the wellbore, cuttings are smeared against the formation producing an impermeable mud cake that reduces fluid loss compared to conventional drilling methods that would be used to drill the equivalent interval.
- This same proximity also results in smaller cuttings that can be still effectively brought to surface at low flow rates even in the larger drill pipe annulus.
- Once the liner setting depth has been reached, cementation can follow immediately, eliminating the need for another round trip from the well.
- The rigidity of the liner also helps to maintain both deviation and azimuth and since the well deviation was planned to be 60°. This was another important factor.

Early partnering between the operator and service company prior to the planning of the next attempt to achieve the drilling target resulted in a seamless amalgamation of all the engineering disciplines encompassed in the application of DwL technology being integrated into the drilling plan. This resulted in the formation of a detailed well engineering analysis, which took a holistic approach to the well objectives.

This analysis included torque and drag modeling to verify the mechanical integrity of the proposed liner system, special testing, detailed preparation of procedures and simulation modelling for running, drilling and cementing of the 9-5/8in. x 11-3/4in. liner as well as allowing for a contingency plan to run a 7-5/8in. x 9-5/8in. DwL liner in the event that the initial liner could not be drilled deep enough.

As a further contingency, in the event that the 7-5/8in. liner shoe is still in the loss zone or inside the shale section, a 200m length of 6-1/2in. expandable liner was sourced and made available. To prevent differential sticking in the permeable depleted reservoir all liners are equipped with special designed stabilizers even the expandable liner.

During the planning phase regular meetings were held and software to track the project scheduling was created to be sure that equipment deliverables would be completed in the required time frame to meet the various well objectives. Potential problems, drilling hazards and check points were established in order that both entities had a clear understanding of the project and its intricacies. This resulted in additional equipment being sourced and made available, such as surge reduction tools, auto-fill collars, underreamer, centralizers, etc.

The initiation of the above described collaborative endeavor commenced in Febuary 2013, and after a lengthy application engineering process, and some delay in the rig schedule, the operations finally began in early 2014. After re-entry the well was re-drilled from below the 18-5/8in. surface casing shoe. 13-3/8in. casing was set and 11-3/4in. liner had been set and cemented at a depth of 3273m safely above the loss zone. The 9-5/8in. x 11-3/4in. DwL was assembled and run in the well consisting of the following components:

- 10-5/8in. OD Defyer DPA casing bit.
- Stabilizer sub.
- 9-5/8in. shoe joint.
- Float collar.
- 9-5/8in. float joint.
- 9 joints of 9-5/8in. 53.5ppf P-110 Hydril 523 casing
- Liner hanger assembly.
- Liner top packer
- Polished bore receptacle
- A total length of 148m.

The assembly was run and washed down to the 11-3/4in shoe at 3273m and then to bottom at 3282m and drilling commenced using 14.5ppg OBM to a depth of 3302m where fluid losses were encountered. Drilling continued to a depth of 3312m, at an average rate of 3.55m/hour at which point the liner got eventually stuck. Logs later confirmed that the DwL shoe was indeed inside the loss zone proving that the troublesome shales have been successfully cased-off. Some complications were encountered prior to releasing the hanger setting tool, due to high differential pressure between the work-string (seawater) and the annulus (14.5ppg oil based mud), and therefore the secondary release method was used – running and setting a wireline plug at 3163m and pressuring up to 5600psi to release it. A 9-5/8in. tie back string to surface was run and successfully cemented accomplishing the 9-5/8in. production casing string.

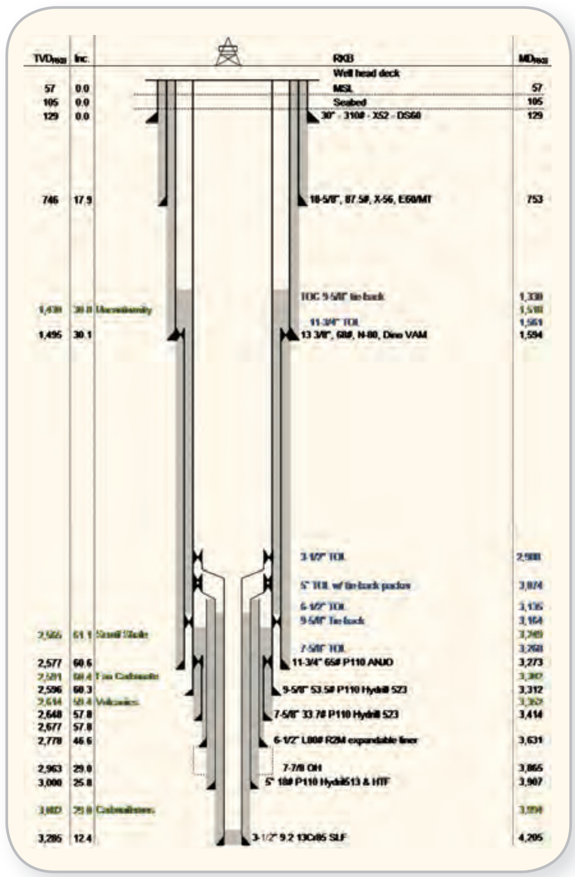


Fig. 4: Well schematic with all casings.

The lost-circulation zone was then drilled with seawater and 7 5/8in. liner was run and cemented 60mMD/30mTVD below bottom of this zone in a DwL configuration in case of any loss of hole diameter after drilling it, but no such problem was encountered. A successful formation integrity test to 15.5ppg was obtained proving the successful isolation of the loss zone.

However, continuous lost circulation issues appeared while drilling the subsequent 6-1/2in. section even after successful cement squeezes. This indicates that the upper part of the Volcanics is connected through fractures to the depleted reservoir formation.

In order to isolate these fractures, a 6in. contingency HydraSkin solid expandable liner was utilized and, due to the unexpected extended length that was required, an additional 260m of HydraSkin solid expandable liner had to be swiftly shipped to the location.

Meanwhile, the 6-1/2in. section was drilled and subsequently enlarged to 7.8in. with a RipTide drilling reamer. During the deployment of the expandable liner it became differentially stuck 230m above bottom, most likely in the additional section which could not be equipped with centralizers on short notice. The liner was expanded and cemented successfully in place, and the drill out of the expandable shoe track was achieved without problem. Because the solid expandable liner was set high there were still some fractures uncovered and therefore a 5in. conventional cemented drilling liner was installed which successfully cased off the remaining fractures. Finally the reservoir could be drilled, although with a reduced ID of 4-1/8in. and as a result a 1200m long 3-1/2in. liner had to be located, assembled and shipped to location all within a very limited time frame (Fig. 4)

The successful conclusion of this operation was an excellent example of an operator and service company working together to solve a major challenge and should be a model for future endeavors in difficult and hazardous conditions. OE

Predicting pressures

With a slightly different approach, hydrodynamic modeling can be used for overpressure prediction in on and offshore environments. Marcell Lux, Ahmed Amran, and Marianna Vincze explain.

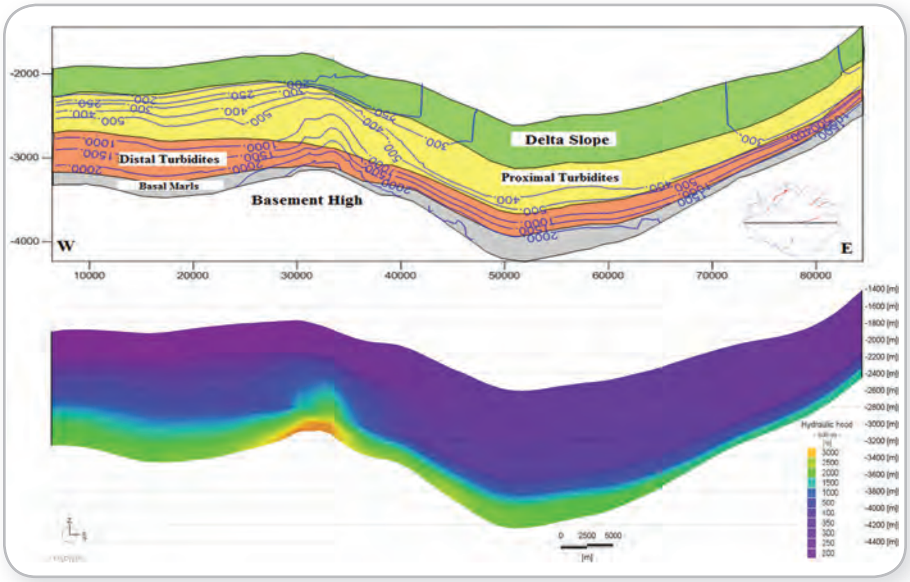


Fig. 1: W-E hydraulic cross section from the southern part of the Pannonian basin. Images from MOL Plc.

Overpressure is a serious problem and a challenge for drillers in many petroleum provinces of the world, including in the Pannonian basin in Central Eastern Europe and in the Black Sea.

MOL looked into how hydrodynamic modeling can be used for (over)pressure prediction onshore and offshore by presenting case studies from the southern part of the Pannonian basin and from the western part of Black Sea, respectively.

Pressure prediction is generally done by detailed analysis of offset well data. A hydrodynamic model can incorporate well data, seismic data and any (hydro)geological information that could improve the model.

By solving the Laplace- and continuity equations it simulates present-day, steady-state conditions, giving a possible realization of the fluid-potential (pressure) field of the study area (Fig. 1 and 2). This enables us to predict overpressure and flow directions, which may also serve as hydrocarbon migration routes. Naturally, the reliability of the model prediction depends on the quantity and quality of the available data and on how appropriate the boundary conditions and the modeler's geological assumptions are.

Since MOL's core exploration area has been the onshore Pannonian basin for over 75 years there was more data available compared to offshore. This data allowed for more detailed 3D hydrodynamic modeling in the Pannonian basin. Conceptual 2D modeling was done in the western part of Black Sea due to fewer data.

Pressure-elevation (p(z)) profiles show significantly overpressured zones and super-hydrostatic gradients from both study areas. Overpressure is usually formed by rapid sedimentation when pore water cannot leave the sediments and it has to carry the burden of impermeable overlying layers, which act as a pressure seal. Since this seal is thought to be responsible for maintaining the overpressure, its permeability, porosity, thickness and geometry are of crucial importance. In the Pannonian basin these are delta slope sediments, whereas in the Black Sea these are Miocene rocks below the Intra-Pontian Unconformity (IPU).

Some calculations (Almási, I.: Petroleum Hydrogeology of the Great Hungarian Plane, PhD thesis, 2001) suggest that overpressures formed during sedimentation should have been at least partly dissipated in geologic times, even through very low permeability pressure seals. However, this is not the case, which means there must be an additional phenomenon maintaining overpressure. Some geoscientists believe it could be – among others – tectonic compression. These are assumptions that have to be made and transformed into boundary conditions in order to model overpressured areas regardless of whether it is on- or offshore.

Since the natural flow system is modeled, steady-state conditions are assumed, which means the model converges to equilibrium where initially overpressured cells would become hydrostatic. To avoid this, constant head cells have to be applied at the bottom of the model space to maintain the overpressure (i.e. to simulate the effect of tectonic compression).

The main difference between on- and offshore modeling is between the boundary conditions applied to near surface layers. Onshore, the undulations of the terrain create gravitational flow systems, where water flows from recharge areas

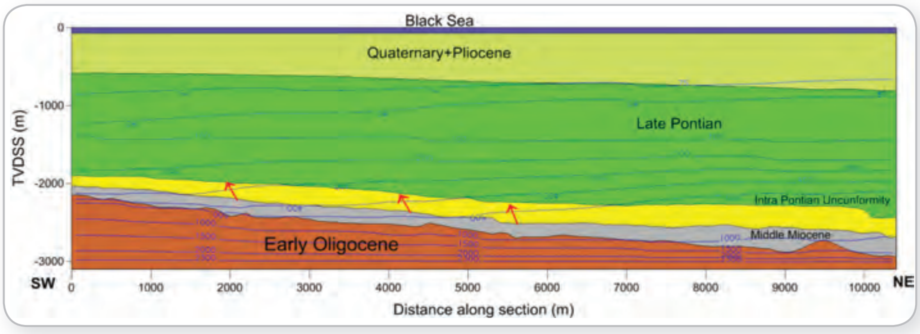


Fig. 2: SW-NE hydraulic cross section from the western part of Black Sea.

to discharge areas. In these flow systems the main flow direction is horizontal in the midrange areas. It can be observed on Fig. 1 where near vertical potential lines indicate horizontal flow in the upper part of the section. If there is an underlying overpressured zone then it will be superimposed and limit the downward extension of the gravitational system resulting in upward directed flow.

In an offshore environment the pressure exerted by the water column above the seafloor has to be considered and this would result in constant head cells for the layer just on the seafloor. In our case study from the Black Sea, the water depth is approximately 70m, which is about 7bar constant pressure on the seafloor. The modeled section is approximately perpendicular to the dip direction of the slope, therefore water depth was assumed constant along the section.

Once boundary conditions are set the pressure distribution will be defined by the porosity, permeability and the geometry of the model layers. The parameters of the pressure seal will mainly influence how super-hydrostatic pressure dissipates with distance.

Figure 1 depicts hydraulic cross sections from the Pannonian basin, where the fluid potential field is represented by equipotential lines. There are two almost identical sections on the figure because the simulation was run with two different methods: finite difference and finite element method. Both methods start from the Laplace- and continuity equations that describe permanent flow, but the mathematical method for solving these equations and the geometry of the model grids are different.

Figure 1 shows that flow is mainly directed upwards, since it is perpendicular to the equipotential lines. Potentiometric mounds occur above the basement highs, which suggests that extreme overpressures are related to the horsts of the basement. Above basement highs flow directions have horizontal components that show toward deep grabens. No significant discrepancy can be observed between the results of the two calculation methods, however, the congestion of equipotential lines is more expressed by the finite element method, which is in more accordance with the abrupt pressure change observed on p(z) profiles.

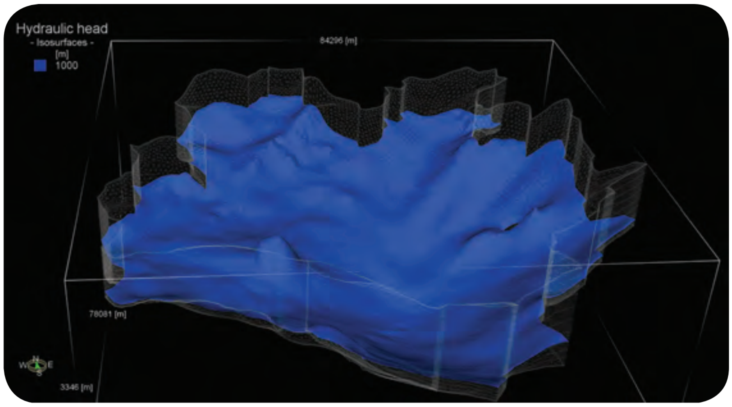


Fig. 3: 1000 m equipotential surface (~10 MPa overpressure) in the southern part of the Pannonian basin.

