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# FLOATING PRODUCTION

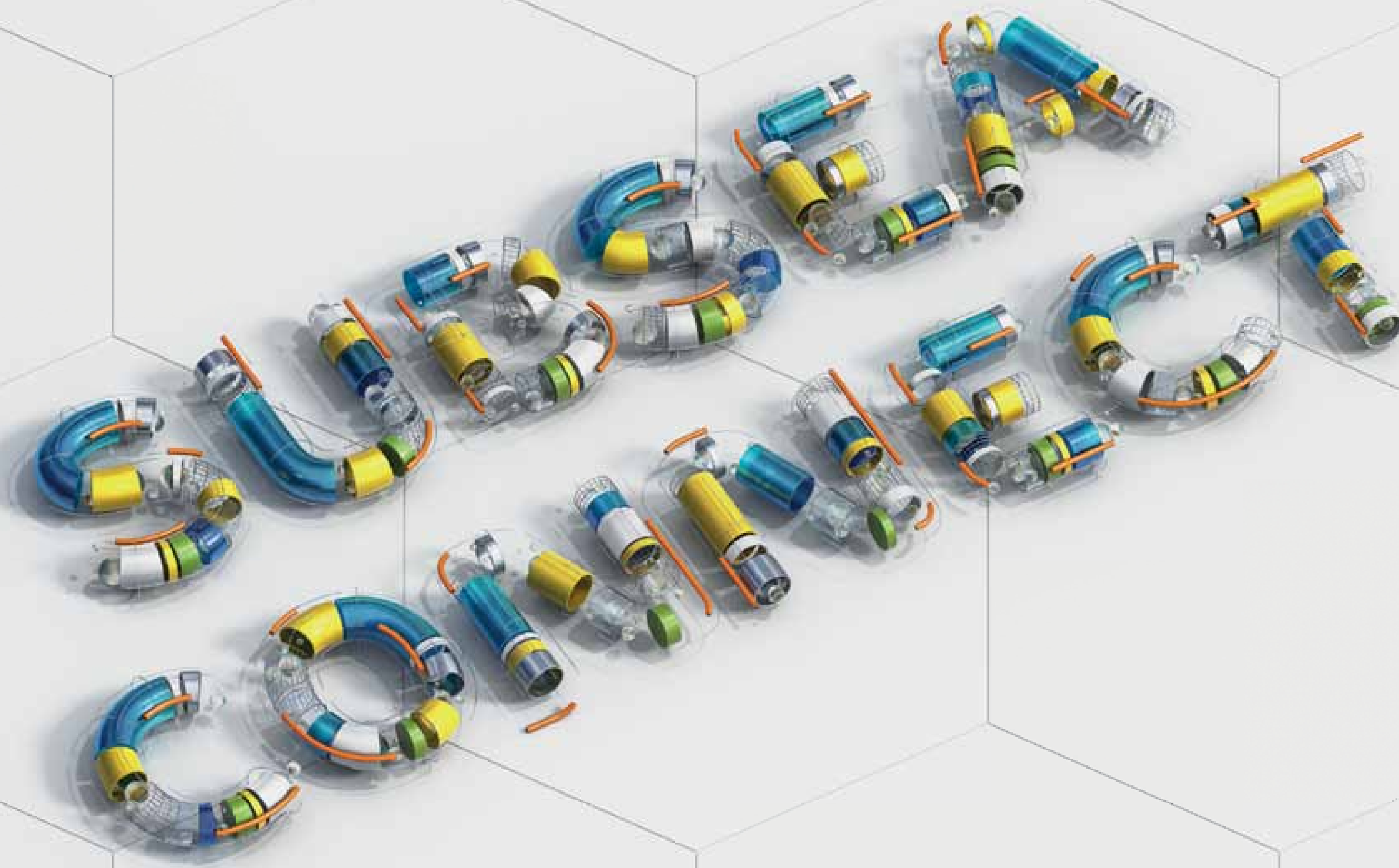
## THE MARKET HEATS UP

**Subsea Visualization**
Clearing the View

**IRM @ Mad Dog**
From Drones to Mag Crawlers
New Tech Cuts Costs

**Plugging & Abandonment**
New Solutions Abound

VOL. 44 / NO. 1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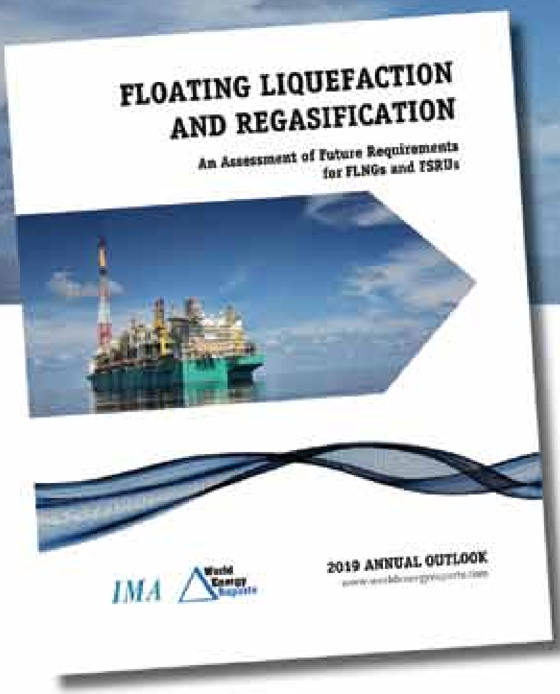
# REAL TIME ANALYTICS & REPORTS FOR THE FLNG/FSRU MARKETS

"The LNG industry is going through a dramatic transformation. Our 2019 Annual Outlook and real-time FLNG/FSRU database is unique. It is not simply a static report, rather a dynamic and ever-changing database with a continuously updated wealth of data, statistics, exclusive insights and analysis and critical project management contacts designed to keep you a step ahead of the competition.




## THE 2019 ANNUAL OUTLOOK

**76** — **FLNG Projects Tracked**
There are numerous FLNG and FSRU projects in the planning stage. Not all will move to development. To sort the likely from the unlikely we developed a methodology to rate projects based on specific "success drivers".

**130+** — **Exhibits & Infographics**
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There are numerous FLNG and FSRU projects in the planning stage. Not all will move to development. To sort the likely from the unlikely we developed a methodology to rate projects based on specific "success drivers".

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# FEATURES

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**ON THE COVER: Prelude FLNG** on-station 475 kilometers north, north-east of Broome, Australia. (Source: Shell)

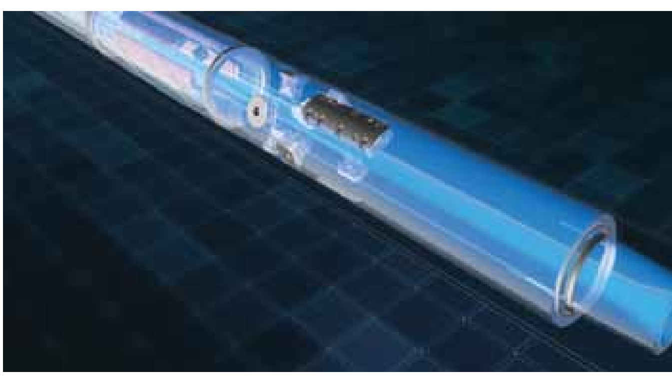
# F E A T U R E S

Source: Comex Innovation



Source: BP





Source: BHGE



Source: Altus Intervention

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# DEPARTMENTS



Source: Blue Ocean Monitoring

Source: AOG

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Source: Teledyne Energy Systems Inc.

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Source: Baker Hughes, GE

# BY THE NUMBERS

# RIGS

**Worldwide**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 35 | 56 | 91 | 62% |
| Jackup | 144 | 308 | 452 | 68% |
| Semisub | 42 | 59 | 101 | 58% |

**Africa**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 2 | 14 | 16 | 88% |
| Jackup | 8 | 25 | 33 | 76% |
| Semisub | 1 | 4 | 5 | 80% |

**Asia**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 7 | 7 | 14 | 50% |
| Jackup | 52 | 90 | 142 | 63% |
| Semisub | 12 | 15 | 27 | 56% |

**Europe**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 16 | 3 | 19 | 16% |
| Jackup | 13 | 36 | 49 | 73% |
| Semisub | 14 | 20 | 34 | 59% |

**Latin America & the Caribbean**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 6 | 13 | 19 | 68% |
| Jackup | 4 | 5 | 9 | 56% |
| Semisub | 7 | 7 | 14 | 50% |

**Middle East**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Jackup | 32 | 118 | 150 | 79% |

**North America**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Drillship | 4 | 19 | 23 | 83% |
| Jackup | 30 | 27 | 57 | 47% |
| Semisub | 4 | 7 | 11 | 64% |

**Oceania**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Jackup | 1 | 1 | 2 | 50% |
| Semisub | 1 | 3 | 4 | 75% |

**Russia & Caspian**

| Rig Type | Available | Contracted | Total | Utilization |
|---|---|---|---|---|
| Jackup | 4 | 6 | 10 | 60% |
| Semisub | 3 | 3 | 6 | 50% |

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

Data as of January 3, 2019. Source: Wood Mackenzie Offshore Rig Tracker

## DISCOVERIES & RESERVES

**Offshore New Discoveries**

| Water Depth | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|
| Deepwater | 26 | 13 | 15 | 6 |
| Shallow water | 84 | 65 | 71 | 29 |
| Ultra-deepwater | 18 | 15 | 12 | 14 |

Shallow water (1-399m)
Deepwater (400-1,499m)
Ultra-deepwater (1,500m+)

**Offshore Undeveloped Recoverable Reserves**

| Water Depth | Number of fields | Recoverable reserves liquids mbl | Recoverable reserves gas mboe |
|---|---|---|---|
| Deepwater | 564 | 23,247 | 67,217 |
| Shallow water | 3,200 | 105,702 | 300,381 |
| Ultra-deepwater | 330 | 34,498 | 50,755 |

Contingent, good technical, probable development.

The total proven and probably (2P) reserves which are deemed recoverable from the reservoir.

**Offshore Onstream & Under Development Remaining Reserves**

| Water Depth | Number of fields | Recoverable reserves liquids mbl | Recoverable reserves gas mboe |
|---|---|---|---|
| Africa | 736 | 29,303 | 30,388 |
| Asia | 1,025 | 17,251 | 40,197 |
| Europe | 957 | 19,808 | 24,215 |
| Latin America & the Caribbean | 244 | 43,293 | 13,271 |
| Middle East | 142 | 138,841 | 108,783 |
| North America | 940 | 25,279 | 5,528 |
| Oceania | 123 | 2,752 | 24,980 |
| Russia and the Caspian | 70 | 26,535 | 23,205 |

Onstream and under development.

The portion of commercially recoverable 2P reserves yet to be recovered from the reservoir.

Source: Wood Mackenzie

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Trauthwein


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# WELCOME BACK!

It is with tremendous pride that I welcome you to the first edition of the new *Offshore Engineer (OE)*. Many of you already know the brand fairly well, as both the magazine and the online presence at **OE-Digital.com** has been a leading voice in the offshore energy sector for more than 40 years. In fact, after we acquired the assets of AtComedia in Q3 2018 and our plans to revive this title became public, I was struck by the avalanche of good will and positive comments from subscribers and advertisers alike, a true credit to the people who worked tirelessly to create and shape this revered brand since 1975.