Figure 2 shows the hydraulic cross section from the western part of Black Sea as a result of the hydrodynamic modeling. It can be noticed from the section that highly overpressured Oligocene layers are sealed by Miocene rocks and the excess pressure is dissipated over these sediments and it slowly disappears above the IPU. As flow is perpendicular to the equipotential lines it is mainly directed upwards. However, it also has a horizontal component showing up-dip of IPU (red arrows). This suggests that IPU might play in important role in hydrocarbon migration.

Since the hydrodynamic model provides a hydraulic head (pressure) value to each single model cell it can be a useful tool for predicting overpressures. There are different ways of visualizing the model prediction.

Figure 3 presents an equipotential surface of the 3D model from the southern Pannonian basin. The 1000m equipotential surface (approximately 10 megapascal overpressure) indicates the depth at which this overpressure would be encountered. It gives an absolute value of excess pressure, which would correspond to different severity at different depths.

On the other hand, figure 4 is a graphical illustration of relative values for the Black Sea: showing pressure values as a percentage in excess of hydrostatic pressure. This can provide very useful information for choosing appropriate mud weight when drilling.

Conclusion

Hydrodynamic modeling can be used for overpressure prediction in on- and offshore environments, however, a slightly different approach has to be taken mainly with regards to boundary conditions.

In general the model results have several practical applications:

- Predicting the spatial distribution of pressure and especially overpressure is of global importance from interrelated economic, technical and HSE (Health Safety and Environment) aspects.
- The determination of migration pathways is of crucial significance from the exploration point of view.
- The presented method can be powerful in both well-explored mature areas and less-known territories regardless of whether it is on- or offshore.

Nonetheless, it can never be overemphasized that all available information has to be carefully studied and evaluated during the modelling process because misconceptions can lead to unrealistic results and misleading predictions. OE

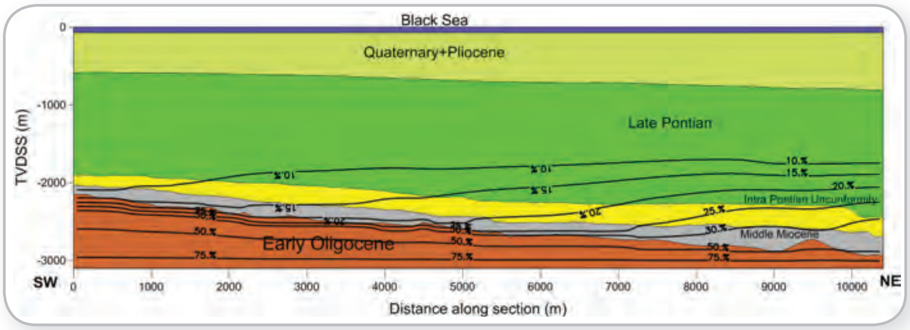


Fig. 4: Overpressure percentages above hydrostatic in the western part of Black Sea.

Marcell Lux *has been with MOL Plc. as an exploration geologist since 2012. He holds BSc in earth science engineering and a MSc in hydrogeology. Currently, he is doing his PhD studies in geology at the University of Szeged specializing in subsurface hydrodynamic modeling.*

Engineering for a cold climate

Arctic-ready facilities: meeting the engineering challenge for a new era of offshore exploration. Mark Manton explains.

The world's energy demand is expected to continue to rise, driven by growth in developing markets. To meet this demand, the energy industry has had to shift to difficult-to-access resources, including those in the Arctic.

The area is largely unexplored and drilling has associated risks due to the Arctic's extreme and environmentally sensitive location. The oil and gas industry recently invested heavily in the technology and preparatory work required to make production in the Arctic more economic. Challenges include designing for powerful seas, extreme low temperatures, deepwater, high winds and, in some instances, all four at once, in the case of "Polar lows."

The key to success of new projects depends upon a greater understanding of harsh environments resulting in improved reliability of the installed equipment.

Practical considerations

Engineers must be aware of environmental cooling mechanisms. The wind chill effect is hugely significant when calculating thermal loss. Classically, ~300W/sq m of heat tracing has been used to protect static equipment and pipework. This prescriptive power demand does not account for uninsulated surfaces, which are exposed to wind chill, e.g. emergency walkways. Emergency walkways must be maintained at +3°C minimum. No heat tracing systems can maintain a positive body temperature at these extreme ambient temperatures when subjected to wind chill, without expending an unfeasible amount of power. For example, it would barely take a 4-5m/s cross wind to make 700W/sq m heat tracing ineffectual across a walkway. The heat tracing power to overcome even a modest cross wind can result in insufficient power available onboard to meet all demands.

The Sable South Centre module being loaded ready for installation at the Sable Offshore Energy Tier II Compression Project, offshore Nova Scotia. Photo from Allseas.

With this in mind engineers must ensure a thorough risk assessment is performed to evaluate wind chill effect. Mitigation solutions may include steam systems required for steam lancing and/or mechanical methods of breaking up ice formation but these need to individually assessed. The safety of the operators remains paramount.

When protecting static mechanical equipment and pipework, insulation is critical. If specified, installed and maintained correctly, it can reduce power consumption. As a rule of thumb, it takes ~250/300g of fuel to generate 1kWh on board a typical platform, therefore operators will be looking for winterization solutions which reduce power/fuel consumption.

Poorly specified, damaged or incorrectly installed insulation will not return the energy savings intended. Insulation materials can be crushed when installed or during maintenance which will significantly degrade performance. It is essential therefore that insulation is correctly applied in accordance with IEEE 515 or equivalent.

Many of the concerns associated with operational and unplanned maintenance in cold climates can be addressed at the conceptual design phase of a project. Engineering design contractors, such as SNC-Lavalin, must establish the client's fundamental needs during this phase and engineers must be shrewd about

their approach to winterization. Adopting a "heat trace everything" approach will be uneconomic. Possible solutions include:

- Accommodating short periods of downtime and therefore circumventing the 100-year minimum design temperature, reducing CAPEX. Equipment must be specified to survive such shutdowns without causing damage.
- Installing smart heat tracing control systems capable of minimizing power demand by factoring in wind speed and direction - the cold face of equipment remains heat traced whilst the sheltered side may be left unprotected, reducing OPEX.
- Limit the use of systems designed to prevent or remove sea ice forming around equipment and walkways. When seas are frozen, there will be no sea spray to blow up on deck. Sea spray is only expected when wind speeds exceed 10m/s. However the potential for atmospheric ice and snow may need to factored in.
- Install waste heat recovery units to generation trains and recycle exhaust from HVAC systems.

Offshore Energy Tier II Compression Project, Offshore Nova Scotia. Photo from SNC-Lavalin

Naturally ventilated or enclosed?

	Naturally Ventilated	Enclosed / Modularized
Human factors	Cold weather conditions can stop or reduce the amount of time operators are permitted to maintain and inspect equipment. Low frequency maintenance or inspection can increase the potential for hydrocarbon leakage.	An enclosed module can be heated to a comfortable level whereby operators can work a complete shift wearing minimal restrictive cold weather PPE. Routine maintenance and inspection can be carried out more easily, minimizing the risk of potential equipment failure or hydrocarbon leakage.
Hydrocarbon gas leak	Detection of gas is possible, however, if the gas is dissipated by the wind it may not be so quick to detect.	Detection should be quicker with gas detection within each module and/or HVAC exhaust.
Leaked gas ignites (explosion)	The concentration of gas may remain low enough to prevent explosion as the deck is naturally ventilated.	Gas will mix with HVAC air and create a highly explosive environment within the container. If concentrations increase and the HVAC shuts down, the gas can potentially displace the oxygen to such an extent that the explosion risk is removed. The environment within the container will however be extremely hazardous when the HVAC is reintroduced to exhaust the retained gas from the area.
Explosion initiates a fire	Air supply all around to maintain the fire until the fuel source is removed.	If the HVAC system shuts down as designed the fire should snuff itself out as the oxygen is used up.
HVAC	Not necessary. Walkways will however require ice prevention heat tracing.	Each enclosed module will require HVAC, providing a comfortable working environment for the operator.
Number of interstitial connections	Less line connections necessary across the platform therefore reducing the number of potential leak paths.	More flanged connections between modules and therefore potential leak paths.
Emergency exit routes	Open decks provide quick and easy access to muster points with minimal obstructions. Winterization will be necessary to ensure walkways are free from ice.	Potentially hampered by multiple blast doorways and airlocks etc. Winterizing the walkways within the modules will not be necessary.

Naturally ventilating, partial or fully enclosed module design

Det Norske Veritas (now part of the DNV GL group) recently issued the Offshore Standard for Winterisation for Cold Climate Operation, DNV-OS-A201. DNV acknowledges that problems encountered in polar operations cannot be easily solved by prescriptive instruction and now favor a more functional approach to engineering design. The key is preparing a detailed winterization philosophy early in the design process. It should be agreed between the operator and contractor and cascaded through to the equipment and heat tracing suppliers.

Equipment layout and modularization is a key decision. It is sensible to locate safety and process critical equipment inboard, where the brunt of the wind and weather will be least felt. Shielding the equipment from the elements may however be contrary to allowing leaked hydrocarbons to escape safely and swiftly. Conventional designs are self-venting, where the process decks are open to the environment on all sides. But, this approach focuses on mitigating the risk associated with leaked gas and does not consider the human factors involved with operation and maintenance.According to NORSOK, the percentage of time that an individual employee is exposed to a wind chill index (WCI) above 1000W/sq m should be reduced as far as reasonably practicable. For arctic installations, outdoor operations should be identified and reduced to a minimum. Shielding workers from the wind will have a dramatic impact on their availability to carry out work.

Equipment inspection and planned / unplanned maintenance will be easier if equipment trains are enclosed or semi-enclosed in heated modules. Conversely, modules will inevitably require more inter-connections as pipework will need to pass between bulkheads. So while enabling more time for maintenance, there could be a greater number of leak paths introduced.

The table shows naturally ventilated vs. enclosed modular platform design. Modern computational fluid dynamic (CFD) modeling is an invaluable tool engineers have at their disposal to understand the effects wind has on platform layouts and informing decisions on whether to add weather / wind shields or enclose modules entirely. Ultimately, the control of energy consumption by a facility will determine its profitability. There is little point extracting these hard to reach hydrocarbons if the majority of them are going to be burnt in the process.

Husky *White Rose* FPSO, Offshore Newfoundland & Labrador.
Photo from SNC-Lavalin

The cost for successfully winterizing an offshore arctic platform will be a significant part of a project's overall CAPEX and OPEX. The combination of both freezing temperatures and wind chill must be considered when specifying and laying out mechanical and safety essential equipment. CFD modeling can assist with layout decisions and can establish whether enclosing modules is necessary for operations.

Electing to fully modularize mechanical equipment into small enclosures or leaving a platform open to naturally ventilate is a difficult and complex decision. It is therefore essential to ensure a detailed, useful and robust winterization philosophy is established with the operator at the very beginning of a project concept. Wherever possible waste heat must be utilized to minimize energy expenditure. SNC-Lavalin believes all technical challenges associated with operating in the Arctic can be overcome through intelligent engineering design if identified early enough. **OE**

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***Mark Manton** is a lead mechanical engineer at SNC-Lavalin. Manton graduated from Nottingham University with a BEng with honors in mechanical design, materials and manufacture. Since then, Manton has completed eight years with SNC-Lavalin, working as a design, project and mechanical engineer on several key onshore and offshore projects.*

Increasing the accuracy of uncertainty data

Photo from NEL.

Sharing information about uncertainty budgets for flow meters could lead to a better understanding of measurement systems, says NEL's Callum Hardie.

While flow meters are calibrated under ideal laboratory conditions, the environments into which they are installed vary greatly. Uncertainty analyses are therefore essential to determine whether measurement systems, once installed, are capable of meeting required performance targets.

However, when developing uncertainty budgets for new measurement systems, it is often difficult to obtain reliable data to provide such evidence. Two main methods are used, the analytical method and the Monte Carlo method.

The analytical method

Calculating uncertainty using the analytical method is described in detail in the Guide to the expression of Uncertainty of measurement (GUM), produced by Working Group One of the Joint Committee for Guides in Metrology.

The technique involves a series of steps:

1. Define the relationship between all the inputs to the measurement and the final result.
2. For each input, draw up a list of all the factors that contribute to the uncertainty in that input.
3. For each of the uncertainty sources make an estimate of the magnitude of the uncertainty.
4. Convert the uncertainties to standard uncertainties by assigning a probability distribution to each uncertainty source.
5. From the relationship defined in step 1, estimate the effect that each input has on the measured result. This is usually achieved by calculating sensitivity coefficients.
6. Combine all the input uncertainties using the root sum squared technique to obtain the overall uncertainty in the final result.
7. Express the overall uncertainty as the interval about the measured value, within which the true value is expected to lie with the required level of confidence.

The uncertainty budgets created using the analytical method are very useful tools for optimizing measurement systems, as the effect of changes in input uncertainties on the output uncertainty can be seen very quickly. The input uncertainty sources can also be ranked to determine which sources have the most significant effect on the overall uncertainty. The process of developing uncertainty budgets can also be beneficial in that it helps to gain a full

NEL's flow measurement facilities, at East Kilbride, Glasgow.

understanding of how the measurement system works.

The Monte Carlo method

The Monte Carlo method is an alternative way to estimate measurement uncertainties and is described in supplement 1 to GUM.

The method also involves a series of steps:

1. Define the relationship between all the inputs to the measurement and the final result.
2. For each input, draw up a list of all the factors that contribute to the uncertainty in that input.
3. For each of the uncertainty sources make an estimate of the magnitude of the uncertainty.
4. Assign a probability distribution to each of the uncertainty sources.
5. Use a random number generator to assign a "measured value" for each input variable based on its uncertainty value and probability distribution.
6. Calculate the final result using the "measured values" as inputs.

This process is repeated many times, until there is enough data to analyze the output distribution. The uncertainty in the final result can then be estimated by calculating the standard deviation of the output data.

The Monte Carlo method has some advantages, for example, it shows the distribution in the output which can be used to view whether the distribution is skewed or rectangular in shape. This technique is also particularly useful when the uncertainties are large compared with the measured values.

It has been shown that the combined use of the Analytical and Monte Carlo methods can be useful. The advantages of carrying out both methods on the same system are:

- The two methods can be used to cross check against each other.
- The Monte Carlo method can be used to show if the output distribution is skewed or rectangular. It can also be

used to ensure that covariances are being accounted for in the analytical method.

- The analytical method can then be used to carry out "what if" analyses, which will show the effects of changes in the input parameters on the overall uncertainty of the system.
- Comparing the two methods is particularly useful when uncertainties are large compared to the measured values when the mathematical theory in the analytical method can break down.

The table below shows the comparison between the analytical and Monte Carlo methods to calculate the uncertainty of a turbine meter. It can be seen that the agreement is within 0.015%. This agreement helps to increase confidence in the uncertainty calculation.

Method Used	Expanded Uncertainty (m3)	Expanded Uncertainty (%)
Analytical Method	10.837	0.110
Monte Carlo Method	9.311	0.095
Difference	1.52	0.015

Comparison between analytical and Monte Carlo methods.

Uncertainty analysis with no historical data

Whatever method is used to calculate uncertainty, one of the most important stages is to estimate the magnitude of uncertainty sources. These estimations can be made from various different sources of information, including historical data from calibrations and verifications. Where a measurement system is newly installed, or if the historical data has not been well documented or is missing, then estimates of the magnitude of uncertainty sources have to be made using other sources of information, such as manufacturers' specifications, engineering judgment or data from similar measurement systems.

Using historical data to carry out uncertainty analyses leads to many advantages. It will allow the operator to determine a more accurate estimation of uncertainty on measurement systems. While other methods of estimating uncertainty sources, such as using a manufacturer's specifications, engineering judgment or data from similar systems, are all acceptable in the GUM, the assumptions made using these methods will lead to a less accurate estimation of uncertainty.

Having an accurate, evidence-based estimation of uncertainty for a measurement system will allow cost-effective improvements to be made to the system in the future. The uncertainty sources can also be ranked to determine which sources contribute most to the overall uncertainty in the system. The uncertainty of these sources can then be improved first ensuring that time and money is not wasted on improving the uncertainty of less significant sources.

Analyzing historical data will also bring benefits to maintenance teams. Typically, maintenance (including verifications and calibrations) is carried out very frequently, especially when a new system is installed, with the frequency reduced over time if the instrument passes verification checks.

However, by analyzing the stability of instruments over a period of time, calibration schedules can be determined based on evidence, rather than choosing arbitrary time periods. This means that instruments that are proving to be less stable can be calibrated more frequently, while more stable instruments can be calibrated less frequently, leading to improved safety procedures as it will avoid the need to break into the line, which involves isolation and depressurization.

The use of historical data also means that if new systems are installed with identical equipment, then evidence will be immediately available for determining initial calibration schedules. If the stability of instruments is likely to reduce over time, then such data will also help determine when these instruments need to be replaced.

Using historical data to carry out uncertainty analyses will also benefit the industry as a whole as increased knowledge of the uncertainty of measurement systems will lead to more effective allocation principles in shared pipelines. It will also help regulators to set regulations which are suitable and achievable based on current industry best practice.

Effective analysis

The estimation of uncertainty in measurement systems can be greatly improved when historical data is available and should be used whenever possible to estimate uncertainty sources. Uncertainty analysis should also be seen as an iterative process, with uncertainty budgets being updated whenever new calibration data is available or changes are made to measurement system.

This means that historical records of calibrations should be kept in good order so that they can be analyzed at regular intervals, which should already be the case if the system is audited. If a system is new or calibration data is not available, uncertainty sources can be estimated by other methods. However the uncertainty values should be updated over time as more historical data becomes available, and it is recommended that as a minimum uncertainty budgets should be reviewed annually to ensure they are still relevant and accurate.

While performance data is generally available on the manufacturer's datasheet, different manufacturers present the data in diverse forms. For example, a coverage factor and/or the stability of the instrument over time is not always given. Manufacturers should therefore make available more data on the performance and stability of instruments over time. This will allow more accurate estimates of uncertainty when historical data is not available.

There should also be more open sharing of data across industry, as this will lead to better understanding of measurement systems which will be beneficial for buyers, sellers, and pipeline users. This could involve the development of a calibration database, which would be very beneficial to the industry as a whole, especially when specifying and selecting new equipment. **OE**

Calum Hardie *is a flow measurement engineer at TÜV SÜD Group company NEL, which provides technical consultancy, research, testing, and program management services.*

Calum graduated with a degree in Mechanical Engineering from the University of Dundee and has been at NEL since 2008. Since then he has gained experience in a number of technical areas including flowmetering, measurement uncertainty, allocation, valves and erosion.

Reaching 20K

GE's new 20,000psi-rated BOP recently secured a contract with Maersk Drilling as part of BP's own Project 20K program. Jerry Lee reports on the new BOP and its control system.

Completed GE BOP stack. All images from GE.

GE BOP for transit.

Project 20K, initiated by BP in 2012, aims at developing the technology necessary to explore and produce from deepwater reservoirs that have up to 20,000psi of pressure and temperature up to 350°F at the seabed.

"Project 20K technologies will be key to safely unlocking the next frontier of deepwater resources in the Gulf of Mexico and beyond," says Stuart Rettie, project general manager for Project 20K. In 2013, BP and Maersk Drilling signed a development contract to collaborate on the conceptual designs for the drilling rig.

From 2012 to 2035, BP predicts an increase in global energy consumption by 41%, Rettie says. Subsea production is one method by which the rise in energy demand is being addressed. However, with current technology, there are vast deepwater reservoirs that are out of reach. As a result, industry must provide the research and engineering to develop the equipment that can turn those reservoirs into reserves. As a technology company, it is natural that BP would take up this challenge, Rettie says.

Observing similar trends, Shell Scenarios devised two possible forms that describe how businesses and governments may respond: Scramble and Blueprints; Scramble – energy security is sought by businesses and governments without regard to sustainability or the environment; Blueprints – businesses and governments cooperate to identify and address future issues sooner rather than allowing the problem exacerbate. With the development of Project 20K, it seems that the Blueprints scenario anticipates BP's decision to hedge their investment on early preparation.

Enlisting participation from other industry players, Maersk Drilling was selected to help develop the Project 20K drilling unit. In the scope of a drilling contractor package, there is a match in terms of technology, people, and safety and management systems, says Frederik Smidth, chief technical officer at Maersk Drilling.

When targeting areas of the Paleogene play in of the GOM, reservoirs can be expected that create pressures of 20,000psi and temperatures up to 350°F at the seabed where the subsea production trees are located. With current technology limited to a working pressures of 15,000psi, development of the 20,000psi system is sensible, "This is a natural evolution of offshore technology and a logical next step for industry," says Mick Leary, BP wells director for Project 20K.

A vital piece of equipment, whose development has seen recent success, is the blowout preventer (BOP). At the 2014 Offshore Technology Conference, GE Oil & Gas debuted its prototype deepwater 20,000psi-rated BOP.

With multiple companies developing designs for 20,000psi-rated BOPs, a number of considerations had to be made. In the end, GE was selected based on their familiarity with BP and Maersk Drilling's requirements for safety features and control systems, commercial aspects, delivery and availability of additional stacks, and total cost of ownership, Smidth says. As a result, GE received an order for four of the new BOPs and two new risers to be delivered by 2018.

The development of the 20,000psi prototype brings together technology from multiple industries for use offshore. These technologies enable the BOP to handle the additional 5000psi and increased temperature associated with production from that depth. As a piece of a multi-billion dollar investment, it is imperative to utilize proven technology.

"Everything on the system is a utilization of existing technology to handle the higher pressure," says Anthony Spinler, product manager for GE Oil & Gas. "We brought in technologies from other parts of GE and advanced the ones we already have to meet the higher pressure, and to make the risk level of the new system as low as possible. The best way to manage technology is to not invent too many things."

The primary advances are with the pressure maintaining components. As a safety and control mechanism, the BOP must be able to shear the pipe and casing strings completely. This means the hydraulic cylinders must provide enough force to the rams to operate properly, yet still not damage the BOP. The additional wellbore pressure at 20,000psi applies additional force these cylinders must overcome before they can cut pipe or casing. Thus the working conditions necessitated an upgrade to the body, bonnet, and hydraulic cylinders on the prototype. These components are made bigger to handle more pressure, and that keeps the risk down in the industry, Spinler says.

However, the task of producing from a deepwater well is not accomplished by simply making things bigger. Being so far removed from the well head, engineers had to come up with a model that allows operations to be more efficient in order to make producing deepwater fields economic. One method of improving efficiency is in innovating the BOP control systems.

One inefficiency can be equipment breakdown. When equipment breaks on a rig, operation must be shut down, and the broken equipment must be removed and replaced, resulting in non-productive time (NPT) which costs the company money. In deepwater subsea wells, NPT is compounded simply by the logistics of the operation; what may take an a few hours to replace on a normal rig can take days in subsea well, all the while costing the company money as well as making no progress. To mitigate NPT, the BOPs are designed to incorporate RamTel Plus sensors. Located inside the operator shaft, the sensor sends information regarding the ram position and exact pressure readings in the cylinder, allowing engineers to manage drilling operations and make real-time decisions on the health of the BOP operator.

To capitalize on the increasing amounts of data coming from sources like the

GE SeaONYX software.

GE 20,000psi BOP prototype

RamTel Plus sensors, the BOP control system will be managed by GE's SeaONYX surface control system. This electronic control system will send commands down to the BOP hydraulic control system to actuate the driller's commands.

SeaONYX is based upon GE's the Mark VIe hardware and software architecture, leveraging hardware that was developed for other GE applications into the BOP control space, says Bob Judge, director of product management for GE Oil & Gas. Using Mark VIe architecture benefits the customer by using a standardized set of control hardware and software, as well as offering a large lifecycle support network, Judge adds.

SeaONYX has many capabilities, such as real-time control of complex systems, however, its primary role for the BOP control system is to turn functions on and off and provide a historian database. Only about 2% of the capability of the controllers in the SeaONYX package is used, which Judge says is perfect for the application. GE is taking advantage of the robustness of the package to hedge for future needs. In combination with the SeaONYX system, GE will utilize newly introduced SeaLytics BOP Advisor software. By pairing the systems, SeaLytics can use the historian to provide the driller with valuable information using its predictive analytics; turning "dark data" into actionable information. SeaLytics can extract, from the raw data, information to track equipment performance, identify areas of operational decline, and plan for equipment maintenance, this result in less NPT, greater operational efficiency, and improved reliability.

"Every manufacturer is thinking 'how do I reduce these unplanned stack pulls, these unplanned problems,' this is GE's answer to that," says Cameron Wallace, communications leader for GE Oil & Gas' drilling systems group.

Inclusion of both the SeaONYX and SeaLytics systems allows the control system to adapt as the project progresses and becomes more complex. The architecture forms an expandable platform so that as more knowledge is gained, more prognostics or advisory capabilities can be added through SeaLytics or if the industry or regulators decide there is a need to automate some function, those options are already built in, Judge says.

With the introduction of GE's 20,000psi BOP prototype, and the inclusion of the SeaONYX and SeaLytics systems, BP is one step closer to being capable of producing from 20,000psi reservoirs. Reiterating BP's commitment to progressing the development of a 20,000psi capable system, BP will collaborate with Anadarko in a joint development agreement for Anadarko's Project 20A; Project 20A similarly aims to develop subsea facility designs. These projects may hasten the realization of a 20,000psi system and satiation of future global energy demand. OE

Electrifying tube bending

A CNC (computer numerical control) tube bending machine with advanced programmability is helping Siemens Subsea Products to improve the precision and production efficiency of subsea hydraulic components and systems. Steve Hadrell explains.

Hydraulic distribution, connection and control systems, for subsea use with equipment such as wellhead trees, have very demanding tube fabrication requirements, not dissimilar to those of the aerospace industry.

Much of this equipment is intended for operation at depths to 3000m and beyond, which means the tubes can be subjected to extreme internal and external pressures, and has a design life of 30 years or more. Common requirements include use of costly corrosion resistant alloys, the need to form complex precision bends with tight process control, to prevent mechanical stresses that would seriously impair the tubing's strength, and very small production batch sizes – which demand considerable tooling changeover flexibility and exceptionally high standard manufacturing.

Such demands can lead manufacturers to outsource tube production to specialist third-party tube bending companies.

Siemens Subsea Products recently chose a different strategy for small bore tube manufacturing. The firm produces a diverse range of electrical and hydraulic power and control systems, as well as fiber-optic communications connectors, for subsea applications. Many of these products reply on small-bore metal tubing to convey hydraulic fluid for power and control purposes. Typical examples include hydraulic flying leads with multiple quick connections, subsea distribution units and the Bennex Anguila range of cobra heads, used to terminate hydraulic and electrical umbilicals on subsea equipment.

Until last year, Siemens Subsea Products fabricated some of the tubes for these products in-house, using manual bending techniques, but met about 50-60% of its needs using bought-in preformed parts. The tubes' dimensions and properties depend on the application, but they are typically 1-3m-long, with outside diameters from 3/8in. to 5/8in. and have a 3mm wall thickness. Many are manufactured from extremely hard alloys, such as Inconel and Duplex/Super Duplex stainless steel – materials which are extremely difficult or even impossible to bend by hand.

Bennex Anguila cobra heads can contain up to 13 precision-bent hydraulic tubes. Photos from Unison.

In 2013, to improve production efficiency, the company equipped its hydraulic workshop at Kongsberg in Norway with a Unison all-electric tube bending machine. It chose all-electric servo-motor-based movement instead of traditional hydraulically powered technology because this offered more accurate and repeatable results, lower energy consumption and lower noise. Fast tool changeover was also important – many of the tubes are produced in very small batch sizes. Unison was able to develop a machine configuration specifically for Siemens.

The tube bender is a 25mm model based on Unison's Breeze platform of all-electric machines, with "rise and fall" pressure dies, which allows it to perform right- and left-handed bending. This increases manufacturing efficiency by allowing tubes up to 6m in length with multiple complex precision bends to be produced in one continuous machine cycle. Previously, manual bending required repeatedly inserting each tube into various forming dies and required a minimum space between bends of 20mm to allow for clamping; this is reduced to just 5mm on the bending machine, allowing Siemens to create parts that are optimized for space-constrained applications much more easily.

Storm Trosdahl, Product Specialist for hydraulic distribution systems at Siemens Subsea Products, says: "For applications such as our cobra heads, where we are packing up to 13 hydraulic lines in a very confined space, we necessarily have to use some small radii tube bends, with precision control over the bending process to avoid stressing the material. This was difficult to achieve manually, but the Unison machine allows us to apply constant torque throughout the bending process, while also controlling the rate of bending. This makes it easy to control the resultant changes in the material. Also, of course, it has sufficient torque to handle all our requirements, including bending tubes made from Inconel (a type of alloy) – which we previously always had to contract out."