We did not enter the task to relaunch *Offshore Engineer* lightly or blindly. The offshore energy industry is in the midst of a historic and prolonged downturn that is reshaping the business. As prices hover between $55 and $70 per barrel, 'the new norm' is focused on new technologies, automation and digitalization to drive down the price of offshore energy discovery and recovery. Our business, b2b publishers in print, online and via any means electronic, is in the midst of a historic transformation too. We were founded in 1939, a company celebrating our 80th anniversary in 2019, with titles including *Maritime Reporter & Engineering News* and **MarineLink.com**. For the past 20 plus years, with the advent of the IoT revolution and all that it entails, the 'media' space has become a crowded one as the barriers to entry have faded and anyone with an electronic device, a WiFi connection and something to say can instantly position themselves as a sector expert. But that is precisely why acquiring and reviving the *Offshore Engineer* was so attractive: we are long-tenured publishers in every market we serve, and *Offshore Engineer* provided a household name in the offshore energy sector, highly regarded with a rich history and promising future. The task of building that future started late last year when OEDigital.com came back to life after a 10-month hiatus, culminating with this, the first of six print editions of *Offshore Engineer* in 2019.

To the left you will see our *OE* writers, and I am pleased to say that two key members of the old *OE* editorial team have transitioned to the new *Offshore Engineer* team, **Elaine Maslin** and **Jennifer Pallanich**. Their contribution to this rebirth far transcends the supply of words and images, as both Elaine and Jennifer have been gracious with their time and knowledge, instrumental in providing background, perspective and insight on both the magazine and this dynamic, fast-changing industry.

While my face and words are here now, you will become much more familiar with my colleague **Eric Haun**, Managing Editor of *Offshore Engineer* and OEDigital.com. His is the face you will see at exhibitions, conferences and symposia around the world for years to come. Eric is a hard-working, tenacious and talented editor and writer, and I invite you to be in contact with him regarding all matters editorial.

The editorial team – the foundation of *Offshore Engineer's* past and future success – does not end here as we have assembled and continue to grow an impressive team of writers and contributors situated in key global locations, supplying exclusive insights both in print and weekly online, every business day, via the "Insights" section on OEDigital.com.

With that I'll leave you to peruse the January/February 2019 edition of *Offshore Engineer*; we encourage and welcome your feedback. While it has been a steep climb to get where we are today, watch this space and OEDigital.com for additional offerings throughout the year, because the real work has just begun.

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# IMAGING THE FUTURE

**BY ELAINE MASLIN**

Once upon a time, visual inspection of subsea infrastructure meant divers taking still cameras down to the seafloor, hoping that the camera casing wouldn't flood, or that the film wouldn't be over exposed or destroyed during development. Even using the first remotely operated vehicles (ROV) with a live video feed, it was difficult to catch a long enough sight of an inspection target, due to limited control and positioning functionality if there was any level of current.

It's safe to say, the industry has come a long way since and the imaging possibilities are expanding by the day. In fact, the problem is now starting to become how to process the "tsunami" of data that's being gathered. [See sidebar page 10]

These issues were top of the agenda at a joint seminar held by The Hydrographic Society in Scotland (THSiS), the International Marine Contractors Association (IMCA) and the Society of Underwater Technology (SUT) in Aberdeen in October.

On the one hand, sensor platforms are evolving. Both ROVs and autonomous underwater vehicles (AUV) are becoming faster to use; BP has a target to have 100% of subsea inspection performed via marine autonomous systems (MAS) by 2025, Peter Collinson, senior subsea and environmental specialist at BP at the oil major, told the seminar.

They're also becoming more autonomous, supported by onshore operations centers. Equinor has already trialed piloting ROV operations from onshore centers (via Oceaneering and IKM) and this year it's set to trial Eelume's snake-like subsea robot in a subsea garage at the Åsgard field offshore Norway, on a tether. By 2020, it hopes to go tetherless, Richard Mills, director of sales, Kongsberg Maritime Robotics, told the seminar. The next step could be use in combination with unmanned surface vessels.

Meanwhile, imaging technologies, from laser to photogrammetry, are helping these platforms to gather more data, faster and, potentially, also help them navigate.

**INSET Comex's ORUS3D system integrated onto an ROV for operations in the North Sea in 2018.**

**Subsea survey operations using an ORUS3D system.**

Source: Comex Innovation

**Pretty – measurable – pictures**

On the fly surveys are being done using photogrammetry. In summer 2018, Comex Innovation completed two North Sea offshore inspection projects using its ORUS3D underwater photogrammetry technology, having previously done projects in West Africa, Raymond Ruth, U.K. and North Sea Agent for Comex Innovation, said. Both operations, in the U.K. and Danish sectors of the North Sea, called for high accuracy measurement, one in support of brownfield modifications.

The ORUS3D subsea optical system measures and then creates high-resolution 3D models of subsea structures. Each system comprises an integrated beam of tri-focal sensors, with four wide beam LED flash units, plus a data acquisition and processing unit. It uses triangulation of features within the images captured to localize its relative position and build a 3D point cloud reconstruction that can be used for measurement, so that an inertial navigation system or target placement on the object for scaling are not needed when on site.

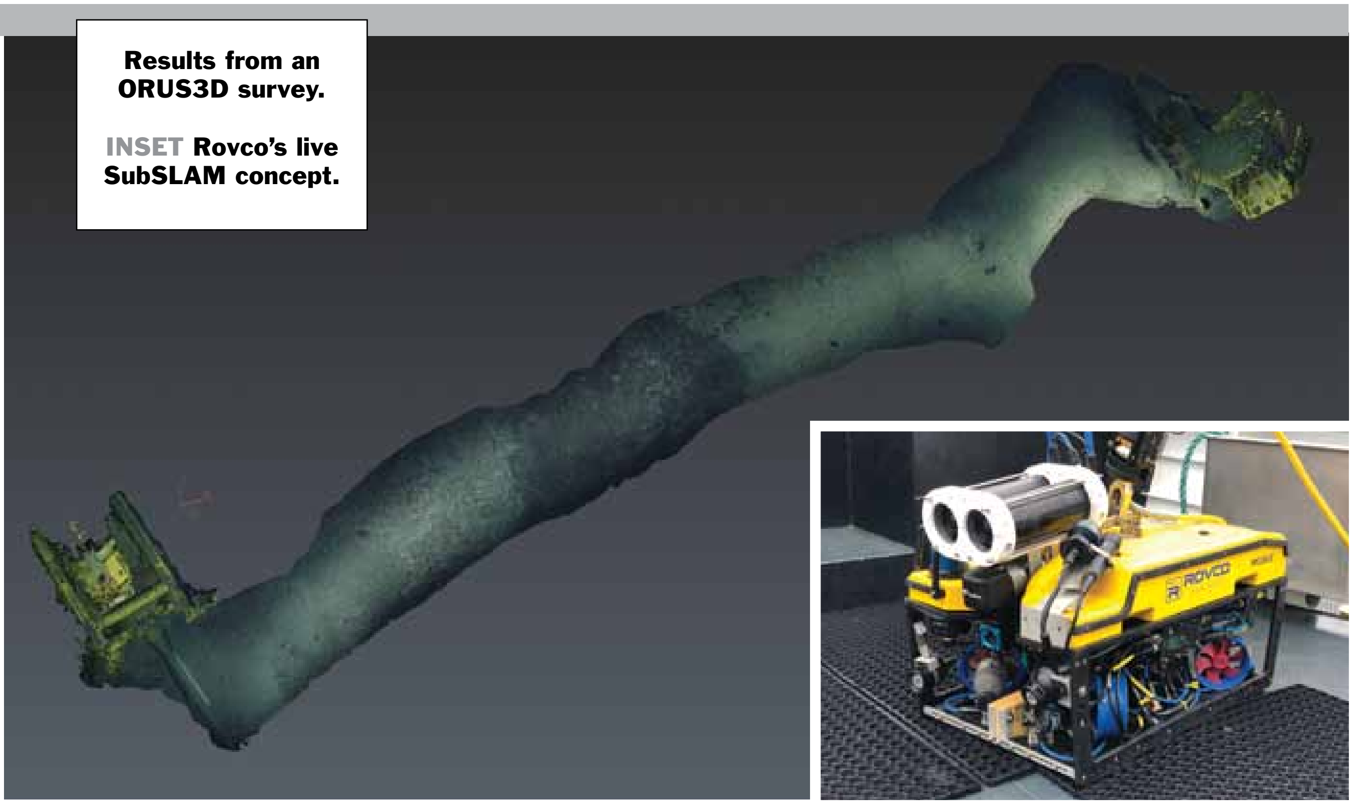
The integrated unit fits on to an ROV for free-flying data acquisition from more than 40cm away from structures, although the best distance is between 1-2m from the object. This takes no longer than a general video survey, Ruth said.

Initial onboard real-time processing is carried out to assess location and quality, before onsite (on the support vessel) processing, to further quality check the data and create an initial scaled 3D model to cm accuracy. Final processing of the data, which is collected as point cloud data, is then carried out to reconstruct the site or object in a 3D model to mm accuracy.

**Automated eventing**

EIVA has been working on the use of machine learning and computer vision techniques to detect objects such as anodes on pipe, pipe damage and marine growth automatically, using a conventional camera, said Matthew Brannan, senior surveyor, EIVA. To use machine learning means having to train a system with tens of thousands of images from pipelines. This is what EIVA has been doing, and it's bearing fruit. The company has run trials on existing data sets that were evented the traditional way, so it was possible to compare the automated results with the manmade eventing. Late 2018, it also started live testing during ROV-based operations. The ultimate aim for the technology is for automatic event recognition during an AUV survey, enabling an AUV to spot something and then send a message to a surface vessel, Brannan said.

EIVA is also taking conventional cameras further, using simultaneous location and mapping (SLAM) and photogrammetry to do map areas, while being able to locate the camera's position relative to what it is mapping. Existing SLAM systems rely on loop closure, and photogrammetry solutions need a lot of image overlap and good visibility, and are usually not real-time, Brannan explained. Some also rely on costly stereo cameras, which need calibration and take up space, he said.




**Results from an ORUS3D survey.**

**INSET Rovco's live SubSLAM concept.**

Source: Comex Innovation; INSET Source: Rovco

## DATA TSUNAMI

New imaging technologies are creating new opportunities for subsea visualization and autonomy. They're also creating a "data tsunami" challenge for operators. Peter Collinson, from BP, said, "One of the biggest concerns is (that) when you start to send fleets of AUVs out there, we will have a tsunami of data coming at us. We have been focused on [sensor/survey] platforms, because we are still building trust in what these systems are and what they can do. The data piece is coming ... dealing with that data in a timely fashion. How do we form a digital twin and get through to predictive, time series automated change detection?"

While data gathering evolves rapidly, future focus is on data delivery to the people who need it, such as pipeline engineers, in a format that is meaningful and useful. Artificial intelligence (AI) will help, said Malcolm Gauld, from Fugro, through using cloud computing and automatically detecting anomalies or defects. But it will take time to develop systems, he said. Fugro is working on this and has been performing trials in Perth, which have helped raise issues with the AI, such as differentiating a silvery pipeline coating from a shark. Future steps include building autonomy into that AI. But, Gauld suggested that new models should also be looked at. Could pipelines be built with sensors, making it 'smart' from the start with all maintenance predictive, he asked. "In the future it will not be about what equipment you use to get that data, but what you get out of that data."

In fact, in the future, we will not even be looking at this data, suggested Joe Tidball, senior surveyor at Rovco. Artificial intelligence, robotics, will do the interpretation and decision making. "I don't think that in 10 years we will be looking at video anymore. We will simply get reports emailed from robots in the North Sea saying you need to look at XYZ."

EIVA calls its system VSLAM, or visual SLAM. By creating a sparse point cloud on the fly, VSLAM can locate itself (i.e. the vehicle it is on) in its environment and use the model it's creating to automatically track and scan subsea structures. This is possible with a single camera, Brannan said, and from still images or images extracted from video, by tracking points in each image, and estimating a track, using those points, to build the sparse point cloud, creating a digital terrain model. An AUV would also know its original absolute position and could then use waypoints (i.e. landmarks) along the route.

The point cloud can then be used to create a dense 3D point cloud and then a mesh, with color and texture added. EIVA has had a team working on this since 2017 and is now testing the system on AUVs. This year, it will be running live projects, with visual navigation, Brannan said, and following that it wants to aid autonomous inspection and light intervention.