The first project to use the machine was the production of 800 tubes for hydraulic flying leads intended for deployment in Indonesia's South Belut gas field in the South Natuna Sea, involving an eight-well

Siemens Subsea Products' hydraulic workshop in Norway uses this Unison tube bender for all small-bore tube fabrication.

subsea tieback to a central processing platform in the North Belut gas field. Each tube is manufactured from 316 stainless steel and required as many as six complex bends, followed by orbital welding at both ends. There were eight different tube configurations, and all 800 were produced to exactly the right dimensions, with no wastage. The next major use of the bending machine was producing tubes for cobra heads destined for the Greater Plutonio project in offshore Angola, where the equipment will be used at depths of 1600m.

All critical movement axes on the Unison tube bender are driven by software-controlled servomotors, providing fully automated set-up, that allows fast and repeatable fabrication of parts with accuracies to within fractions of a millimeter. This programmability and repeatability are key to Siemens Subsea Products' manufacturing strategy. Instead of using drawings to convey requirements for manual tube bending, the company now designs every tube on an Inventor 3D computer aided design system that is networked to the bending machine. After producing a prototype and verifying its accuracy, any necessary corrections are fed back into the process to ensure that all subsequent parts are manufactured to the same consistent quality. This has resulted in a significant reduction in expensive material scrap; with manual bending, the company was losing about 6m of tube per week to trial parts and production errors – the figure is now typically about 0.5m per week.

The tube bending machine undergoing final commissioning checks at Unison's UK manufacturing facility, prior to shipment.

Siemens Subsea Products now produces all its tube parts in-house. Instead of requiring five people with specialist fabrication skills to produce 40% of the tubes that it needs, it now takes just one machine operator to satisfy all production requirements. Automating the bending process has also reduced production costs. Siemens originally estimated a machine payback period of slightly less than two years – in itself a good figure – based on a typical £100/part cost for third-party bending. The machine has paid for itself in half this time.

Over the past year, Siemens Subsea Products has also produced hydraulic flying leads for a number of smaller projects, such as Ithaca Energy's Stella oil field in the North Sea, which is currently under development, as well as undertaking specialist tube bending work for several third-party subsea equipment manufacturers. OE

***Steve Haddrell** has served as key accounts manager for Unison since 2009. Prior to that, he was UK branch manager for the Optonics division of machine tool manufacturer Yamazaki Mazak. Hadrell has also worked in senior sales management and technical support roles for a number of other machine tool manufacturers, including Kerf Developments and the 600 Group.*

North Sea mooring systems: How reliable are they?

Mooring failure rates are still higher than industry targets. Assessing past failures could help industry understanding, say Will Brindley and Andrew Cornley.

The *Blackford Dolphin* semisubmersible mobile offshore drilling unit Images from DNV GL.

In recent years, a number of high-profile mooring failures have emphasized the high risk nature of this element of a floating structure. The fleet of semisubmersible mobile offshore drilling units (MODU) operating in the harsh North Sea environment has experienced approximately three mooring failures every two years. In recognition of the high mooring failure rates, the UK's Health and Safety Executive (HSE) has introduced recommendations for more stringent mooring strength requirements for units operating on the UK Continental Shelf (UKCS).

An investigation by DNV GL compared UKCS mooring failure rates with industry code targets and Norwegian Continental Shelf (NCS) failure rates to understand how overall reliability is related to the strength capacity of a mooring system. This investigation found that although strength requirements are useful to assess the suitability of a mooring design, they do not provide an insight into the true reliability of said system. Indeed, increasing mooring strength capacity alone may not lead to the increase in reliability that the regulators desire and the industry needs. Instead, focus should be on the less tangible aspects of the entire mooring process, from component selection to operation.

Failure Statistics

Failure statistics, as summarized in Table 1, suggest that a typical MODU operating in the UKCS will experience a mooring line failure in heavy weather every 24 operating years. This failure rate appears to be several orders of magnitude greater than industry targets used to calibrate mooring codes. DNV GL's mooring Offshore Standard E301, for instance, has been calibrated to give a target single line failure rate of once every 10,000 operating years and a target multi-line failure rate of once every 100,000 years. Due to known under-reporting, the actual failure rate is likely to be higher, especially as mooring failures in calm weather and during anchor handling have been excluded from the statistical analysis, as the consequences of such failures are likely to be limited.

Table 1: **MODU Mooring Failure Rate Comparison**

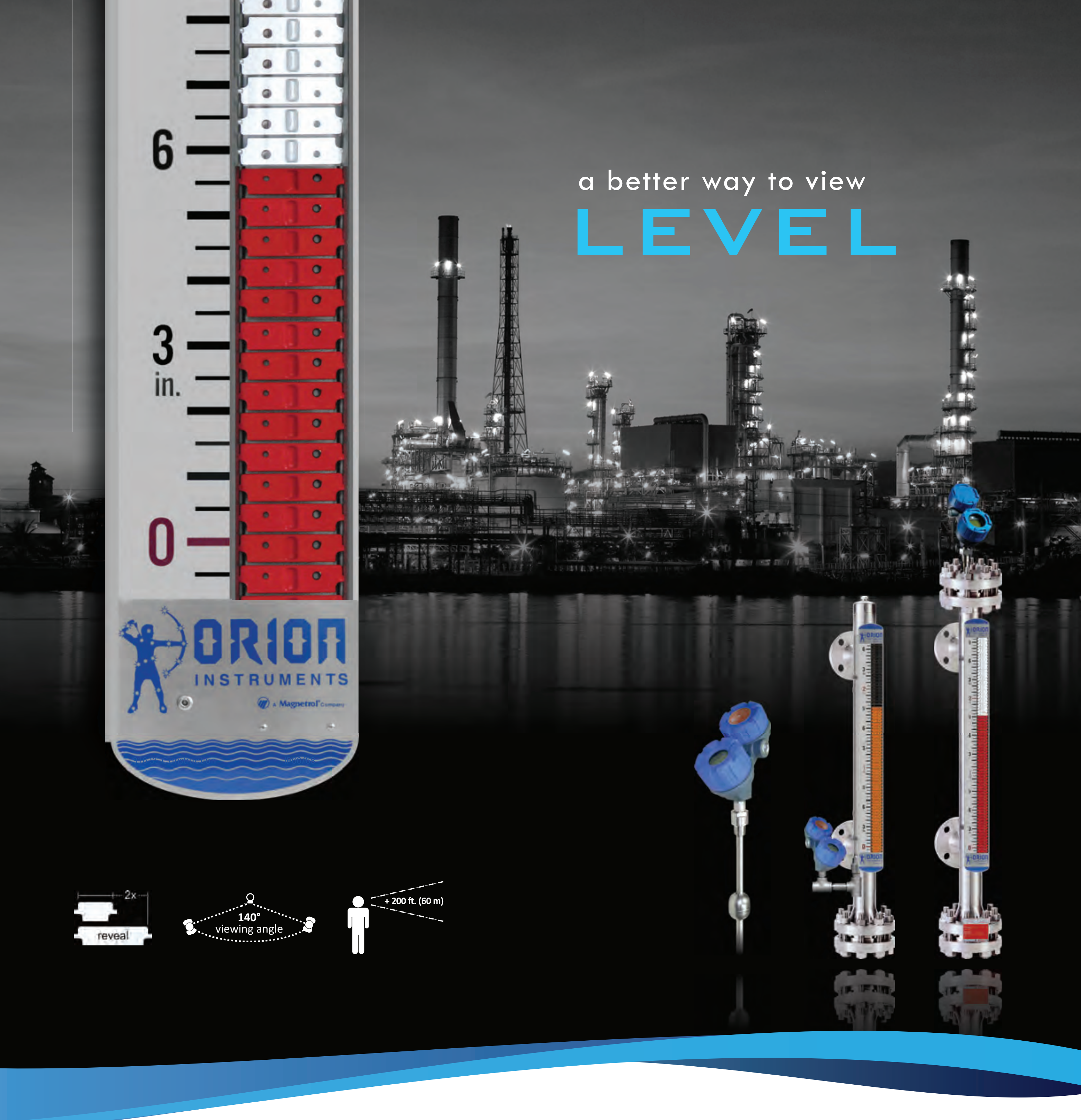
Reliability measure	Unit operating years per failure	
	Single line failure	Multi line failure
Code calibrated	10 000	100 000
Recorded statistics*	24	112

* MODU Mooring Failures in Heavy Weather: 1996-2005

A typical chain link.

Two-thirds of the multi-line failure events resulted in significant consequences including; subsea infrastructure damage, vessel grounding and hydrocarbon release. Although no major incidents have occurred to date, the potential is high for severe subsea asset damage and hydrocarbon release, especially when drilling in an existing development.

MODU mooring component failures are generally not well understood or controlled and have the potential to lead to a catastrophe.



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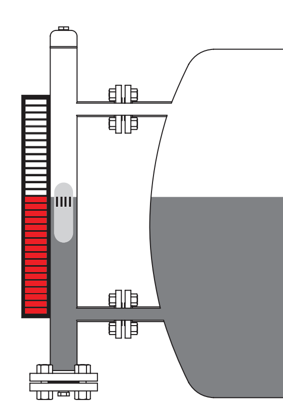

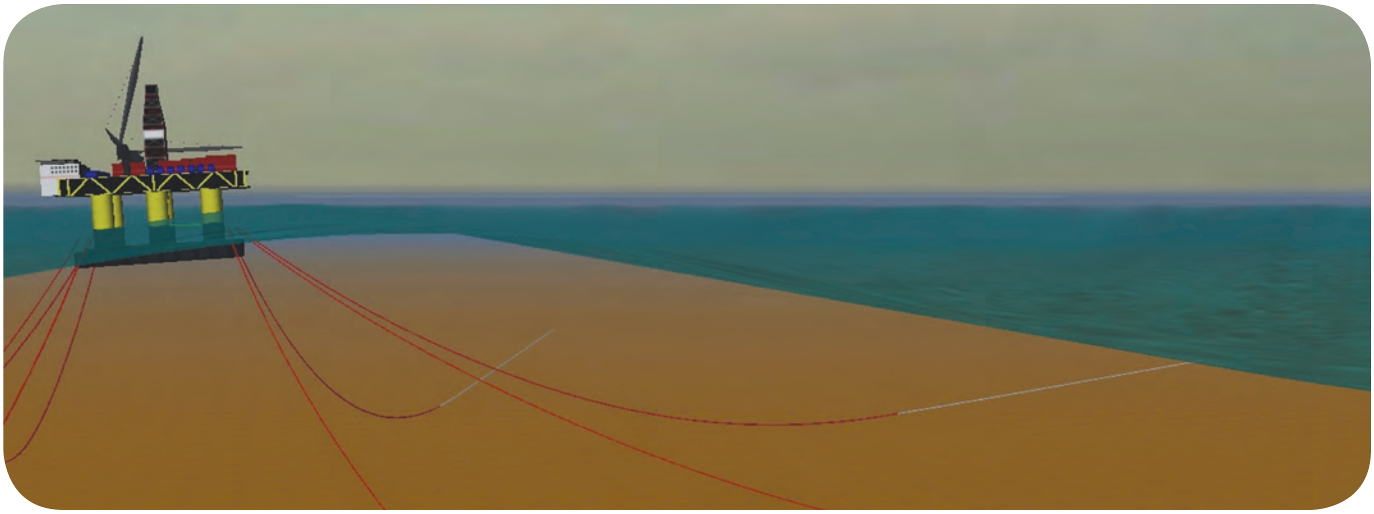

Fig. 1: OrcaFlex mooring analysis model.

Recent UK HSE mooring regulation

In recognition of the high mooring failure rates, the HSE has introduced recommendations for more stringent mooring strength requirements for units operating on the UKCS. Although the HSE's recommendations are subject to interpretation, it is understood that the spirit is for alignment with the Norwegian Maritime Directorate requirements for operation on the NCS. The emphasis of the enhanced requirements for MODUs is on increased strength safety factors.

The impact of the HSE's recommendations on the required mooring equipment for a typical MODU has been evaluated. To achieve this, a mooring analysis model was developed using the time domain analysis package OrcaFlex, illustrated in Fig. 1. A typical North Sea Aker-H3 MODU with an eight-line mooring system composed of 76mm Grade R4 chain was assessed. The strength assessment found that an increase in chain diameter or an increased number of mooring lines would be required to meet the HSE recommendations for the most severe North Sea locations.

For most existing MODUs, this would require prohibitively expensive modifications to the vessel structure. Intermediate options are available for more benign North Sea locations, to meet the enhanced code requirements, without significant changes to vessel equipment.

Table 2 summarizes the code compliance of comparative intact mooring systems. It should be noted that the results presented in this table are representative only, as code compliance will be dependent on water depth, vessel design, mooring system properties, environmental conditions, and the analysis package used.

The comparison of maximum versus allowable mooring line tensions is useful to assess code compliance; however, it still does not answer the question: How does increased strength capacity influence the overall reliability of the mooring system.

Table 2: **Intact Mooring System Code Compliance**

Mooring system	ISO 19901-7		NMD No 998	
	Central North Sea	Northern North Sea	Central North Sea	Northern North Sea
76mm grade R4 chain	✓	✓*	✘	✘
76mm grade R5 chain	✓	✓	✘	✘
Fibre rope insert	✓	✓	✓	✘
Heavy chain insert	✓	✓	✓	✘
12 line 76mm R4 chain	✓	✓	✓	✓
87mm grade R4 chain	✓	✓	✓	✓

* Assuming mooring not in close proximity to other installations

Impact of code requirements on reliability

Mooring code requirements have changed over time, but the strength requirements for the NCS have remained proportionally above those for the UKCS. If the recorded failures are correlated with strength capacity, then the failure rate for the NCS should logically be significantly less than that for the UKCS.

Mooring failure data reported by the Norwegian Petroleum Directorate from 1996 to 2013 indicates that even with the higher strength requirements, the failure rate remains at a rate similar to that of the UKCS, for both single- and multiple-line failure. This suggests that reliability does not correlate well with mooring system strength capacity. As a result, designing mooring systems to meet more rigorous HSE requirements may not give the significant increase in mooring system reliability that the industry needs.

Historically, most attention has been focused on strength, perhaps because it is the most tangible failure mechanism. Strength overload though, is but one of a large number of mechanisms that can result in mooring failure, with the statistics suggesting that it these other failure mechanisms that are dominating reliability. Therefore, the industry needs take a wider view of all aspects of moorings to improve reliability.

Improving reliability

Current understanding of past failures indicates closer attention to the following practical aspects may significantly improve MODU mooring reliability:

- Optimizing mooring system design by selecting components with proven reliability and ensuring components are compatible;

- Closer attention to the manufacture, selection, traceability, and loading history of all mooring equipment, both owner and rental;
- Enhancing inspection and maintenance requirements for mooring equipment;
- Verifying actual vessel response against theory, including the impact of any modifications, and;
- Adequately calibrating and testing winch load cells and thrusters.