### subSLAM

Rovco has a vision to deploy an AUV with an autonomous surface vehicle (ASV) to perform surveys and mapping with its SubSLAM live 3D image and mapping technology. SubSLAM allows an ROV to build a 3D map of its environment on the fly, without using other inertial navigation or positioning systems. The firm calls it live 3D computer vision.

Rovco's SubSLAM X1 Smart Camera technology uses a dual camera system to create a live point cloud of what it sees. This is then used to calculate the vehicle's position relative to what it's looking at.

Rovco has been using SubSLAM on a Sub-Atlantic Mojave observation ROV, but is making it compatible with other platforms, said Joe Tidball. The firm plans to acquire its first AUV, a Sabertooth, from Saab Seaeye, this year, integrating SubSLAM in 2020, and then building artificial intelligence (AI) into the system in 2021. It's then looking to deliver surveys from an ASV from 2022.

Tidball said the system is suitable for subsea metrology and could be used with a tetherless vehicle using acoustic communications, linked to a surface communications gateway with radio/cellular or satellite networks and then to the cloud, where engineers could access a browser-based measurement tool – being fed with live 3D data. With AI, the vehicle could then make assessments itself.

Rovco tested its SubSLAM system at the Offshore Renewable Energy Catapult in Blyth, northeast England, in August 2018. Tidball said the company trialed the measurement accuracy it could achieve using terrestrial survey data on structures in a dry dock, which was then flooded so SubSLAM could do its work in 1.2m visibility. The underwater data was compared against a laser scan. Compared with the two hours taken to do an open-air survey, with 1.7mm alignment error, SubSLAM achieved 0.67mm error, from a two-minute scan, Tidball said.

Tidball said the system could negate the need for long baseline (LBL) systems, for positioning accuracy, but said visibility was a factor, for the cameras to work. While the technology is able to position the ROV or AUV within its environment, if it was moving to another site, and was tetherless, inertial navigation would be needed.

**Back to the future**

The techniques used to create point clouds on the fly can also be used to create point clouds from existing images or video footage, said Dr. Martin Sayer, managing director at Scotland-based Tritonia Scientific. As an example, Tritonia used its technology as part of a net environmental benefit analysis of a platform jacket in a tropical location, where an operator wanted to determine how much extra weight marine growth would add to a jacket, for lifting operation calculations and onshore disposal planning. Tritonia was given existing ROV footage to assess. This had been taken for fish life surveys, not jacket biofouling, so it was not designed or intended for 3D modeling. Two HD cameras and a standard camera had been mounted on the ROV, left, right and central.

Due to light in the water and most of the footage being directed at fish, about 95% of it wasn't useable. The rest was shot at night, making it more suitable, with no surface interference and better contrast, enabling a full near complete section of leg to be modeled. By removing the known leg volume from the model, the marine growth volume coulld be calculated.

**On the fly**

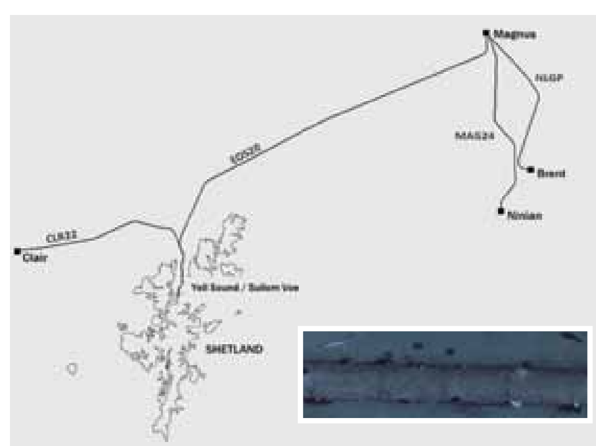
For some, the real potential of all of this technology is being able to process data live and using that information to feed back in live (albeit supervised) autonomous systems.

There's a feedback loop that will make these operations more powerful. "Processing the data [that we collect] automatically is when we get value," said Nazli Deniz Sevinc, uROV project lead, OneSubsea. "Plus, [it's] a feedback loop into supervised autonomy algorithms and feature detection," such as Brannan discussed.

A lot is happening. Supervised autonomy, autonomous fault detection, unmanned operations, without the need for support vessels, are the goal. There are hurdles, such as legislation, which in the area of unmanned vessel systems is behind the technology that's available. There are issues with data standards and how to handle the amount of data now being created, and not least adapting these techniques into today's workflows (or adapting the workflows themselves). It's a fast-moving space to watch with a huge amount of blurring boundaries (if not images).

# FAST PIPELINE INSPECTION

For pipeline surveys, BP has been focusing on doing things faster. In 2017, BP contracted DeepOcean, using a "Fast ROV" (pictured above, Superior ROV from Norway's Kyst Design) to survey 478km of pipeline (map below), between the Clair and Magnus facilities in the North Sea to Sullom Voe Terminal, onshore Shetland, and from the Brent and Ninian facilities to Magnus, all in just under four days. The survey included laser, HD stills cameras and Force Technology field gradient cathodic protection survey (CP) systems (FIGS), and averaged 5.1kt/hour inspection time, 6x faster than a standard ROV and 5x faster than a modified standard ROV, said Collinson. It also included side scan and multibeam survey data. The end result was a 3D scene layer file, a 2D georeferenced mosaic and event/anomaly listings.




Source: BP

# 'INSTALL-ABILITY' A STRUCTURAL SHIFT FOR THE SUBSEA SUPPLY CHAIN

**BY GREGORY BROWN,** Associate Director - Offshore, Maritime Strategies International Ltd.

Late cycle contractors may have changed the subsea sector for good and as lead times shorten, schedule optimization is an increasingly vital consideration for offshore project developments.

In prior generations, a subsea original equipment manufacturer's (OEM) duty of care would often end at the quayside. A typical scope of work might see the equipment provider engineer, procure, fabricate and deliver the hardware ready for an installation contractor to install it. Little thought was given to how the host of manifolds, templates, trees and so on would eventually find their way to the seabed, much less how that process could be optimized.

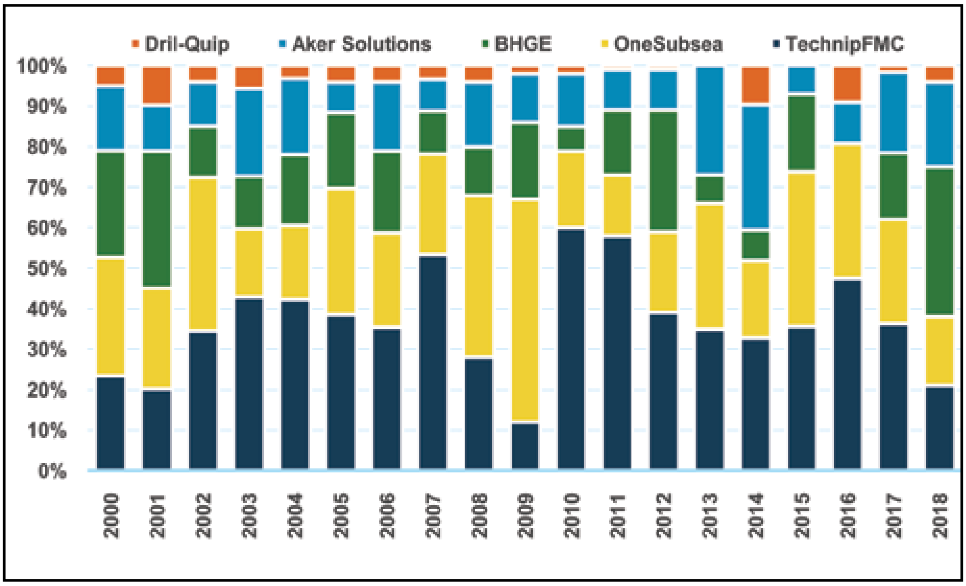
Time passed, and more demanding reservoirs in deeper and harsher environments gave rise to equipment built to ever stricter standards. Increasingly stringent health and safety requirements saw added redundancy and functionality built in, which in turn saw infrastructure grow in size and complexity.

Installing the hardware became even more challenging. Owners of single-lift vessels were able to charge hefty premiums for the ability to handle the hardware safely and install it. A host of field development vessels were delivered to service a market that showed little signs of cooling off. With premium charter rates for high-end tonnage an accepted market dynamic, and subsea manufacturers striving for double-digit operating margins, the subsea industry played host to rampant cost escalation.

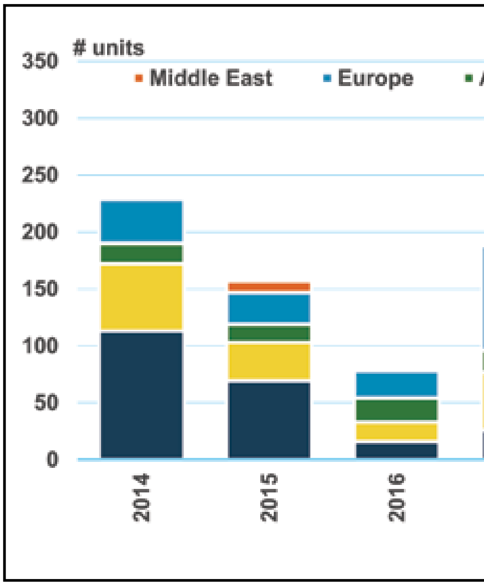
Then the downturn happened. Offshore reserves were immediately placed in competition with alternative investments including shorter payback onshore developments and the market collapsed. Subsea was uncompetitive.

Now the industry has reacted and a new generation of hardware has been launched. As well as having fewer parts and modules, the most recent systems have been designed with install-ability in mind. This structural shift has altered vessel requirements too. High end tonnage looks marginalized and uncompetitive in a market that is set to be served by smaller, fit-for-purpose vessels with lower overheads and less redun-

**SUBSEA OEM MARKET SHARE** Source (all charts): Maritime Strategies International




**SUBSEA TREE AWARD FORECAST**



dant technology on board. No longer are vessels required to lift well in excess of 3,000 metric tons in the subsea space. The industry is able to do more with less.

The shift toward install-ability is not just a function of economics. It reflects the impact of consolidation and collaboration within the supply chain. Going forward we see such collaborative efforts driving a greater prominence of bundled products and services with industrial players looking to deliver across multiple value chains.

It is perhaps no surprise that the leading proponent of this new generation – TechnipFMC – is the only player with a fully integrated supply chain, and a vessel fleet that does not include any assets capable of lifting more than 1,200 metric tons.

The legacy Technip lacked the capacity to install the largest infrastructure – from ultra-deepwater risers through to the largest manifolds. It had to serve the market via a partnership with Heerema that now looks to be increasingly redundant. Technip's influence as a later-cycle player helped the legacy FMC business to consider 'install-ability' when the Subsea 2.0 product suite was being developed.

Subsea 2.0, which includes a new generation of subsea trees, manifolds, control systems and pipelines, has been designed with fewer components and smaller footprint to enable it to be installed using smaller construction vessels.

The products have been optimized to best match what the business can provide under one contract, without the requirement to use external resources. The contractor has attempted to capture as much of the value chain as possible using its asset base – from engineering through to fabrication and eventually installation.

We see a similar shift from the competition: Baker Hughes GE's Subsea Connect portfolio has been designed to be installed using smaller construction ships, and Aker Solutions' latest generation subsea compression unit is half the size of the most recent installation at Asgard off Norway. That latest subsea compression design could be used imminently at Jansz-Io off Australia, and Ormen Lange off Norway.