Work remains to be done to perform a wider and more detailed investigation of historical North Sea failures and their root causes, in order to identify areas where attention can best be focused to improve reliability. This could be more readily performed if all failures were openly reported and investigated by operators.

Conclusions

The failure statistics for MODU mooring systems indicate a mooring line failure would be expected to occur on average every 24 rig years and a multiple-line failure around every 112 rig years. This failure rate appears to be several orders of magnitude greater than industry targets used to calibrate mooring codes.

The assumption that increasing safety factors will improve reliability is contradicted by the actual failure rate in the NCS, which does not show a proportional increase in reliability despite the significantly increased mooring system strength requirements.

Work still remains though to find practical ways to improve reliability. An increased focus on improving understanding of past failures is probably the most opportune method to improve mooring system reliability. OE

__Will Brindley__ joined DNV GL after graduating in 2011 with a Master's of engineering in naval architecture and ocean engineering from the University of Strathclyde. Brindley's studies were punctuated by placements at the Samsung Heavy Industries shipyard design office and the Intelligent Engineering composite structures analysis team. Since joining DNV GL he has worked on naval architecture advisory projects including mooring design and updating the Oil and Gas UK Mooring Integrity Guidance.

__Andrew Comley__ is a consultant with DNV GL providing specialized integrity and incident investigation services, recommenced his association with the company in 2008 as the Mooring Integrity Phase 2 JIP project engineer. Previously he has worked for Steel-kit, Kingfisher Marine Services, Noble Denton, UK HSE and Advantica. He gained a Bachelor's degree in naval architecture and shipbuilding from Newcastle University in 1994 before undertaking Lagrangian computational fluid dynamics research at Glasgow University.

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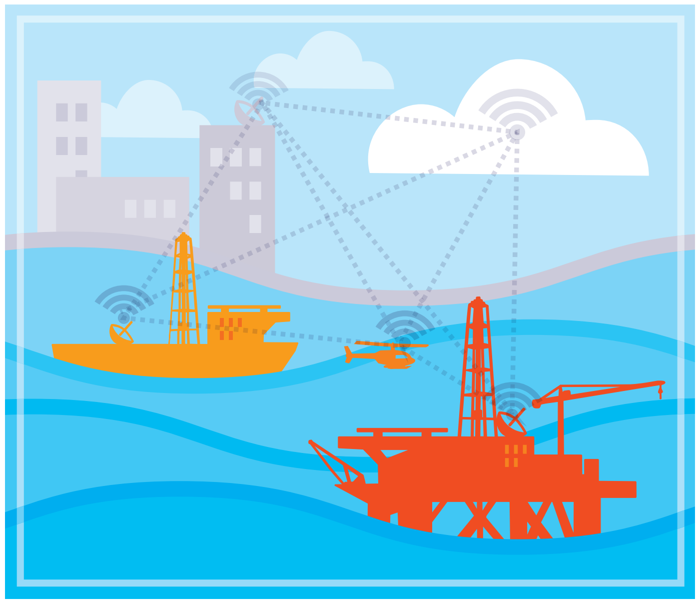
Faster than real time

Gregory Hale explains why real-time data transfer doesn't always cut it in the offshore oil and gas environment.

Real-time information is not enough anymore. When a compressor was showing signs of possible overload, a team of engineers watching the data noticed some subtle, but potentially troubling, signs at Chevron's Machinery Support Center (MSC) in Houston, 7000mi from its Sanha field off the coast of Angola.



Operators on platforms need to know what is going to happen before things start to unfold. It sounds like magic, but it is an issue of knowing the system and understanding key data points.

"Real-time isn't good anymore. Right now, especially in oil and gas, the easy to operate wells as a percentage are diminishing," said Stan DeVries, senior director - solutions architecture at Schneider Electric. "If I am an expert because of my experience, I am on the beach. If somebody with less experience needs my help, by the time they contact me it is too late for me to help, then it is useless. I can't just have real-time of what is in front of the hood, I need the GPS view of what is happening around the corner," DeVries said.

The crew working at Chevron's facility on-site may or may not have found the issue in time, but having the back up watching the data saved the company millions in lost uptime.

"The crew acted on the MSC's tip and avoided a couple of million dollars in downtime and lost production," said Fred Schleich, machinery and electrical power system manager at Chevron, in Chevron's *Next* technology magazine.

The future is here

"This is not 'Star Wars,' there is a lot we have put together, it has to be baked into transforming the work," DeVries said. "Especially with wells with smaller reservoirs. There is not an underground lake anymore."

Smaller wells having a shorter lifespan and are harder to operate. If the operator has to interrupt the flow, there is a higher potential for things to go wrong quickly. Information needs to get to the proper personnel as soon as possible.

"I talk about only the right information and only the right context in only the right time – which could be ahead of real-time – to the right person," he said. "Shell calls that bringing the work to the worker. Once the work comes to me, I want to browse around and discover patterns the software can't figure out. That is a transformation of information to support the transformation of work."

That transformation, as DeVries calls it, is the cornerstone of how to manage information so managers and planners have access to comprehensive performance data to assess and capitalize on opportunities.

"We are seeing a much higher demand for information transport from the offshore environment to an onshore location of some kind," said John Gilmore, director of global application consulting at Schneider Electric. "Early drivers were Macondo, where they had a four-hour gap in information from when the last data set was sent from the drillship until the incident. There are now people saying we have to ship data more frequently and even in real-time."

While that data would not have saved *Deepwater Horizon*, getting that information over to the experts would have told them much quicker about what happened.

"The bulk of the data went down with the vessel," Gilmore said. "There are a lot of people saying they want real-time data now."

Reducing staff for safety, costs

Reacting and developing plans off a disaster is one thing, but another emerging trend is the idea of automation reducing staff levels offshore. That not only allows for automation to offer increased levels of process control, but it also becomes safety and cost factors.

"It is a combination of business process design and then data system enhancement, in particular bandwidth, in getting the data to the beach," Gilmore said. "What I have seen so far is yes, we can do the data, but we don't necessarily eliminate things until we look at the business organization or the clerical staffing."

That is also where the cost factor comes into play.

"The number I hear is US$5,000 to $10,000 a week in costs per person," Gilmore says. "There is a manual checking and rechecking verification process that we will probably never eliminate, but right now that is a little bit of three or four guys' jobs. Can we restructure the business process where we have one guy that does a lot of data checking and the other three can be on the beach?"

"You are trying to do the work better, you can throw technology at it or the people, but you change the work. That can be very disruptive for people and that means organizational change management is required," DeVries says.

There is no doubt that having people,

process and technology all working in sync ends up being the Holy Grail in the automation environment offshore. With fewer workers, that means technology needs to improve so workers can make informed decisions.

One example is a heat exchanger. "When a heat exchanger starts out clean as you possibly can get it, you don't expect to take it out of service for up to five years," DeVries says. "Today's technology keeps calculating efficiency; you can do that every hour or every day. You can connect that information with some relatively simple calculations and say that well will only last so long and the heat exchanger will last only so long to a threshold. It is not an alarm, but it is a trigger for decisions. So the decision may be we can live to fight another day. We are making a production target and we will take the hit and we will move on when the well completes. We can work together and make the decision on scheduling on what we can do to operate less severely."

Consolidating technology

All that data needs to pass along to command centers onshore, like the Chevron MSC, and to the executive suite. Users now want to bring everything under one roof.

Centralization of data and the ability to relate different sources into a single place is a driving force offshore, Gilmore says.

"Historically, we have had a marine control system, which runs the bottom and reports relatively little information to the topside crew. Now we are seeing the trend that says I want all the data in one place. I want to manage my entire vessel from one window," Gilmore says. "Yes, the topside may have different control and different operators assigned but I want the data together so inferences can be made and responses made. We are seeing integration of the hull systems, ballast management, mooring management, they want propulsion DP, all of those integrated into that system as well. They also want to integrate the hotel, everything about the people, HVAC, even food management. The driver is not only to reduce the amount of equipment by centralizing stuff, but it is also driver to get the data to do the analysis, and to get the data to the beach."

Getting the information for the "C-level and for technology knowledge workers has been around since 1995," DeVries says. While some of the technology has evolved, the idea and the method have remained constant. But, DeVries adds, only a few users are communicating enterprise wide. That could mean users have the potential to reap benefits once they start employing a complete automation program.

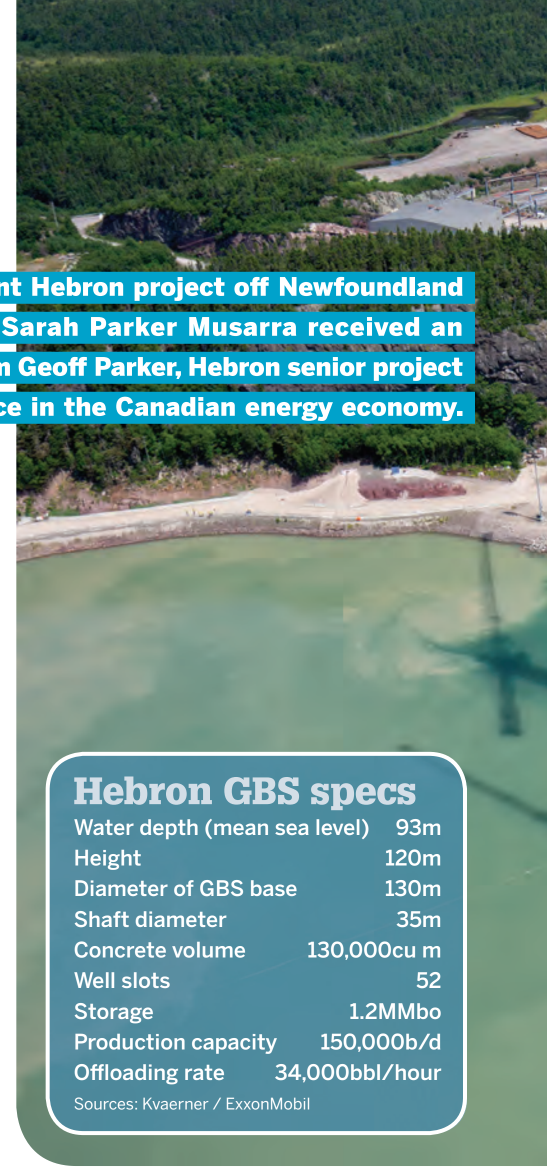
DeVries explains: "42% of errors that lead to unplanned shutdowns are caused by people, and that is from experienced workers. What would the number be with less experienced worker?"

Whether it is about a shortage of workers or embracing new technologies, to grow and hike productivity to become more profitable, users now have to manage information to understand performance data and to jump on opportunities faster and more intelligently – before real-time. OE

***Gregory Hale** is the Editor and Founder of Industrial Safety and Security Source (ISSSource.com) and is the Contributing Automation Editor at Offshore Engineer.*

Betting on Hebron

First oil from ExxonMobil's giant Hebron project off Newfoundland and Labrador is set for 2017. Sarah Parker Musarra received an update on the development from Geoff Parker, Hebron senior project manager, and examines its place in the Canadian energy economy.



Hebron GBS specs

Water depth (mean sea level)	93m
Height	120m
Diameter of GBS base	130m
Shaft diameter	35m
Concrete volume	130,000cu m
Well slots	52
Storage	1.2MMbo
Production capacity	150,000b/d
Offloading rate	34,000bbl/hour

Sources: Kvaerner / ExxonMobil

After its 1980 discovery, the giant ExxonMobil Canada-operated Hebron field is getting its sea legs. With first oil planned for 2017, Hebron will then become the fourth field producing in the frigid waters of the Canadian province of Newfoundland and Labrador.

Hebron is a heavy, 20°API crude oil project located in the Jeanne d'Arc basin about 350km southeast of the capital St. John's, in water depths ranging from 88 to 102m. According to the project's development plan, the asset currently contains three fields discovered in the early 1980s: Hebron, West Ben Nevis, and Ben Nevis, which housed Hebron's initial oil discovery. These fields span four significant discovery licenses: Hebron SDL 1006, Hebron SDL 1007, Ben Nevis SDL 1009 and West Ben Nevis SDL 1010.

Hebron will tap four reservoir intervals, which are structured into several normal fault-bounded fault blocks. The four reservoirs, which are vertically stacked with multiple fault blocks, are the Late Jurassic Jeanne d'Arc formation, the Early Cretaceous Hibernia formation, the Early Cretaceous Avalon formation and Early Cretaceous Ben Nevis formation.

ExxonMobil Canada Properties operates Hebron with 36% interest. Its partners on the development include Chevron Canada Ltd. (26.7%), Suncor Energy Inc. (22.7%), Statoil Canada (9.7%) and Nalcor Energy (4.9%). ExxonMobil assumed the operatorship from Chevron in 2008, and announced its intent to develop the field using a gravity based structure (GBS) in January 2013. At that time, the supermajor revealed that by using the GBS it will be able to recover more than 700MMbo, up from earlier estimates of 400MMbbl, from Hebron.

Developing a field estimated to produce such volume comes at a price, and Hebron's cost is approximately US$14 billion, following the increase in recoverable reserves.

"This is expected to be the most capital-intensive fixed platform development globally for 2015," says Catarina Podevyn, published content analyst for energy analyst firm Infield Systems.

Hebron is not just the most capital-intensive project globally: This is also true for the Arctic region over the next five years, Podevyn says. "It will form 41% of the region's capital expenditure for 2015," she says.

Hibernia to Hebron

The unrelentingly harsh environment off Newfoundland and Labrador is among the world's most severe. During the province's brutal winter months of November through March, Newfoundland and Labrador's tourism board places the high temperature range between 1 and -8°C and the low range between -6 and -18°C.

These extreme meteorological and oceanographic conditions would stand to dictate the field's development plan. ExxonMobil has extensive experience operating in Arctic environments, but some of its most applicable experience to the Hebron field was in the project's own backyard: Hibernia. Many lessons have been gleaned from the long-producing field.

"We had the benefit of having developed Hibernia in the 1990s and applied learnings from that project, as well as several other GBS projects we have executed since Hibernia. We have paid special attention to the constructability of the GBS design, and have configured the GBS taking into account the latest technical developments in wave and ice loading," Hebron Senior Project Manager Geoff Parker says, pointing to the offshore loading system (OLS) as one example. "Hibernia had a system that was replaced recently because the components in this harsh environment can be subject to fatigue. Hebron will use a system similar to the new system installed on Hibernia," he says.

Hebron's OLS is a closed loop design; two main pipelines will run from the GBS to two separate riser bases. The design allows for round-trip intelligent pigging and flushing operations through the pipelines and pipeline end manifold if an iceberg threatens the loading facilities.