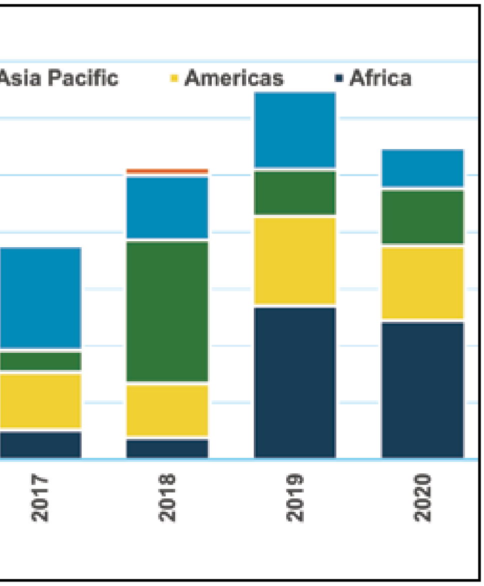
The shift toward install-ability is a structural change for the industry in our view. With a recovery in subsea activity in sight, albeit unlikely to gather momentum until around 2020, we see an opportunity for those contractors able to provide a service across the value chain. We also see a growing opportunity for vessel owners and operators to collaborate with OEMs, and for oil companies to be increasingly receptive to vendor-based solutions.

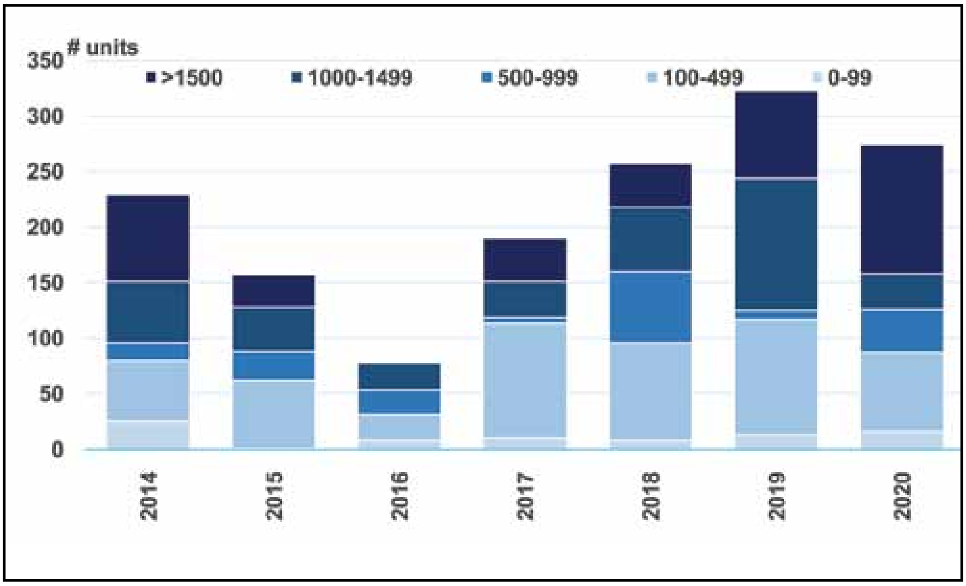
Install-ability is part of a broader theme of project optimization. The offshore industry is only now starting to see the benefit of these lower cost programs. The redesigned projects, competitive with alternative investments elsewhere, prop up a healthy queue of projects set to be sanctioned in 2019, particularly for the second half of the year.

That hopper of subsea work represents a material opportunity for the light construction fleet which is set to become increasingly competitive for offshore installation work over the next two-to-three years. With field infrastructure increasingly designed to fit within a smaller footprint, light construction vessels are increasingly able to deliver a full installation scope of work.

Unlike larger construction assets, which look set to be in a state of oversupply for the foreseeable future, lighter construction assets are one of the few subsectors of offshore set to tighten over the coming cycle.

**SUBSEA TREE AWARD FORECAST** by Water Depth



# FPSO SECTOR OUTLOOK FOR NEW ORDERS & GROWTH TRENDS

**BY JIM MCCAUL,** IMA/World Energy Reports

Floating production storage and offloading vessels (FPSO) are by far the most popular type of floating production system, accounting for two thirds of the oil and gas production floaters in service or available.

### Growth in FPSO inventory

The number of FPSOs in operation or available for deployment has grown by 33% over the past 10 years, from 151 units at end-2009 to 201 units at end-2018. This increase reflects the net result of delivery of new FPSOs and scrapping of aging units over the 10-year period.

There are currently five FPSOs on order for delivery in 2019. Assuming no scrapings of FPSOs over the next 12 months, the expected deliveries will bring the total inventory to 206 FPSOs at end-2019.

### 10-year trend in FPSO orders

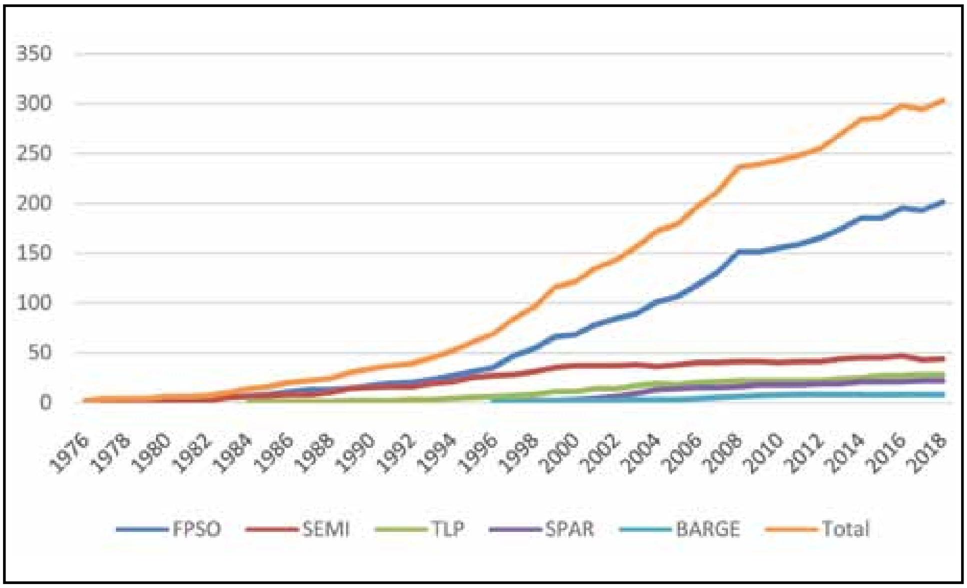
Contracts for 96 FPSOs were placed between 2009 and 2018 – an average of just under 10 FPSOs annually. But the average disguises significant variation in ordering pace. The high of 22 contracts was reached in 2010 when Petrobras ordered the hulls for eight serial FPSOs (two were subsequently canceled). In 2016 there were no orders. In both 2017 and 2018 contracts for nine FPSOs were placed.

The nine FPSOs ordered in 2018 are to be employed in water depth ranging from 32 meters (Area 1 FPSO off Mexico) to 1,700 meters (Tanin/Karish FPSO off Israel). Six of the orders utilize new purpose-built hulls – including a speculative FPSO hull ordered by SBM. Three are conversions or modifications of existing FPSOs. Two of the 2018 contracts – an FPSO for use by ExxonMobil offshore Guyana and an FPSO for use by BP on an LNG project offshore Mauritania/Senegal – are front-end engineering design (FEED) contracts structured to morph into engineering, procurement and construction (EPC) contracts.

### FPSOs now being built

Seventeen FPSOs are currently on order. Five are in the fi-

**40 YEARS+ OF FPSO GROWTH (excludes FLNG/FSRU)**




**STATUS OF 102 FPSO PROJECTS AS OF J**


Source (all charts): IMA/World Energy Reports Database nal stage of completion, with delivery scheduled by end-2019. Another two are scheduled for completion in 2020. The remaining 10 are in an early stage of construction with delivery planned in 2021/22.

Five (30%) of the FPSOs being built are for use offshore Brazil. The rest are for use offshore Northern Europe (three), Guyana (two), West Africa (two) and Mexico, Israel, China and Malaysia (one unit each). The remaining unit is being built on speculation and, at the moment, has no field assignment.

Ten of the FSPOs are being built on new hulls, while the other seven are conversions or upgrades to existing units.

China has become the major location for FPSO construction and conversions. Eleven of the 17 FPSOs on order are partially or fully contracted to Chinese yards. Singapore has retained second position, with four of the 17 orders. Korean yards – at least for the time being – have disappeared from FPSO fabrication. Topsides plant fabrication and integration is spread over a variety of contractors in Asia, Europe and Brazil.

**Planned FPSO projects**

We have identified 102 projects in the planning stage that could require an FPSO as a production system. Some of these are near term, some further out.

Of the total, 11 projects are at the bidding or contract negotiation stage. Another 10 are in the near-term investment queue, and four are in FEED.

Another 50 projects are further out in the planning stage – either in development concept definition (28), E&P (19) or commercial framework negotiation (three).

The remaining 27 projects in the planning queue are stalled. Some of these are stalled due to economics. Some are awaiting field partner or agreement on field commercial terms. Others are stalled by government opposition, field rights issues, operator failure or sanctions that prevent the project moving forward.

**Outlook for FPSO contracts**

Each year IMA/WER makes a forecast of floating production system contracts likely to be placed over the following five years. The forecast takes into account the number of projects in the planning queue and our assessment of market conditions likely to exist over the next five years.

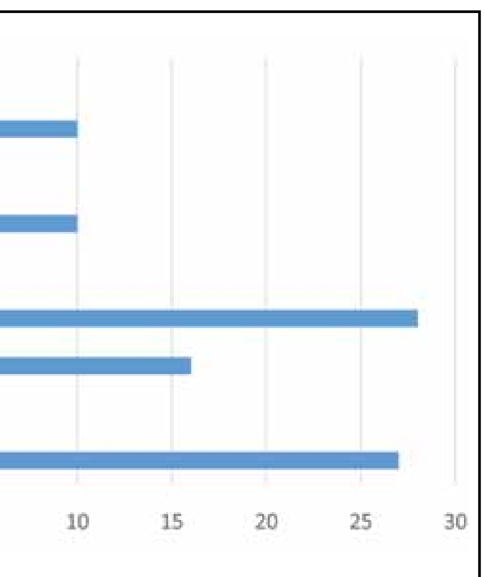
While there are more than 100 FPSO projects at various

**TREND IN NO. of FPSO IN SERVICE or AVAILABLE**

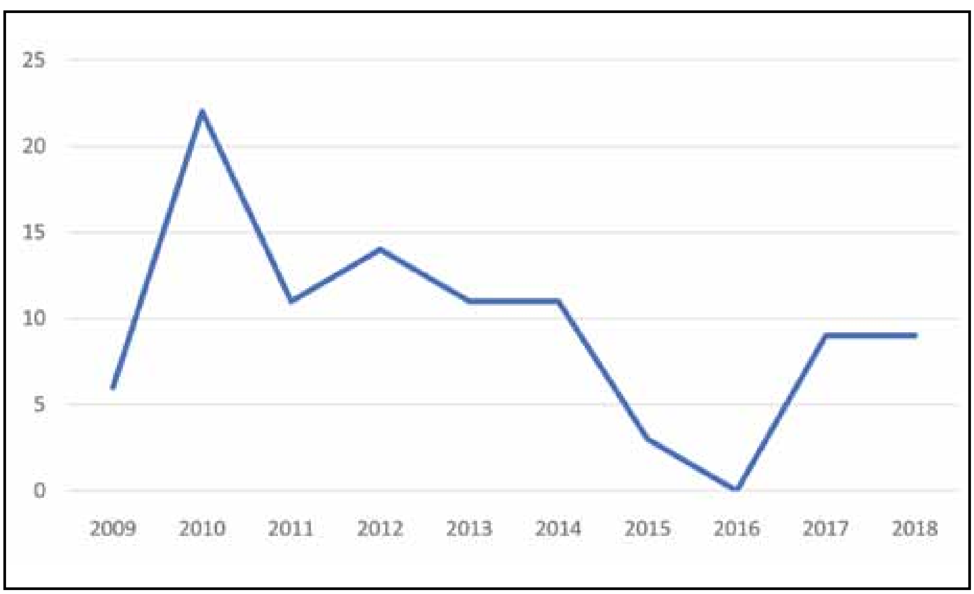
| As of End Year | Number of FPSOs | Growth Index (2009 = 100) |
|---|---|---|
| 2009 | 151 | 100 |
| 2010 | 155 | 103 |
| 2011 | 159 | 105 |
| 2012 | 165 | 109 |
| 2013 | 174 | 115 |
| 2014 | 185 | 123 |
| 2015 | 185 | 123 |
| 2016 | 195 | 129 |
| 2017 | 193 | 128 |
| 2018 | 201 | 133 |

Source: IMA/World Energy Reports Database

**ANUARY 2019**




**NUMBER OF FPSOs ORDERED, 2009-2018**



stages of development planning, for each to move to the development stage – and become a production floater order – a major investment commitment must be made. The decision to make this investment commitment is dependent on the future deepwater business environment.

In our forecast we examine 10 key drivers that will shape investment sentiment in the deepwater market and ultimately determine the pace of future floating production project starts. The key drivers are:

- Projected growth in oil/gas demand
- Future sources of oil/gas supply
- Risk of future supply disruption
- Expected oil and gas prices
- Future competitiveness of deepwater
- Capex budgets of offshore operators
- Deepwater supply chain constraints
- Access to capital
- Pace of Brazil offshore revival
- Black swan events

Based on our analysis, we are forecasting orders for 32 to 58 FPSOs between 2019 and end-2023. The most likely number is 49 FPSOs.

Brazil is expected to account for 30-35% of the projected FPSO orders over the next five years. This figure reflects the large number of deepwater projects in the planning queue in Brazil, the expected rebound of Petrobras over the next few years and the future role of international oil companies in Brazil deepwater exploration and development (E&D). The FPSOs ordered for Brazil will generally be large capacity units based on purpose built or converted very large crude carrier (VLCC) hulls.

Africa is expected to be the second largest source of FPSO activity, accounting for 25% of the orders over the next five years. Some will be large purpose built units, some mid-size converted or purpose built units and some redeployed FPSOs.

Other major sources of FPSO demand will be Northern Europe (~12%) and SE Asia/China (~10%). These will be a mixture of mid-size units, some designed for North Sea use, and include a few redeployed units. Our 2019 annual forecast report provides details for specific projects likely to generate future FPSO orders, timing of EPC contracts, role of redeployed FPSOs and composition of projected FPSO capex.



**FPSOs ON ORDER** as of January 2019

| FPSO | Country | FPSO Owner | Field Operator | Water Deth (m) | Order Date |
|---|---|---|---|---|---|
| Area 1 FPSO | Mexico | Modec | Eni | 32 | 2018 Oct |
| Carioca MV30 FPSO | Brazil | Modec | Petrobras | 2,200 | 2017 Oct |
| Fast4Ward FPSO #2 | TBD | SBM | TBD | TBD | 2018 Nov** |
| Guanabara MV31 FPSO | Brazil | Modec | Petrobras | 2,100 | 2017 Nov |
| HaiYang Shi You 119 FPSO | China | CNOOC | CNOOC | 400 | 2018 May |
| Helang FPSO | Malaysia | Yinson | JX Nippon | 90 | 2018 April |
| Johan Castberg FPSO | Norway | Equinor | Equinor | 370 | 2017 Dec |
| Kaombo Sul FPSO | Angola | Total | Total | 1,600 | 2014 April |
| Liza #2 FPSO | Guyana | SBM | ExxonMobil | 1,690-1,730 | 2018 July* |
| Liza Destiny FPSO | Guyana | SBM | ExxonMobil | 1,525 | 2017 June |
| P 68 FPSO | Brazil | Petrobras | Petrobras | 1,500 | 2010 Nov |
| P 70 FPSO | Brazil | Petrobras | Petrobras | 1,500 | 2010 Nov |
| P 71 FPSO | Brazil | Petrobras | Petrobras | 1,500 | 2017 Dec |
| Penguins FPSO | U.K. | Shell | Shell | 160 | 2018 Jan. |
| Petrojarl Varg FPSO | U.K. | Teekay | Alpha Petroleum | 167 | 2018 Oct. |
| Tanin/Karish FPSO | Israel | Energean | Energean | 1,700 | 2018 Mar |
| Tortue FPSO | Mauritania/Senegal | BP | BP/Kosmos | 200 | 2018 Dec* |

*FEED contract designed to morph into an EPC contract ** Speculative FPSO hull

Source: IMA/World Energy Reports Database

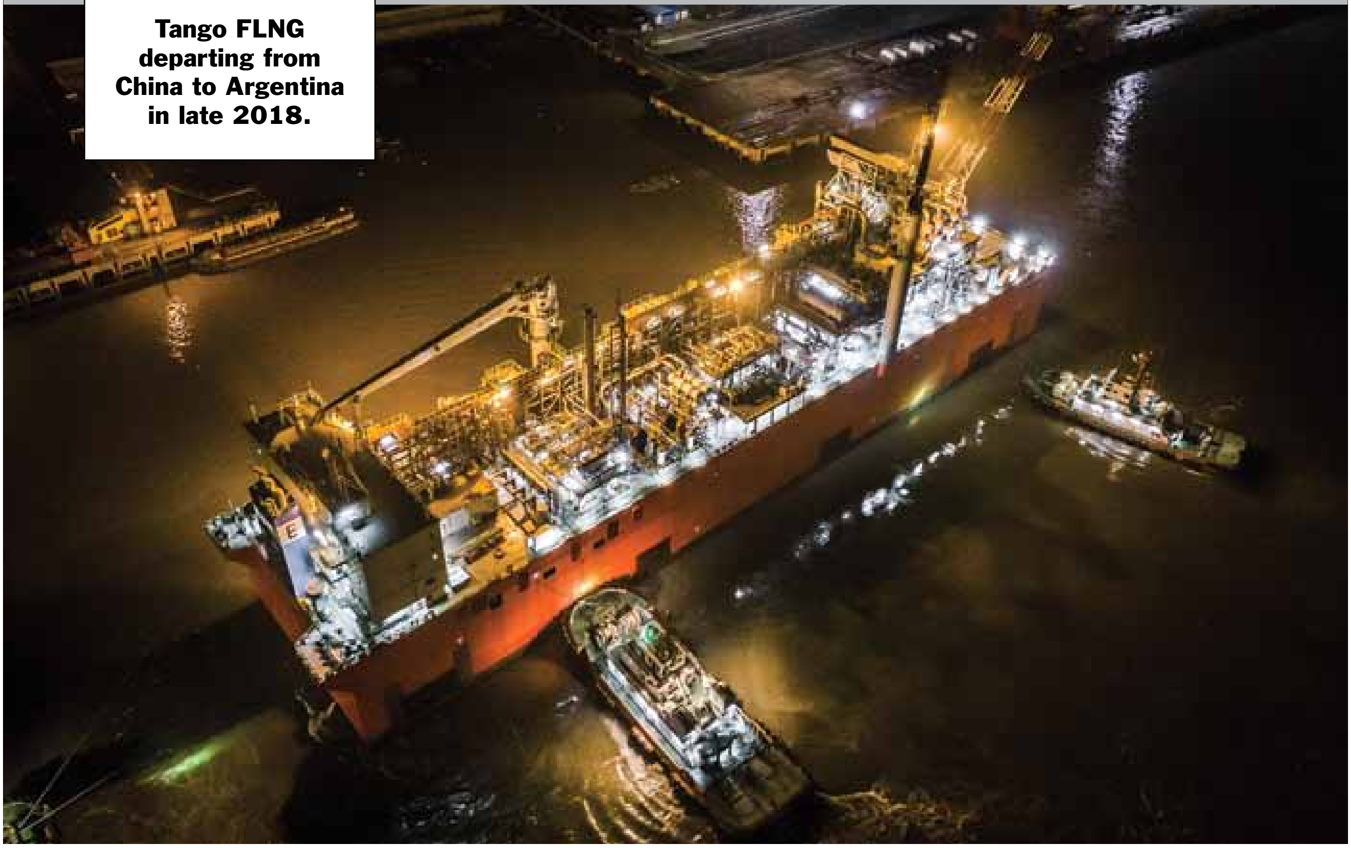
# FLNG & FSRU WHICH ONES WILL CLEAR THE INVESTMENT HURDLE?

**BY JIM MCCAUL,** IMA/World Energy Reports

IMA/World Energy Reports has just completed a 12-month detailed assessment of the floating liquefaction and regasification market. The 150+ page study examines future market opportunities in floating liquefaction and regasification, systematically assesses the universe of floating liquefied natural gas (FLNG) and floating storage regasification unit (FSRU) projects in the planning stage and assigns to each project a probability of clearing the development investment hurdle. An accompanying online database updates all FLNG and FSRU projects on a 24/7 basis. Some highlights from the study are provided here.

**Role of floating LNG plants**

Global demand for natural gas is expected to grow at an annual rate of 1.5% to 2% over the next 25 years, driven by the economic and environmental advantages of natural gas as feed for heat and power production. Much of future gas demand growth will be in locations where gas delivery by pipeline is either uneconomic or impracticable. These locations, primarily in Asia and Europe, will produce a growing requirement for natural gas in refrigerated liquid form – which will generate demand for additional liquefied natural gas (LNG) production capacity.



Tango FLNG departing from China to Argentina in late 2018.

Source: EXMAR

LNG liquefaction has historically been a land-based activity. Until three years ago, production of LNG took place entirely in land-based plants. But floating LNG plants have advantages over land-based alternatives in certain situations, and FLNGs now account for around 3% of LNG plant capacity in service or scheduled to be operational within the next two years.

FLNGs positioned offshore on a gas reservoir eliminate the need for subsea pipeline to a shore-based LNG plant. Liquefied gas can be produced on the FLNG and directly transferred to an LNG carrier for global delivery. Also, an FLNG does not occupy valuable land space, avoids some time-consuming land permitting requirements and the production unit can be relocated when the reservoir is no longer economical to produce. In general, floating plants tend to be most competitive as the development solution in projects (1) distant from shore, (2) on smaller reservoirs, (3) with difficult flow characteristics and (4) where no existing land plant is within tieback distance. But land and floating plant solutions each have merits and demerits, and the specific circumstances of the planned liquefaction project will determine the optimum development solution.

**FLNGs in service or on order**

Three of the four comlpleted FLNGs are currently in service: Prelude, PFLNG Satu, Hilli Episeyo. As of this writing, the fourth, Tango, is in transit to the production site in Argentina. Three more FLNGs are on order: Coral South, PFLNG Dua and Gimi.

The range of FLNG designs and plant capability is quite diverse. Shell's 488- by 74-meter Prelude, which began operations off Australia in December 2018, has 5.3 mtpa LNG/LPG/condensate production capability. Prelude has the distinction of being the most expensive vessel (of any type) ever built. Gimi, a 40-year-old LNG carrier being converted by Golar to a 2.5 mtpa FLNG, is the first of several FLNGs to be used by BP to develop deepwater gas/oil discoveries offshore Mauritania/Senegal. It is similar to the Hilli Episeyo FLNG now operating offshore Cameroon. Tango, a purpose-built 0.5 mtpa LNG production barge owned by Exmar, will be used for seasonal LNG production in Argentina.

**FLNG projects in the planning queue**

Looking forward, 28 floating liquefaction projects are at various stages of planning and design. Eleven of these projects are in Africa, seven in Australia/Southeast Asia, five in North America and five in other areas of the world. While all have the potential of becoming FLNG contracts, not all will move to development. Some, perhaps many, will not even make the investment hurdle.