Production and Hebron's GBS

Like Hibernia, Hebron will produce through a GBS, which has an in-service design life of at least 50 years.

Engineered and constructed by Kiewit-Kvaerner Contractors, a joint partnership between Peter Kiewit Infrastructure and Kvaerner Newfoundland as part of an overall engineering, procurement, installation and construction contract for the development, the reinforced concrete-GBS has 52 well slots and is capable of operating in an average water depth of 93m. It has production capacity of 150,000b/d and is capable of storing around 1.2MMbo.

The environment remains a constant issue to contend with. Two different forms of floating ice – sea ice and icebergs – are present in Hebron's offshore marine environment, Parker says.

He explains that parts of nearshore construction at Bull Arm, such as major concreting work, was done outside of the winter months. The GBS will remain floating during parts of the construction and installation phases, so stability is critical even when construction is suspended

Expected to begin producing in 2017, the ExxonMobil-operated Hebron project will be the fourth project operating off Newfoundland and Labrador. It is close to its neighboring fields: 9km north of Terra Nova, 32km southeast of Exxon's Hibernia, and 46km southwest of White Rose. Photos from ExxonMobil Canada Properties.

temporarily. The GBS' unique design is, he explains, a function of the various construction stages as well as the production phase.

"The GBS is designed to withstand impact from both sea ice as well as icebergs. Nevertheless, once the platform is installed offshore, Hebron will participate in an existing ice management program which monitors both sea ice (pack ice) and icebergs," Parker says. "Individual icebergs are identified and tracked by aircraft and platform radar from considerable distance away from the platform. If an iceberg's drift path is likely to intersect with the platform, the iceberg is diverted by towing or, for smaller icebergs, using vessel fire-fighting cannon or propeller wash to re-direct it. Sea ice is monitored for information to vessels supporting the platform, such as supply vessels.

Parker says that the team ruled out an alternate plans including subsea wells tied back to the Hibernia platform; an FPSO in combination with subsea wellheads; and an FPSO in combination with wellhead gravity base structure.

"An extensive process was undertaken to review alternative development concepts for the Hebron Project. The project proponents evaluated the alternative modes of development and determined that the preferred concept was to develop the Hebron asset using a stand-alone concrete GBS with oil storage, plus a topsides including processing and drilling facilities, and an OLS," he explains.

The development celebrated its most recent milestone on 23 July, when the GBS was towed from dry dock to its Bull Arm deepwater construction site. The 180,000-tonne structure arrived 10 hours after tow-out operations began. Construction began in dry dock during October 2012.

Since the towing, mooring lines have been attached to the structure, Parker says. After that was completed, the flotilla was put into place around the GBS to prepare for the next phase of construction. The concrete slipforming for the next construction phase started in September.

According to the project's development plan, the GBS' modular topsides, with a nominal design life of around 30 years, will include a drilling support module, a derrick equipment set, living quarters, a flare boom, and a utilities and processing module. One main shaft will support the topsides and encompass all wells.

The bigger picture

The US Energy Information Agency places Canada as the fifth greatest energy producer in the world; however, Atlantic Canada's production is all offshore, meaning that its energy economy is different from the rest of the country. And the forces driving that economy are aging, although continued drilling on satellite fields contribute to keeping production rates relatively stable. When it enters production, Hebron will be the newest producing project in the basin by a significant margin. Nestled within a cluster of long-producing crude fields – Exxon's Hibernia, Suncor's Terra Nova, and Husky Energy's White Rose – hopes are pinned on the Hebron field as the production from aging fields slowly dwindles.

Hibernia started up in 1997 through a GBS. Terra Nova and White Rose came online in 2002 and 2005, respectively, through floating production storage and offloading units (FPSO) units.

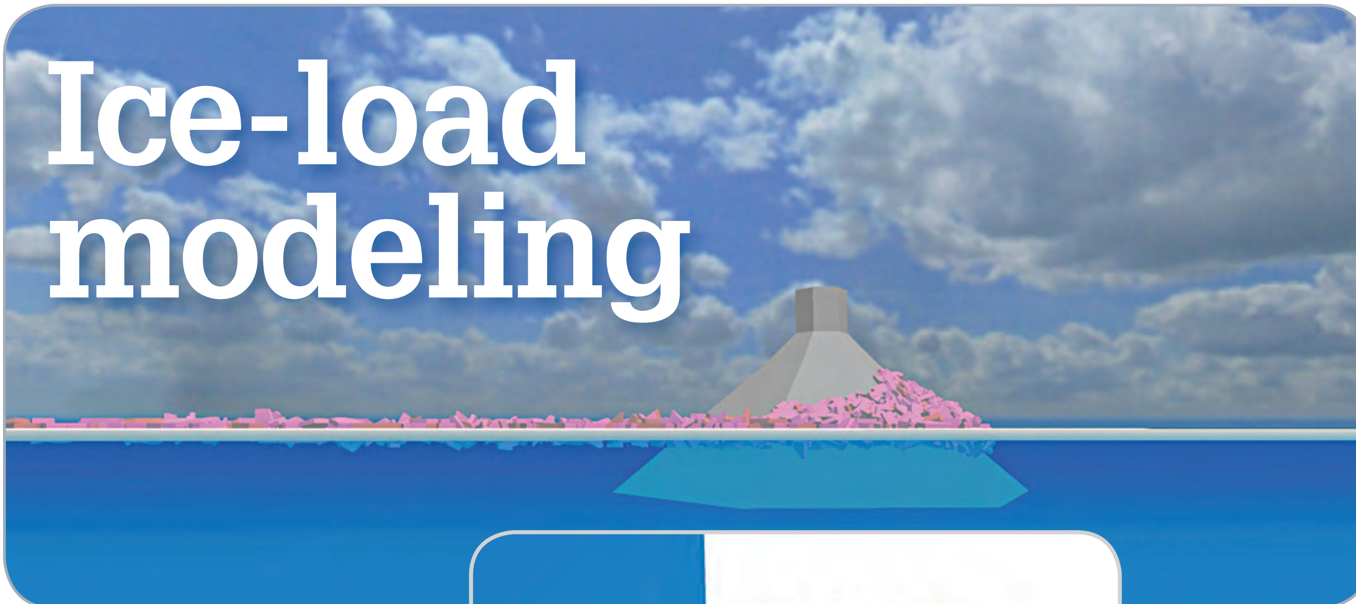
According to the Canadian Association of Petroleum Producers' (CAPP) June 2014 Crude Oil Forecast, the area's production is expected to hold at levels above 200,000b/d until 2024, with that rate supported by Hebron and the existing trio of assets' satellite fields. By 2030, it is expected to decline to less than 100,000b/d. CAPP notes on its website that that the currently producing facilities in Atlantic Canada have been in operation for a minimum of seven years, with some fields in production since the late 1990s, thus leading to a decling in production.

Annual production levels, also provided by the CAPP, show a peak in the Atlantic Provinces' production in 2007 at 381,000b/d. Production has fallen off significantly since then, with a decline almost every year.

According to the association, the area's production levels in 2013 clocked in at 231,000b/d.

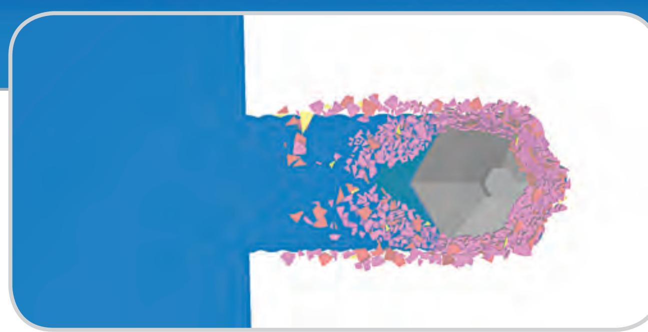
The news isn't all bad. According to Tom Ziegler is Vice President of Global MultiClient at Petroleum Geo- Services, the area offshore Newfoundland and Labrador contains an untapped potential with an estimated 6 billion bo and 60Tcf of natural gas yet to be discovered (OE: January 2014). **OE**

Ice-load modeling



Ice modeling conical structure side view.
Images from Bureau Veritas.

A multi-model approach is being used to take into account new phenomena and any number of structures, whatever their type, for ice-load modeling offshore. Philippe Cambos explains.



Ice modeling conical structure from above.

As energy exploitation pushes further into the Arctic regions more specific techniques are needed to understand the effect of ice movement on offshore structures.

There is a lot of experience with ice, but new structures in the high Arctic will demand structural optimization and design validation for very severe ice conditions where experience is more limited. Ice basin testing will take too long and is too expensive, so new tools are needed to speed the process and reduce the number of ice model tests.

International classification society Bureau Veritas (BV) has worked on the front-end engineering and design (FEED) for the Shtokman project (operated by Gazprom), and separately with Saint-Petersburg Technical Marine University, it has developed new software for direct analysis of hull structure strength for ships operating in ice. The tool, IceSTAR, has been used to assess the hull structure and cargo containment for the unique double-acting icebreaking LNG carriers, which will service the Yamal project (Novatek).

But, IceSTAR was built and validated for ships moving into ice, to help them develop safe navigation criteria. The behavior of the ice itself and the movement of the ice are less critical than the movement of the ship. For fixed or floating anchored structures the ice behavior is critical and further work was needed to model ice loads on offshore structures with the level of detail, precision and reliability needed. That work is ongoing, under a contract with Technip in cooperation with Cervval, a French specialist software company.

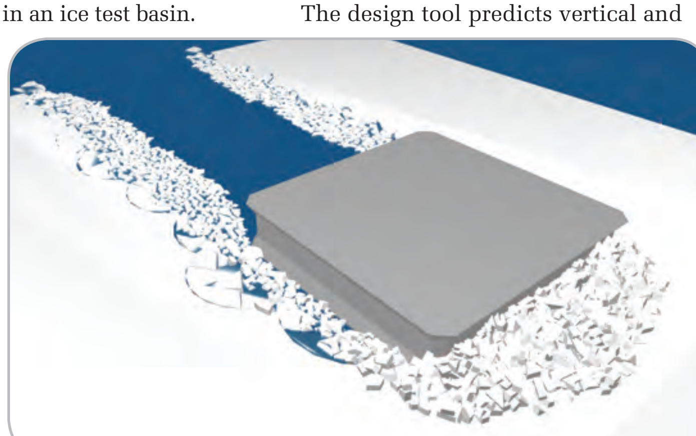
The aim is to develop a simulator to predict the flow of ice around both fixed and floating structures and calculate the ice loads on the structures. The program will ultimately allow platform structures to be optimized so as to minimize ice loadings and ice rubble build-up prior to final design verification in an ice test basin.

The first stage of the project is now complete and allows simulation of the flow of an ice sheet as it impacts on a conical structure. That was chosen as the first step to meet the specific needs of Technip's designs for use offshore Kazakhstan, in the shallow water and heavy ice conditions of the Caspian Sea. The program is also applicable to Arctic conditions and in the second stage, now ongoing, the software is being extended to cover ice interaction with a straight sloping wall structure. It will in the future cover vertical-walled fixed structures and a range of floating structures.

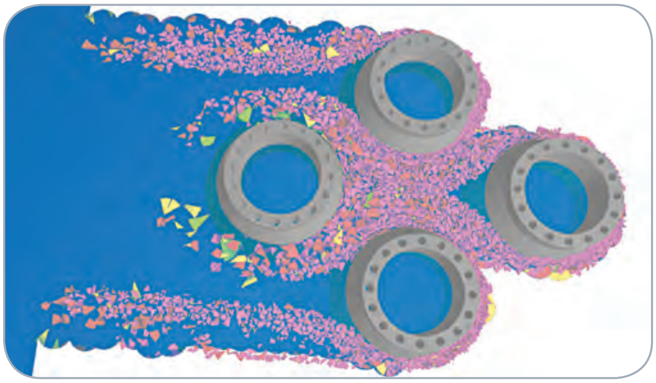
BV is providing Cervval ice expertise and verification during the software development process.

The program uses a multi-model simulator that copes with the complexity of calculating the kinematic and failure behavior for the ice sheet and for each ice fragment that results from contact with the structure or from collision with other ice rubble particles.

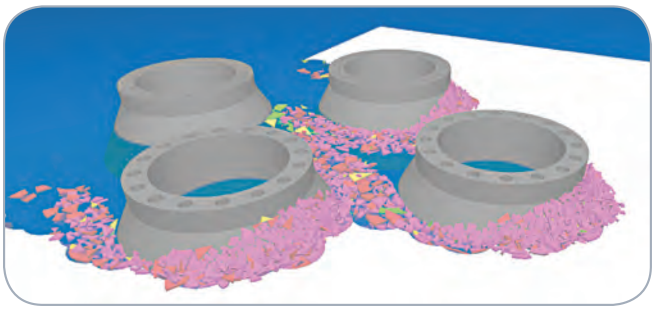
The design tool predicts vertical and



Ice modeling on square structure.



Ice modeling on multiple conical structure.



Ice modeling on multiple conical structure.

horizontal loads on the structure with accuracy. It also predicts the geometry of the ice accumulation in front of the structure, above and below the ice sheet.

Ice moving against a structure can fail by bending, crushing, splitting and shearing. A number of empirical methods based on ice model tests allow assessment of ice load components, but they require extrapolation of the model test results to full-scale conditions and suffer limitations if ice strength or the ice thickness differs from required values. They are also dependent on the structure shape used in the model tests, and cannot be extended to other types of structure.

BV and Cervval are combining knowledge of ice behavior from a number of sources in order to create a complete numerical simulator for ice design. The tool brings together several algorithms of different scales and behaviors, and simulates the structure, the level ice sheet, ice fragments, ice pile up, water and currents.

It starts with conical structures, as these are the preferred design geometry for Arctic applications. The simulation of ice behavior can be taken in two steps. First, the flexural cracks in the ice sheet and ice fragments are calculated, then the behavior of individual ice fragments and the sheet are modeled.

The simulation of ice loads on conical and sloping wall structures is based on ice failing in bending. Crushing and shear failure will be implemented for simulation of ice loads on vertical-walled structures. The effect of circumferential cracks formation on the ice load value is so small it can be safely neglected.

For the purposes of this simulator, the structure, ice fragments and ice sheet are considered as rigid body objects in order to compute their dynamics. Simulation of the motion of a system of rigid bodies is based on the Newton-Euler equations.

Two external forces are applied to the ice fragments to simulate their interaction with water: a buoyancy force and a drag force. The buoyancy force is applied on the immersed part of the ice fragment. The volume of this part is calculated at each time step. To apply the drag force, the ice fragment is divided into several volumetric elements. CFD software computes water velocity around the structure and from that the drag force on the fragment is determined.