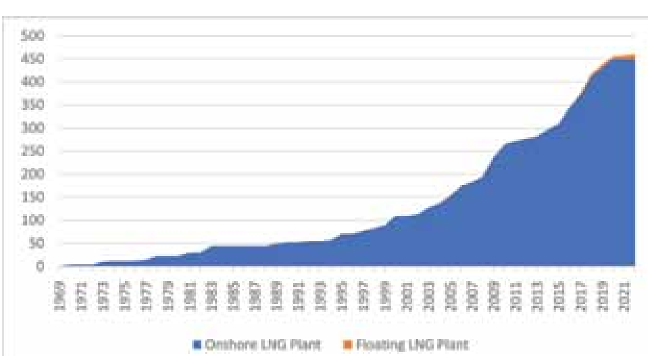
Employing a qualitative analysis that reflects lessons learned from post-final investment decision (FID) FLNG projects, we have examined each floating liquefaction project in the planning stage to determine whether the project has a strong, fair or weak probability of moving forward. The evaluation methodology takes into account the key success factors that influence the project investment decision, including:

Drivers of project economic health

- gas processing requirement
- gas quality- liquids presence
- upstream location
- FLNG location
- alternative gas commercialization possibilities
- transport distance to the Chinese gas import market

**Cumulative Growth in LNG Liquefaction Capacity**

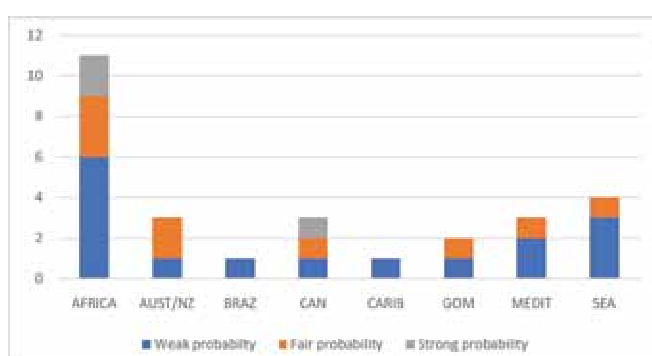
*(Includes LNG plants under construction)*




Source: IMA/WER database, International Gas Union, GIIGNL, company records

**FLNG Projects in the Planning Queue**

*& Probability they Clear the investment Hurdle*




Source: IMA/WER Floating LNG Database

Stakeholder overlay considerations

- strength of the project promoter
- strength of offtake buyer
- government support for the project
- ease of doing business in the resource country

Based on our success factors assessment, three of the planned projects in the planning queue have a strong probability (~80%) to proceed to development, nine have a fair (~50%) probability and the remaining 16 projects have a weak probability (~30%).

BASED ON OUR SUCCESS FACTORS ASSESSMENT, THREE OF THE PLANNED PROJECTS IN THE PLANNING QUEUE HAVE A STRONG PROBABILITY (~80%) TO PROCEED TO DEVELOPMENT, NINE HAVE A FAIR (~50%) PROBABILITY AND THE REMAINING 16 PROJECTS HAVE A WEAK PROBABILITY (~30%).

The three projects rated strong have full government support, strong offtake buyer, rich gas with a local propane/butane market and relatively few technical barriers. Some of the projects with weak probability need to overcome host government opposition to offshore LNG production. Others are rated weak due to financing hurdles.

For example, in our evaluation of the Greater Tortue project in Senegal/Mauritania we gave a positive rating to most of the project attributes. The upstream site is in deep water, which is a negative. But this was offset by the lack of alternative commercialization options apart from LNG, support of the two governments and a determined BP as development operator and offtaker. Overall, we gave this project a strong probability of proceeding to development. In December 2018 BP made the FID, and the initial FLNG is under construction.

In contrast, we rated the Fortuna FLNG project in Equatorial Guinea as having a weak probability of moving forward to development. While there were some important positives, the success potential was negatively impacted by technical risks associated with its deepwater location, a high methane percentage that lowered potential revenue as there were no liquids to sell and relatively weak financial strength of the developer. This project was recently shelved and the developer took a $610 million impairment charge.

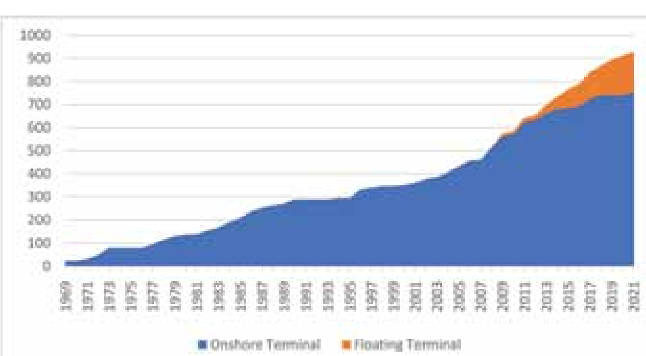
**Role of FSRUs**

As the LNG trade expanded globally since the 1960s, so did requirements for import terminals to store and regasify LNG. The number of import terminals roughly doubled between 1980 and 2000 – and quadrupled between 2000 and 2019. In 2000 five countries had LNG import terminals. Now 43 countries have the ability to import and regasify LNG.

Until 14 years ago, all LNG regasification terminals were land-based facilities. But floating LNG terminals have been gaining market share since Excelerate's Gulf Gateway offshore terminal was installed in the Gulf of Mexico in 2005. Floating regasification terminals now account for around 15% of global LNG regasification terminal capacity – and the market share percentage will increase to around 18% by 2022 counting terminals now under construction.

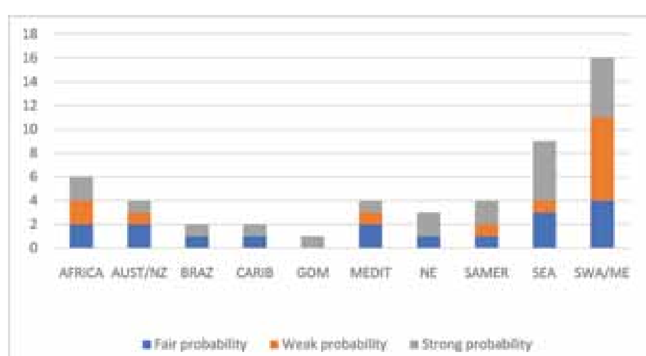
Floating LNG import terminals have a number of advantages over land terminals. Perhaps the biggest advantage is the ability to minimize first cost by leasing the FSRU rather than

**Cumulative Growth in LNG Regasification Capacity**
*(Includes terminals under construction)*




Source: IMA/WER database, International Gas Union, GIIGNL, company records

**FSRU Terminals in the Planning Queue**
*& their Probability to Clear the investment Hurdle*




Source: IMA/WER Floating LNG Database

investing in a fixed land facility. Other advantages include the terminal can generally be built quicker, FSRUs can be relocated when the import requirement changes and the unit can be used for seasonal demand peaking and employed as a transport carrier in off-peak periods. Another advantage of FSRUs is they arrive on site as finished, turnkey regasification units requiring only hook up to the gas delivery pipeline (at least that's the plan).

BASED ON OUR ASSESSMENT OF THE 51 FSRU TERMINALS IN THE PLANNING QUEUE, 21 HAVE A STRONG PROBABILITY (~80%) TO PROCEED TO DEVELOPMENT, 17 HAVE A FAIR PROBABILITY (~50%) AND 13 A WEAK PROBABILITY (~30%).

**FSRUs in service or on order**

Twenty-nine FSRU terminals are in operation and another 17 FSRU terminals are under construction. Of the FSRUs in operation, nine are in Southwest Asia, six in the Mediterranean, five in South America, four in Southeast Asia and five elsewhere. A few of these terminals are a combination of floating storage with land regas plant.

Most of FSRUs in service are essentially standard LNG carriers fitted with a modular regasification plant. Newer FSRUs generally have capacity to store 160,000 to 170,000 m3 of LNG and are capable of providing 600+ mmcf/d gas offtake. A few FSRUs with more than 200,000 m3 storage have been built. There has been recent interest in building small FSRUs to use as terminals with low gas import requirement.

**FSRU terminals in the planning queue**

Looking forward, 51 additional FSRU terminals are at various stages of planning. Sixteen of the planned terminals are in Southwest Asia, nine in Southeast Asia, eight in South America/Caribbean, six in Africa and 12 are in other locations.

We have used a similar methodology to evaluate the likelihood of planned FSRU terminals clearing the investment hurdle. The key success factors include:

Drivers of project economic health
- gas import demand driver
- need for single or multiple gas offtakers
- potential alternative sources of future gas supply
- infrastructure requirements

Stakeholder overlay considerations
- strength of the project promoter
- strength of gas off-take buyer
- government support for the project
- ease of doing business in the resource country

The success factors for FSRU terminals more heavily reflect the commercial aspects of the project – especially the ability to obtain project financing, which can be very difficult when terminal revenue is dependent on local offtakers. Several FSRU projects in which we have been involved hit a barrier when the offtaker take-or-pay contract was not acceptable to prospective lenders and/or the government was not willing or able to provide a sovereign guarantee for the offtake contract.

Based on our assessment of the 51 FSRU terminals in the planning queue, 21 have a strong probability (~80%) to proceed to development, 17 have a fair probability (~50%) and 13 a weak probability (~30%).

Strong FSRU projects generally have a powerful promoter, strong offtaker, moderate infrastructure requirement and are in a country where it is relatively easy to do business. Uniper/MOLs proposed FSRU terminal in the port of Wilhelmshaven is an example of a strong project. While the terminal will need to compete with pipeline gas, the project is backed by two strong players, terminal infrastructure needs are minimal, Germany is a relatively easy country in which to do business, LNG bunkering is a growing activity in Northern Europe and the project is driven by a need to have alternative gas supply sources for energy security.

Many weak projects have alternative gas sources (some being developed offshore), face financing barriers due to weak promoter and/or offtaker and/or would need relatively extensive infrastructure improvements to support a terminal.


Source: Höegh LNG

Source: BP

# IRM @ MAD DOG

**BY JENNIFER PALLANICH**

Keeping operations humming on an oil production spar with an integrated drilling rig requires a lot of planning. The inspections, repairs and maintenance plan for the deepwater Mad Dog facility adheres to BP's risk-based approach but is tailored to specific risks inherent on the facility and in the region.

BP's Mad Dog production unit, situated in 1,400 meters water depth in the hurricane-prone Gulf of Mexico, is unique to the operator for two reasons: it's a spar, and it has an integrated drilling derrick onboard.

The integrated drilling rig complicates the inspection, repair and maintenance (IRM) program for the facility, said Scott Steel, BP's area operations manager for Mad Dog. A main goal is to safely maximize uptime, so nonintrusive inspections are preferable.

**BP's Mad Dog deepwater production unit in the Gulf of Mexico has been onstream since 2005.**

"A lot of our challenge is simultaneous operations and how to execute them most effectively and efficiently," Steel said. "We spend a lot of time planning our way through things," so work can be done without disrupting operations.

Taking vibration readings, changing oil and painting are all activities that can be done while the facility is online.

But sometimes the risk or procedures are such that a shutdown is necessary. When that's the case, the work often is scheduled to occur during a turnaround. Such activities may include internal vessel inspections, pump replacements, control system replacement or upgrade, and compressor overhauls.

The Mad Dog turnaround in May and June of 2018 saw the replacement of the ignition system for the flare and the change out of lifeboats for bigger ones.

"We also took the opportunity to replace valves and other elements," Steel said, citing the changing of shutdown valves and solenoids for higher reliability.

Usually, there are one or two drivers for scheduling a turnaround, he said, and "everything else is risk assessed and placed into it."

A fact of life for operations in the Gulf of Mexico is hurricane season, and a hurricane threatening the Gulf prompts operators to shut in production units in and near the storm's path.

"We have to manage those and monitor while the hurricanes pass and inspect when we come back up," Steel said.

Flir cameras, which are part of the normal operations maintenance program for detecting leaks, are always used after hurricanes to make sure everything is safe before resuming production, he said. "It's a clever technology, very useful."

Source: BP

AS TECHNOLOGY ADVANCES, IT ALLOWS US TO DO DIFFERENT THINGS, TO KEEP PEOPLE SAFER, TO DRIVE UP RELIABILITY, TO DETECT EARLY ON POTENTIAL ISSUES THAT WE CAN RECTIFY AND BECOME MORE EFFECTIVE.