Friction between the ice fragments and sheet, between the ice and the structure, and in shallow water, between the ice and the seabed, has to be considered. To model what happens when an ice sheet advances towards a structure, the penetration depth of the structure into the ice sheet is increased up to a limit set by the failure of the ice sheet. For a conical structure, the most common cause of failure is bending on the ice sheet. The ice sheet is considered as a semi-infinite plate on an elastic foundation.

This model is useful for predicting the initiation of cracks formed in the ice, simply by comparing the stress levels in the ice sheet with the flexural strength of ice. However, this alone does not predict the number and the extent of the cracks or the ultimate failure of the ice sheet.

Using fracture mechanics concepts, where the energy input from the external load is balanced by the energy dissipated in deforming the ice and creating the cracks helps define the ultimate failure of an ice sheet. Observations show that ice begins to fail by forming cracks in the radial direction, starting from the contact point. These radial cracks are due to the tension at the bottom of the ice plate. Increasing the forces applied on the ice will increase the number of radial cracks and lengthen them until a circumferential crack is formed. In the simulator, five wedge-shaped beams resting on an elastic foundation are used to model the cracking.

Ice fragments make up an important part of ice loads and these can be taken into account using a semi-infinite plate model. This simulates ice sheet failure due to a pile up of ice fragments generated by contact with the structure falling onto the ice sheet. As the ice continues to break up, the program computes the bending moment of each ice fragment depending on its contact points with other ice fragments, the structure, the intact ice sheet, and if necessary, the seabed. When this bending moment exceeds the flexural strength criterion, the fragment is broken into two new ice fragments. As the fragments pile up, they are taken into account in the loads on the structure.

There have been experimental basin tests of ice loadings on a multifaceted conical structure similar to the designs proposed for Arctic use, and the new software has been validated against these tests. The validation shows that the model results are in agreement with the basin tests.

An advantage of the simulator is allowing users to test a wide range of parameters in a short time frame when compared to basin tests. Ice sheet velocity and thickness, structural orientation, frictional coefficients and ice elevation can all be varied to help optimize the design geometry, or to validate the structural calculations for the design.

In conclusion, the IceSTAR software accurately models ice loads when the structure is moving, this new software simulator will do the same for a fixed or anchored structure where the ice is moving. OE

__Philippe Cambos__ is the technical director in charge of oil and gas projects, and Arctic projects for Bureau Veritas Marine & Offshore Division. He is a naval architect and helped develop the VeriSTAR software before going on to handle plan approval and design review for oil tankers, gas carriers and offshore units.

Permanent seismic reservoir monitoring on Jubarte

Claudio Paschoa provides insights from technical sessions at this year's Rio Oil & Gas event in Rio de Janeiro, Brazil.

At Rio Oil & Gas, Paulo Johann Ph.D., Geophysics Manager at Petrobras, explained how Petrobras is applying permanent reservoir monitoring (PRM), through high-quality 4D4C seismic reservoir surveillance, at record depths of as much as 1350m (4428ft) at the Jubarte field in the BC-60 block of the Campos basin.

Petrobras Geophysics Manager Paulo Johann. Photo from IBP.

The Jubarte field has a total area of 245sq km, and is located in the northern portion of the Campos basin, off the southern coast of Espírito Santo state. It sits 77km offshore in water depths ranging from 1185m-1365m. Jubarte's oil reserves are estimated at 600MMbbl of heavy (17.1°API) oil.

Although Jubarte lies in a pre-salt area, the reservoir is post-salt. Johann says that Petrobras had taken as many as 3.8 million sensor traces per square kilometer with four-component sensors at every 50m (164ft) along the cables. "There is very high potential for enhanced oil recovery, simply by increasing our knowledge about reservoirs. If we understand them, we can learn to exploit them better," Johann told the conference. Petrobras' subsea seismic grid is the first and only PRM project in deep waters, and Petrobras' primary objective is to validate the deepwater fiber optic sensing technology for detecting small impedance changes.

The target is to monitor oil and water flows inside the reservoir and pressure changes due to injection and production. Possible discontinuities, which would impact the flow and that couldn't be identified using regular 3D seismic data, will be revealed by 4D seismic data as an anomaly limit for difference volumes. This pilot project, launched at the end of 2012, is composed of 35.6km of seismic cables, arranged in two subsea arrays that cover 9sq km in the south portion of the Jubarte field. The seismic area covers 121sq km.

The cables are anchored 300m apart to ensure good coupling, reduce noise and prevent lateral movements due to currents. They have a total of 712 4C receiver stations (three-component accelerometers and a hydrophone) at 50m intervals and were deployed in parallel lines. Jubarte PRM acquisition geometry presents a super density of seismic traces. The area of interpretable seismic data for the main reservoir is approximately 35sq km. The first acquisition was concluded in February 2013 and the processing is ongoing by Petroleum Geo-Services (PGS). Passive monitoring of seismic activity of the reservoir is also being acquired for a four-month period before the second acquisition (first monitor) scheduled for December 2014.

The Jubarte PRM seismic system uses PGS's Optoseis technology. The system comprises a fully 4C (four-component) fiber-optic sensor array installed on the seabed and an optoelectronics controlling and recording unit installed on the FPSO *P-57*. Online data quality control is carried out aboard the FPSO, the seismic data is then uploaded to PGS's processing center in Rio de Janeiro for further processing by a team of PGS and Petrobras geophysicists. Following the installation of the system in deep waters, Petrobras and PGS began acquiring active seismic data at least once a year using a seismic source vessel and passive or microseismic data between them. The PGS OptoSeis system is totally optics and is based on the Michelson interferometer sensing elements. In addition to fiber optic seismic array, the system also contains led-in cables, wet-mate connectors and optoelectronics equipment.

Permanently laid sensor cables are an alternative to other forms of repeated, or 4D, seismic data acquisition. The processed seismic data and images, allow geophysicists, geologists and reservoir engineers to produce seismic interpretations that help Petrobras optimize reservoirs management of the Jubarte field.

"The great advantage of the permanent seismic monitoring project is to enable the optimal management of Jubarte's reservoirs, with huge potential impact on increasing the oil recovery factor," Johann says. The PRM will enable a

Paulo Johann Petrobras Geophysics Manager speaking about the PRM. Photo from IBP.

constant update of the geomechanical model of the Jubarte field and deepen the understanding of the value of microseismic data in deepwater projects. Data processing is in progress, and images to date have been high quality, achieving reservoir group requirements.

"4D seismic is attained through PRM by repeating 3D seismic on a regular basis, so we can create a dynamic model or film of the reservoir by adding different images above each other," Johann explained.

Currently, Petrobras is evaluating the possibility of extension of the permanent seismic array to the north and northwest Jubarte. OE

Nanotechnology applied to E&P

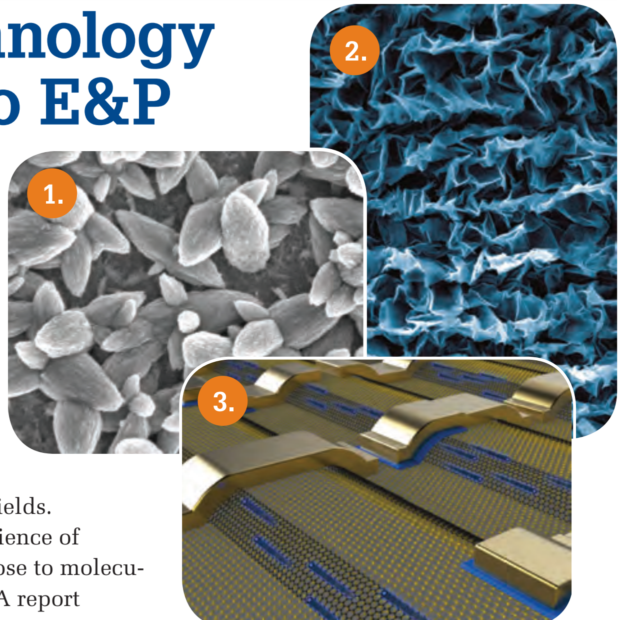
By Claudio Paschoa

Rio Oil & Gas also highlighted the growth in development of nanotechnology within the oil industry. The debate concluded that nanotechnology could definitely be an important tool to increase the efficiency of oil recovery in any field and specifically in mature fields.

Nanotechnology is the science of materials in a range very close to molecular dimensions (1-100nm). A report commissioned by the Lloyd's Register Foundation in 2013 said that nanotechnology will have a far reaching impact on almost every industry including energy, transportation, manufacturing, medical, computing and telecommunications.

The oil industry recently began investing heavily into different uses of nanotechnology as it provides prospects of advancement and major development in the various areas in the industry. Nanotechnology promises to bring advances in features such as coating against corrosion, embedded as nanosensors in structural materials such as concrete or inside engines, providing feedback on corrosion or stresses and producing continuous real-time data of structural and systems performance.

According to Baker Hughes' Vice President of Technology Ruston Moody, 60% of the existing nanotechnology patents are from the US and Canada and the number of patents has greatly increased in the last 10 years. Moody valued the market at US$9 billion, up from the $4.5 billion five years ago. Baker Hughes is currently developing a coating composed of carbon, which is manufactured through the use of nanotechnology. The innovative product can handle temperatures up to 700°F (371°C), which allows its use in geothermal wells.



1. Nanoscale coating of zinc oxide on top of a copper plate boost heat transfer coefficient 10-times according to experts at Oregon State University and the Pacific Northwest National Laboratory. Photo from Oregon State University. **2. Graphene crumples when compressed (shown here), but straightens back out when applying a voltage to the electro-active polymer to which it is attached, enabling a new electro-mechanical-optical material suitable for energy harvesting, optical switching and artificial muscles for robots.** Image from Duke University. **3. Electrons (blue in this artist's impression) travel nearly unimpeded along ribbons of graphene (black) that have been grown on steps etched in silicon carbide (yellow atoms).** Image from John Hankinson-Georgia Tech.

"Nanotechnology enables us seeing everything that one day we could only model. One of our challenges is figuring out how nanotechnology will really affect recovery of oil and gas," says Claudius Ferger, senior manager of smart devices at IBM Reserach Brazil. Petrobras has requested specifications from Industrial Nanotech, a company which specializes in nanotechnology, for applications of its thermally insulating and corrosion resistant coating, Nansulate. The specification is for a pipeline project, which consists of 105mi (169km) of 18in. pipe to be manufactured in Brazil.

Intensive research is ongoing within the oil industry to enhance oil recovery. Colombia's Ecopetrol is also using a method of inorganic nanoparticles injection in its Castilla exploratory process.

Richard Romero, petroleum engineer for Ecopetrol, says that they have tested two types of nanoparticles and the one with best results presented 112mg of asphaltenes, resulting in a reduction in petroleum viscosity along with a reduction of 35% in BWS. During the testing procedure, Ecopetrol achieved a record production of 141boe/d and increased the oil's mobility through nanotechnology. Nanoscale technology research shows that established chemical and physical properties do not hold and the nanoparticles may exhibit extraordinary magnetism or other changes in their micro and macro properties. A key development in nanoscale technology specifically for the oil and gas industry was the formation of the Advanced Energy Consortium, says Mohsen Ahmadian, Ph.D., Project Manager at University of Texas Austin. The AEC funds research projects of particular value to the industry at universities, labs and companies around the world. In many instances projects can involve partnerships between academia and industry.

Most operators are exploring various uses for nanotechnology. Shell, for example, employs nanotechnology to catalyze chemical reactions and also in preventing the pipe corrosion. Shell has millions of channel sensors designed to monitor how well their infrastructure is doing. With nanotechnology, the sensors can be made smaller and cheaper. The sensors would also be faster to produce, which could be vital when deploying millions of sensors at the same time.

The Brazilian Nanotechnology National Laboratory (LNNano), created in 2011, has been working on a range of projects in partnership with Petrobras. Research, such as study of duplex and super-duplex stainless steel welding ability, is ongoing.

LNNano is also the headquarters of the Bi-national Brazil-China Center of Nanotechnology, a project of bilateral cooperation between the Brazilian Ministry of Science, Technology and Innovation and the Chinese Sciences Academy, which facilitates cooperation in nanotechnology and nanosciences. OE

FURTHER **READING**

For more coverage from Rio Oil & Gas, please visit OEdigital.com

Solutions

3M expands rescue devices line

3M has expanded its personal safety portfolio to include two new rescue devices: 3M and DEUS' Escape and Rescue System, and the Latchways Personal Rescue Device (PRD) with 3M Elevation Harness.

The 3M and DEUS Escape and Rescue Systems enables workers to steadily control their descent from heights up to 590ft and allows for individual and multi-person escape, assisted rescue, and self-rescue after a fall. The system is available with two controlled descent options: the 3300 device has a decent rate of 3m/s from 350ft max; the 3700 device has a decent rate of 2m/s from 590ft max.

The Latchways Personal Rescue Device can help give users an unassisted, self-rescue from heights up to 65ft. It comes contained in a lightweight "backpack" and is activated by pulling a parachute-type cord where the PRD can then extend up to 65ft. In the event of a fall, the 3M Elavation harness suspends the wearer, while the Latchways PRD allows for a steady descent to the ground. www.3m.com

Atlas Copco's ER re-design

Atlas Copco re-designed the stand-alone, retrofit energy recovery (ER) units for its GA compressors, which offer improved performance and a smaller footprint.

The new ER units recover up to 94% of the thermal energy lost during the compression process to heat water up to 90°C for a number of process and domestic applications.

The ER heat exchangers are now vertically configured and are offered with the option of complete, corrosion-free stainless steel construction, for applications where water purity is critical.

All ER units are provided with sensors for ER water inlet and outlet temperature levels. The SMARTLINK remote monitoring system allows users to continuously monitor and analyse compressor conditions via an online portal. **www.atlascopco.com**

GexCon releases FLACS-Fire

GexCon released a software package specifically made for the oil and gas, processing, and industrial segments, FLACS-Fire, which generates detailed models of jet and pool fires.

FLACS-Fire shares the same simple interface and advanced modeling characteristics with FLACS. This translates to an easy learning curve for users, increased workflow efficiencies, and fast, accurate results.

The Windows and Linux-supported package models a wide range of scenarios, including, but not limited to, jet fires in cross winds, flash fires, over ventilated compartment fires, and large-scale field experiments. Typical application areas include escape route impairment (modeling heat, smoke, and visibility), vessel heat-up modeling, offshore and onshore installations, and factory building fires. **www.gexcon.com**

Rolls-Royce dynamic positioning simulators

C-MAR Group has installed and commissioned Rolls-Royce's Icon dynamic positioning simulators at its DP Training Centers in London and Mumbai.