**SCOTT STEEL**, BP'S AREA OPERATIONS MANAGER FOR MAD DOG

**Risk-based approach**

BP's risk-based approach to IRM work on equipment is global and rolls down to the different regions. In general, BP identifies the potential risk of having an equipment issue, what the potential results are, and what can be done to prevent or mitigate the problem. Often, Steel said, there are multiple options to mitigate potential risks through the IRM program.

For example, if there is the risk of internal corrosion in a line, a standard mitigation is to inject corrosion inhibitor and monitor the corrosion in lines to ensure an effective amount of inhibitor is injected. This type of program tends to be iterative, Steel said, as the team continuously makes adjustments based on the latest data.

With a pump, the standard protocol might be to monitor performance and carry out maintenance if it fails to meet performance criteria. For equipment, Steel added, a well-thought-out spares program can make a big difference because when a spare part is on hand, it changes the level of risk.

"The sparing you have set up will dictate how you treat various pieces of equipment," Steel said. Sparing refers to the amount of redundant equipment, so if BP has two pumps but only needs one to run, BP has a spare, making it possible to change over without impact.

But risk also surrounds the actual execution of IRM operations because in some cases personnel might have to use ropes or scaffolding to gain access to the site.

"We try to be evergreen about our program, and watch equipment performance and make adjustments," Steel said.

In general, that could mean considering the age of equipment and determining whether it makes more sense to maintain it or replace it with a newer item of higher reliability.

When it comes to switching out equipment, he said, items like fire and gas detectors are often on the list.

"It tends to be more the electronic items that go into obsolescence," he said.

That said, the offshore operating environment can be both humid and saline, which is tough on metal surfaces.

Automatic ultrasonic testing makes it possible to see if vessels and pipes are suffering from internal corrosion.

"One of the things we've learned to do and manage is fabric [deck] maintenance," Steel said.

When the time comes to blast and clean the equipment ahead of repainting, BP uses a HydroCat Surface Preparation System. This high-pressure robot creeps along the surface of the deck and cleans off the metal, which helps keep people

**Mad Dog @ a Glance**

| | |
|---|---|
| Water depth: | 1,400 meters |
| Location: | Green Canyon blocks 825, 826 and 782 |
| Gross estimated reserves: | 200 to 450 million boe |
| Operator: | BP with 60.5% |
| Partners: | BHP Billiton with 23.9%, Chevron with 15.6% |
| Discovered: | 1998 |
| Onstream: | 2005 |
| Production facility type: | Spar |
| Production capacity: | 100,000 b/d of oil and 60 mmcf/d of natural gas |

away from that execution risk, he said.

Some facilities use other crawling robots for inspections, and Steel said he is considering some of those options for Mad Dog. Mini-ROVs can do internal hull inspections, he said, "which is really good." And drones conduct flare tip inspections at Mad Dog.

A host of technologies can be used in ways not initially considered with the original design, he added.

A prime example of that is a bit of software called Return to Scene (R2S). Originally used for law enforcement, R2S eventually it made its way into the oil and gas space. The technology captures high-definition pictures of what something on the facility looks like, then pulls in external assistance with the combination of R2S and onshore engineers. Mad Dog was the first facility in the region to pilot R2S and has been using it since 2013.

Another useful IRM software that the supermajor uses is Plant Operations Advisor (POA), which BP developed with Baker Hughes, a GE company. POA monitors the overall health of platform topsides. POA relies on analytics to track past issues and flag potential future issues.

New technologies are appearing all the time, he noted. Mad Dog hasn't yet taken up augmented reality or virtual reality for IRM work, Steel said, but he doesn't rule it out as a future tool in the toolbox.

In 2014 a Mad Dog partner offered to share performance data with BP, and BP reciprocated.

"We dug into [their data] to see what they do differently so we could make improvements." Based on that information, Steel adds, "We made some improvements around some instrumentation problems we'd been having" related to obsolescence.

It all comes down to continuous improvement, he said.

"As technology advances, it allows us to do different things, to keep people safer, to drive up reliability, to detect early on potential issues that we can rectify and become more effective," Steel said.

# IRM TECH TOOLS

### AUT

An inspector carries out automatic ultrasonic testing with a rotoscan unit. While this is from one of BP's operations in Egypt, it is the same method employed at Mad Dog.

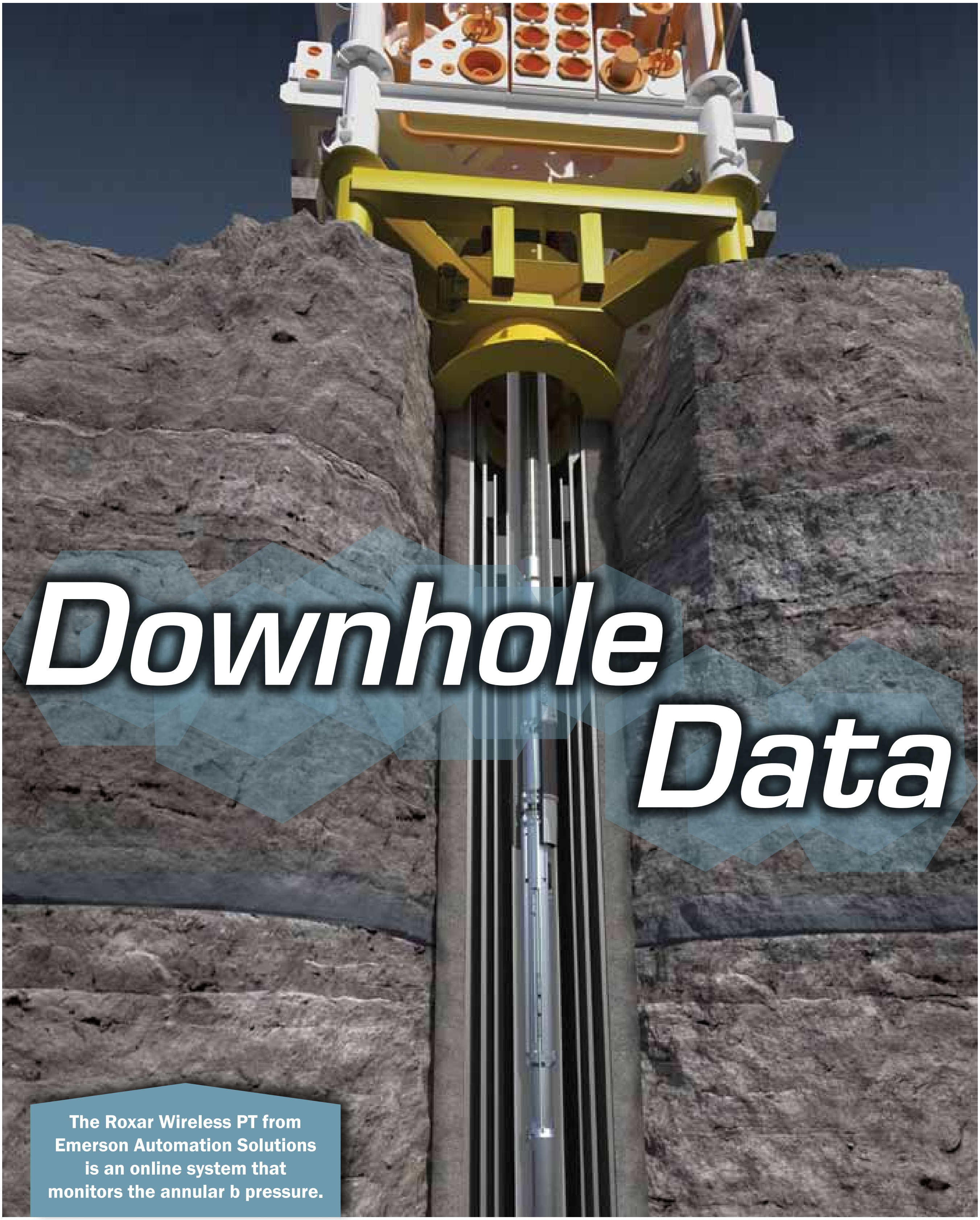
### DRONES

BP uses drones to inspect areas that are difficult to access, such as flare tips. Shown here is a drone inspection team at Thunder Horse.

### MAGG CRAWLER

Mad Dog uses crawlers to carry out certain inspections. Shown here is the Magg-HD crawler conducting an inspection at Thunder Horse.

Source: BP




The Roxar Wireless PT from Emerson Automation Solutions is an online system that monitors the annular b pressure.

Source: Emerson

*Forewarned is forearmed, an adage that is particularly true when it comes to deepwater drilling. Offshore drillers are increasingly relying on existing and new downhole data technologies to make real-time decisions and keep operations safe, writes Jennifer Pallanich.*

Complex wells and reservoirs combined with the high cost and risk of offshore operations all drive the need for access to extensive downhole data, and service companies are answering the call.

One of the newest technologies for obtaining downhole information minimizes the use of rig time for wireline operations to help operators increase operating efficiency while decreasing the cost of well construction.

Ron Balliet, Halliburton's global product champion for magnetic resonance, said the Xaminer Magnetic Resonance (XMR) service represents a "revolution in formation resolution."

The XMR service uses a downhole sensor rated to 35,000 psi and 350 degrees Fahrenheit to provide nuclear magnetic resonance (NMR) measurements and deliver formation data including 2D and 3D fluid characterization, carbonate pore-size classification, unconventional analysis and permeability. According to the service company, XMR can acquire about eight times more data with less than half the power of traditional sensors and can be deployed in nearly every openhole logging environment.

Some reservoirs are composed of thin beds, so operators want a sharp vertical resolution, and extremely small pore sizes are not uncommon, so it is necessary to take measurements quickly. Reducing the antennae aperture and shortening the inter-echo spacing are design features employed to improve small pore size resolution and improve the vertical resolution.

Balliet said the magnetic resonance helps highlight the reservoirs that will best produce and are most commercial by showing not just the reservoir delineation but also differentiating oil, gas and water.

A single sensor is suitable for all applications and hole sizes from 5 7/8 inches to 17 1/2 inches, Balliet said. It can log three times faster than Halliburton's existing technology, he added.

XMR acquires reservoir information in a single pass, and it can log up and down a well. Operators can acquire a large amount of NMR information in one trip.

The software that runs and controls the sensor, as well as NMR Studio, Halliburton's analysis software for nuclear magnetic resonance data, were developed in parallel with the tool. Balliet said the algorithms are all new.

"This is a unique platform that fits this sensor and is designed for this purpose. The analysis software provides quality control and multiple types of NMR analyses," he said.

Inversion products provide details on oil volume, gas volume and oil viscosity, he said. Together, the software sets the stage to feed all the data into various integrated analysis platforms, he said.