C-MAR provides DP training with different manufacturer equipment in all its regional training centers. C-MAR uses multiple simulators to develop and strengthen students' knowledge and skills by demonstraating practical operation of how DP controls work to deliver the vessel's task, from dive support and anchor handling to platform supply and drilling operations. Students also learn how different manufacturers approach the challenges posed by dynamic positioning operations. **www.c-mar.com**

Kongsberg's new acoustic positioning system

Kongsberg Maritime introduced µPAP (microPAP), a new compact and portable acoustic positioning system for operation from a surface vessel to track ROVs, tow fish, divers and any other subsea target at depths to 4000m.

µPAP measures the distance and direction to subsea transponders and computes a 3D position in local coordinates or in geographical coordinates.

It is established that more elements provide better acoustic and mathematical redundancy and improvement of the Signal to Noise level. µPAP introduces a series of new transducers that feature more elements which can provide more accurate and reliable position data down to 4000m range. Also, a built in motion sensor in the µPAP transducer compensates for vessel roll and pitch movements, while using the Cymbal acoustic protocol provides wideband spread spectrum acoustic positioning and data communication.

To meet various demands from the market, the µPAP transducer is available in several versions featuring different built-in motion sensors and physical size. The size and weight allows µPAP to be a flexible solution for a diverse range of applications. **www.km.kongsberg.com**

Activity

Saudi Aramco opens Houston research center

Saudi Aramco opened its new Aramco Research Center in Houston. The facility will address challenges relating to production, drilling, reservoir engineering, geology, geophysics technologies, and advances related to subsurface sensing and control.

Saudi Aramco President & CEO Khalid A. Al-Falih, center, inaugurates the Aramco Research Center in Houston.
Photo from Saudi Aramco

Houston is one of many new centers for Saudi Aramco. In December 2013, the company launched its Cambridge, Massachusetts facility. CEO Khalid A. Al-Falih pledged to devote more resources to R&D. Another center, planned for Detroit, will focus on engine-fuel systems and development.

"Because of our belief that innovation and cutting-edge technology are the key strategic enablers to addressing the industry's challenges and to meeting future energy demand, we are tripling our R&D manpower and increasing our global R&D funding five-fold," Al-Falih says.

Methane hydrate consortium launched

Eleven Japanese companies, including oil and gas firm Inpex, have joined forces to create a new firm focused on methane hydrate extraction. Japan Methane Hydrate Operating Co., (JMH) was formally established 1 October specifically for the medium to long-term offshore production testing from pore-filling type methane hydrate.

JMH will work to develop technologies to enable methane hydrate extraction and production commercialization.

The partners in JMH are: JAPEX (33%), Japan Drilling (18%), INPEX (13%), Idemitsu Oil & Gas Co. (5%), JX Nippon Oil & Gas Exploration Corporation (5%), Nippon Steel & Sumikin Engineering Co. (5%), Chiyoda Corp. (5%), Toyo Engineering Corp. (5%), JGC Corp. (5%), Mitsui Oil Exploration Co., Ltd. (5%), Mitsubishi Gas Chemical Company, Inc. (1%).

Murphy Oil sells Malaysian assets

Murphy Oil Corp. agreed to sell 30% of its Malaysian oil and gas assets to PT Pertamina in a US$2 billion all-cash deal. Murphy will remain operator and continue with development plans.

Murphy holds majority interests in seven production sharing contracts in Malaysia. Murphy reports that its Malaysian fields contributed approximately 86,000 boe/d net production in 2013, more than 40% of the company's total.

Enegas joins TAP

Enagás has joined the Trans Adriatic Pipeline (TAP) project as a new shareholder with a 16% stake in Trans Adriatic Pipeline AG. The company also announced that existing shareholder Fluxys increased its stake in TAP from 16% to 19%. The new arrangement follows the purchase by Enagás and Fluxys of the 19% of TAP shares previously owned by E.ON (9%) and Total (10%). TAP's shareholding is now comprised of BP (20%), SOCAR (20%), Statoil (20%), Fluxys (19%), Enagás (16%) and Axpo (5%).

Andy Lane, chairman of the board of directors for TAP AG, said in a statement that the project's next stage included the construction of roads and bridges in Albania, which will begin in early 2015.

Spotlight

By Eugene Gerden

Gazprom Neft's Dyukov reflects on sanctions, technology, and future projects

Gazprom Neft, the fourth largest oil producer in Russia and subsidiary of Gazprom, may consider suspending the implementation of several projects on the Russian shelf due to Western-imposed sanctions.

Alexander Dyukov, was named Gazprom Neft's chief executive officer and chairman of its management board in 2008 after being named president in November 2006. He is also president of the Russian Premier League team Zenit St. Petersburg.

Dyukov gave a company update to Eugene Gerden.

To date, 3-4 companies have suspended cooperation with us on offshore projects. However, Gazprom Neft does not see any tragedy in their decision to do this.

How have Western sanctions affected Gazprom Neft's offshore projects?

Dyukov: They have had a negative effect on us, as several Western companies have already refused to work with Gazprom Neft on the shelf. To date, three to four companies have suspended cooperation with us on offshore projects. However, Gazprom Neft does not see any tragedy in their decision to do this. We are planning to find new contractors, possibly in Asian countries. At the same time, Gazprom Neft continues implementation of a practice of permanent import substitution, so the sanctions will not affect the company's operating and financial results. The sanctions may only cause inconvenience, associated with the need to coordinate deliveries of certain production and, in particular, equipment from abroad, in accordance with already-signed contracts.

Are there any possibilities that sanctions may restrict Gazprom Neft's access to loans from Western banks?

Dyukov: At present, the company's loan portfolio is comprised of two-thirds from the borrowings of American and European banks. In this regard, due to sanctions, we will have to borrow more in the Russian market in the future.

Does the company have all the necessary technologies for operations on the shelf? What will it take in order to obtain such technology?

Dyukov: Currently, Gazprom Neft has the majority of technologies for operations on the shelf. Earlier this year, the company signed an agreement with the Krylov State Research Centre, one of the world's major ship research and design centers, on the joint design of technologies and marine equipment for the development of offshore oil fields, which are currently operated by Gazprom Neft.

At present, the company operates several offshore fields, including the Prirazlomnoye field, an Arctic offshore oilfield in the Pechora Sea south of Novaya Zemlya. Its development is the first commercial offshore oil development in the Arctic. Its reserves are estimated at 610MMbbl. At the same time, the company has already started geological studies of the Dolginskoye (Pechora Sea) and the North Wrangel oil fields (East Siberian and Chukchi seas). All of these projects are implemented in difficult climatic conditions and are associated with the need to meet strict industrial and environmental safety standards.

Are there any plans to participate in any offshore projects overseas?

Dyukov: Yes, Gazprom Neft plans to take part in the auction for the development of several offshore oil and gas fields in Croatia. However, the names of these fields are not currently disclosed. So far, the government of Croatia has put up for auction 29 oil and gas blocks in the Adriatic Sea to conduct further exploration and development. Receipt of applications will last until 3 November 2014, and the results will be announced at the beginning of 2015.

Gazprom Neft believes that sanctions may be lifted by the end of the current year, due to the improvement of the current situation in Ukraine. OE

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.

November's Faces of the Industry takes us to the North Sea market with Alasdair Buchanan, COO of LR Senergy. With a career spanning more than 30 years, including leadership roles at BJ Services and Halliburton, Alasdair has earned an impressive track record in international operations, leadership, developing corporate strategy and growing organizations globally.

Childhood aspirations proved a catalyst for his colorful career, which has fueled his passion for travel by taking him to almost every corner of the world.

OilOnline recently had the opportunity to hear Alasdair's perspectives on his career, advice for others working in the industry, the outcome on the vote for Scottish Independence and other key issues facing the North Sea.

What did you aspire to do?

As a schoolboy in Thurso, in northern Scotland, I knew very early on that I wanted to get into the industry. There were lots of people leaving the area to move into the energy sector as it was very exciting. The opportunity to travel and experience new cultures was also a draw. When I left Thurso High School, I was certain I was going to be a chemical engineer. I got a job at the nearby Dounreay nuclear power site where I worked for a year before going on to study for a Bachelor of Science (BSc) in the subject at Edinburgh University.

How did your career begin?

I went straight into a job via BJ Services' graduate training program after leaving university in 1982 and spent the next 28 years of my career with the company, latterly as vice president of international operations based in the US. I initially worked offshore in the North Sea, where I actually met James McCallum, LR Senergy's chief executive officer, for the first time. He was working on the Britoil graduate program while I was doing my training.

I went on to work on onshore and offshore projects around the world as region operations manager for Europe and Africa, and then as regional manager for a number of other regions including Asia Pacific, Europe and Africa.

On leaving BJ Services in 2010, I worked at Halliburton as senior director for global strategy and then as UK vice president before being approached by James to join LR Senergy as COO. It was the first time we had worked together since the early 80s. It's come around full circle!

Was there a key turning point in your life that changed your course in a different direction?

Joining LR Senergy was a turning point, as it offered a very different working environment than I had previously experienced in large publically traded NYSE (New York Stock Exchange) listed companies. It was refreshing to be in a private company and to have the freedom to make decisions fast and responsibly without the 'red-tape' bureaucracy that can slow decision making.

What advice do you give to those looking to pursue an oil & gas career?

Oil & gas is an excellent industry to work in. There have been significant developments in technology over the past 20 years and new techniques that make it very exciting. Flexibility is a key attribute. You need to be able to travel, because experiencing different environments in different parts of the world is very valuable. Gaining hands-on field experience is also key – you can't manage operations from behind a PC. I'd also say be prepared to follow safety regulations to the letter.

What's your top life lesson you live by or top career life lesson you want to share?

Leadership by example. I don't think you can run a company and dictate to others how they should behave, without exhibiting the values and behaviors you expect those who work for you to display.

We understand that LR Senergy just completed a poll on key issues in the North Sea. Can you give us

Alasdair Buchanan

is chief operating officer at LR Senergy and managing director of the group's energy services business. He is responsible for day-to-day operations and executing business strategy at LR Senergy, which specializes in providing fully integrated project and asset development services across the international energy industry and has experienced rapid expansion across Africa, Europe and Asia Pacific as well as a growing foothold in the US.

A long-standing member of the Society of Petroleum Engineers, Alasdair has been a committee member of Unconventional Gas Aberdeen since its outset and is playing an instrumental role in LR Senergy's drive with LR Energy – part of the LR Group – to shape industry guidelines and regulations for the development of shale resources.

a sneak preview of your top 2-3 findings?

After becoming a part of Lloyd's Register (LR) Group last year, we conducted an industry poll with its engineering, technical, and business services organization, LR Energy, to find out what people thought was the main one out of five crucial issues affecting the North Sea's future. The key issues identified are the knowledge shortage, decommissioning, supply chain, operating costs and technology. As part of our "Collaboration is Key" campaign, the findings showed that almost half of all respondents (44%) consider operating costs to be the primary issue followed by technology (19%), decommissioning (14%), supply chain (14%) and knowledge shortage (9%).

We hope the campaign will be a catalyst for ongoing industry engagement which produces constructive and tangible results.

Are we making too much out of the skills shortage ?

The industry is right to be concerned about the skills shortage because the situation has heightened due to a number of factors from the aging workforce and evolution of the industry, which means that one of the key challenges is having the right people with the right technical skills.

But, while there are an extensive number of industry initiatives to help address the issues, it's important that companies also play their part. LR Senergy is involved with a number of partnerships with universities and educational institutes. For example, we joined forces with the University of Aberdeen to launch a pioneering collaboration in direct response to the growing demand for petrophysicists.

What is your reaction to the Scottish referendum?

One of the key issues for LR Senergy wherever we're operating in the world is operational costs and robust regulatory regimes. Therefore, what we hope for following the referendum is that the current levels of government commitment to the energy industry continue and, if anything, increase.

The North Sea energy industry has created a great environment and opportunities for entrepreneurs to develop technically innovative products and services. As the energy sector in the North Sea has matured, increasingly creative solutions have been required to overcome technical challenges, but more needs to be done to encourage further investment and to help ensure reserves are fully exploited through a fit-for-purpose fiscal regime.

How would you like to be remembered? What would your former colleagues and employees say about you?

Well, if you asked my children how to describe me, they'd probably say 'he's quite intense and quite sensible' so chances are my colleagues would say the same! But, on top of this, I like to think that I'm very approachable and supportive of my colleagues, and with the utmost integrity. I like interacting with my team and passing on the wisdom I have gained from my experiences and mentors. I suppose I'd like to be remembered for making a difference and improving the structure of businesses that I've been involved with and, as part of this, helping to support and develop talent of the future.

His children and colleagues would most likely agree with his conclusions. Alasdair is a leader who understands that success goes beyond just him. He is passionate and intense about helping his organization thrive by investing in people and ground-breaking technologies to continue the momentum into its next exciting chapter. **OE**

Faces of the Industry features 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.*

Editorial Index

Advertiser Index

OE Advertising sales

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

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

UNITED KINGDOM
Mike Cramp, Alad Ltd
Phone: +44 0 7711022593
Fax: +44 01732 455837
mike@aladltd.co.uk

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

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

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

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

CHINA, HONG KONG & TAIWAN
Henry Xiao
Phone: +86 21 3921 8471
henry.xiao@matchexpo.com

SINGAPORE, MALAYSIA, INDONESIA, THAILAND & KOREA
Anthony Chan
Phone: +65 63457368
acesap@gmail.com

RECRUITMENT ADVERTISING
Liane LaCour
Phone: +1 713-874-2206
llacour@atcomedia.com

DIRECTORY ADVERTISING
Rhonda Warren
Phone: +1 713-285-2200
rwarren@atcomedia.com

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Numerology

20% The percentage of global undiscovered hydrocarbons that the US Geological Survey estimated to reside in the Arctic. See page 25.

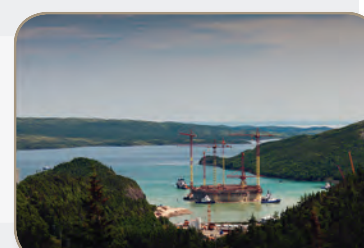
US$6.5 billion The price of the Leviathan field off Israel's estimated initial development plan. See page 20.

600MMbbl

of heavy oil are estimated to be held at the Jubarte field in the Campos basin off Brazil's Espirito Santo state. See page 70.

25years The intended service life of most FPSOs and FPSs See page 28.

150,000b/d The production capacity of ExxonMobil's Hebron project off Newfoundland and Labrador. See page 64.



1350m Petrobras is applying permanent reservoir monitoring at record depths of as much as 1350m at the Jubarte field. Located off Brazil in the Campos basin. See page 70.

US$150million The contract amount awarded by Saipem to Ocean Installer for SURF work off Brazil. See page 23.

41%

The predicated rate of increase in global energy consumption during the period of 2012 – 2035, as 20% found by BP. See page 54.

24ft represents the amount of recorded single line failures within MODUs. See page 58.