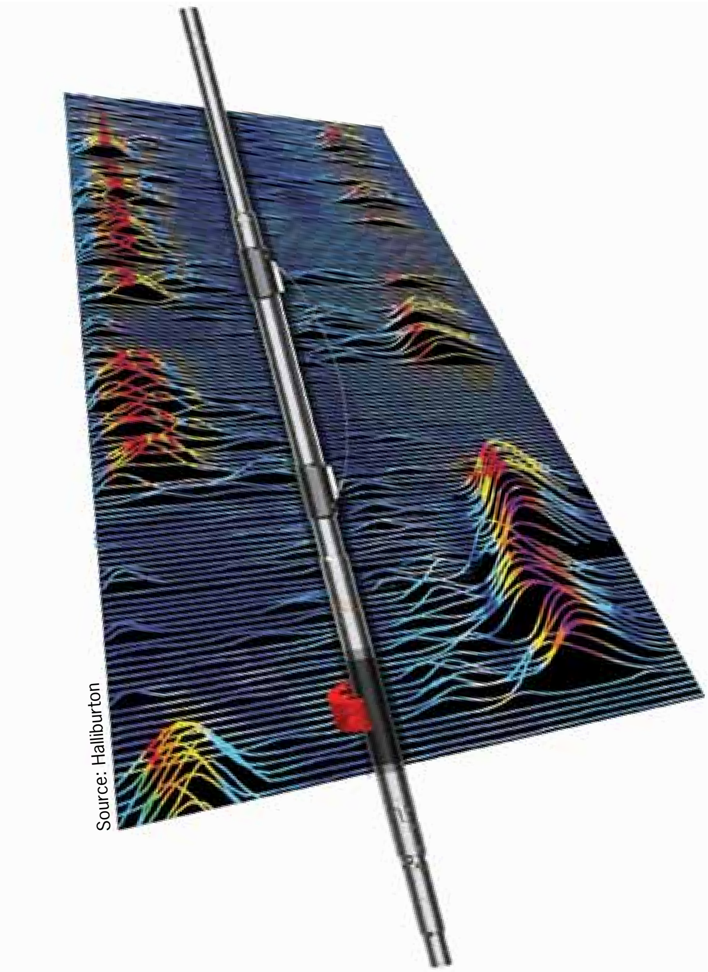

Source: Emerson

"GOING THAT ROUTE IS MORE EXPENSIVE AND TAKES A LONGER TIME. YOU'RE LATER TO MARKET DOING IT THAT WAY, BUT WHEN YOU GET THERE YOU HAVE A BETTER PRODUCT."

**– TERJE BAUSTAD**, EMERSON AUTOMATION SOLUTIONS

The Xaminer was over five years in the making and has been used to log several 9,000-meter deep wells in the Gulf of Mexico. One of the challenges unveiled during field testing was how to best deploy the sensor to keep it against the wellbore wall.

Another difficulty in developing the sensor was "taming the inter-sensor interference," Balliet said. The solution came in the form of a series of filters that keeps other



Source: Halliburton

Halliburton's XMR service can acquire about eight times more data with less than half the power of traditional sensors and can be deployed in nearly every openhole logging environment.

Source: NOV

wireline sensors from interfering with this one and vice versa, he added.

Halliburton commercialized the service in 3Q 2018.

The service company deployed the sensor in a 25,700 psi and 31,860 ft MD Gulf of Mexico well with temperatures of 340 degrees Fahrenheit in 2,100 meters of water. An NMR log of such a well with existing technology might take 24 to 30 hours, Balliet said, but even logging on the way down and performing an insurance log on the way out, the Xaminer cut that time in half.

"The operator feels this is about the best NMR data they've ever had," he said.

Halliburton will deploy the sensor globally in 1Q 2019.

## Continuous pressure monitoring

With the complexity of reservoirs and well construction, combined with the high costs of working offshore and regulatory requirements, operators are seeking ways to continuously monitor each well's barrier integrity.

The conventional method has been to verify the integrity at specified intervals by shutting in the well, thereby deferring production. An alternative to periodic monitoring is a continuous method with a life of well solution like the Roxar Wireless PT (WiPT) from Emerson Automation Solutions. WiPT is an online system that monitors the annular b pressure. It is powered from the surface with an inductive coupler, rather than

A driller interacts with the NOV drilling interface.

Source: NOV

*"THEY WANT ACCURATE INFORMATION ABOUT THE CONDITION OF THE WELLBORE, AND THE ABILITY TO KNOW WHAT'S GOING ON SO THEY CAN TAKE STEPS TO PREVENT A WELLBORE INCIDENT."*

**– STEPHEN BERKMAN**, NOV

batteries, which extends the lifetime of the tool.

WiPT is rated for operations to 400 degrees Fahrenheit and 10,000 psi. Terje Baustad, principle technology advisor for flow measurement at Emerson, said from the outset the company designed the product for high-pressure, high-temperature (HPHT) applications.

"Going that route is more expensive and takes a longer time. You're later to market doing it that way, but when you get there you have a better product," Baustad said.

Such systems can provide dynamic data about a well as the field evolves, ensuring continuous monitoring of barrier status and helping guide future well placements and production plans, Baustad said.

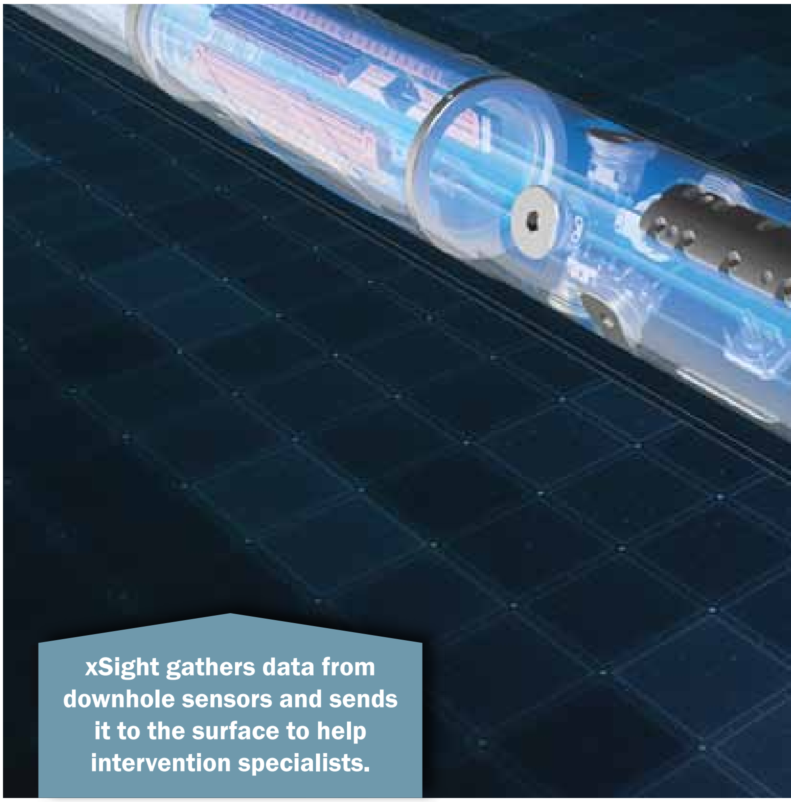
To date, Baustad said, Emerson has only run WiPT offshore Norway, where regulatory requirements and customer focus on maximizing production drive annulus B monitoring, but the company is "engaged with Gulf of Mexico and Middle East customers."

The WiPT system uses two tool joints, each about 2 meters long, with an outside diameter (OD) not more than the equivalent of the standard collar OD.

"We minimized the number of components to eliminate as many of the failure-causing mechanisms as we could," Baustad said.

The WiPT sensor is coupled to an antenna system and the first casing joint is hermetically sealed with electron beam welding.

Source: BHGE



Source: BHGE

xSight gathers data from downhole sensors and sends it to the surface to help intervention specialists.

*"IF YOU SEE A LOT OF VIBRATION, YOU CAN MAKE ADJUSTMENTS TO YOUR OPERATIONS. YOU CAN MILL FASTER BY 50% BY MAKING ADJUSTMENTS BASED ON DOWNHOLE DATA."*

**– ASHTON DORSETT**, BHGE

The casing joint is run and placed in the well, but no sensor data is sent at this point. When the reservoir section is drilled and completion is complete, a wired node is placed on the production tubing, along with a reader system and antenna. The reader is placed at the same depth in the well as the previously installed casing antenna. Once the antenna on the production tubing powers up, it powers up the sensor on the outside the casing via electromagnetic induction. From that point on, WiPT can read the pressure and temperature on the outside of the casing every second for the life of the well.

The system is connected to a network card in a subsea control module, which exchanges HPHT data with the sensors and surface.

The first was installed in late 2013 and early 2014 for Equinor – then Statoil – in 340 meters of water in the Norwegian North Sea.

Baustad sees a new use of the sensors as a means to bridge the upper and lower completions and handle the gauges without the need for electric so-called "wet connect" systems. The first run for that application is expected to occur in 2019 and would make it possible for the operator to monitor the pressure and temperature in both the upper and lower completion through one tool and one interface.

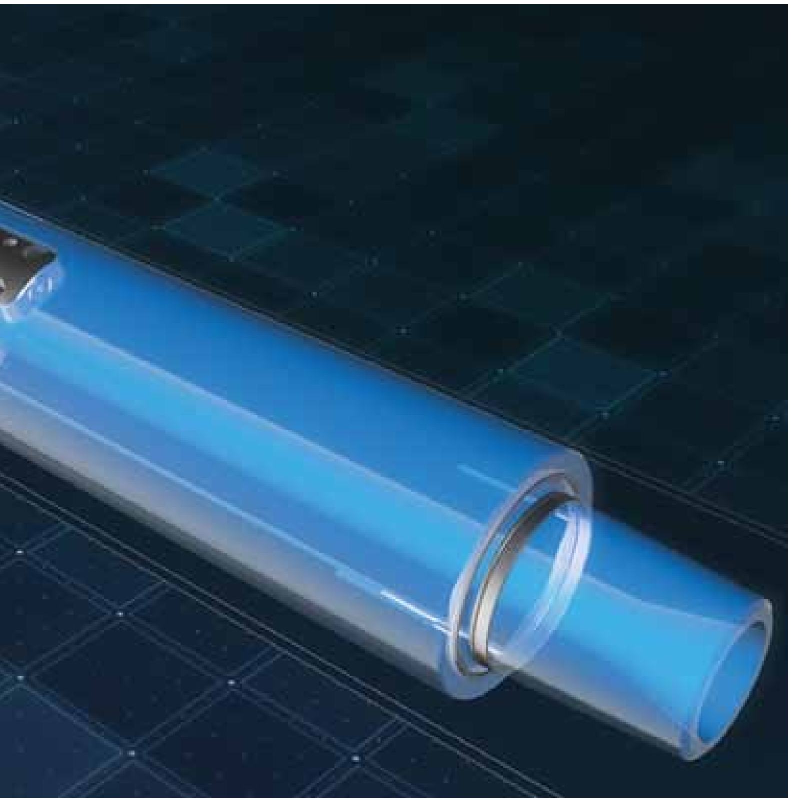
## Drilling with the lights on

Because of the risk profile for offshore drilling operations, drillers seek more and better data about the wellbore to help ensure safety and mitigate risk. Offshore, faster wells are always welcome, noted Stephen Berkman, NOV's director of global sales support for wellbore technologies, but the speed of drilling itself is not the highest priority.

"They want accurate information about the condition of the wellbore, and the ability to know what's going on so they can take steps to prevent a wellbore incident," Berkman said.

Wired pipe – specifically NOV's IntelliServ offering – can help drive drilling optimization by providing the information drillers need to make good decisions based on what is actually going on downhole, he added.

"It's drilling with the lights on," he said, something that is "irresistible to a number of offshore operators."



IntelliServ can send data at rates up to 57,600 bps straight to the surface to detail what's going on in the wellbore, he said. The sheer volume of data would overwhelm the drilling engineer, so the data feeds into the rig's control system, and proprietary software at the surface presents the data visually so the drilling engineer can see what's going on and make real-time decisions, Berkman said.

In conjunction with wired pipe, the service companies offer interfaces that allow their MWD and LWD suites to plug into NOV's wired pipe network, allowing the data to go to the surface at 57,600 bps, instead of at the normal rate offered by mud pulse telemetry of 4 bps to 12 bps. When using mud pulse telemetry, it is necessary to alternate the type of data streams being sent, so one stream might be directional data, followed by pressure data, then weight data, he said. Wired pipe is not bandwidth constrained, he added, so all data streams can flow simultaneously.

Because drillers using IntelliServ don't have to wait to receive LWD details, which is necessary with mud pulse, they can drill faster, he said. The IntelliServ data stream – which might include downhole weight on bit, torque and annular pressure – also helps drillers see vibration along the drillstring, pressure windows, general wellbore conditions and hole cleanliness.

"That's where a lot of the benefit has been seen, what they can see in real time so they can take mitigating steps," Berkman said.

IntelliServ's first commercial job was in 2006, and in 2015, based on numerous field trials, NOV introduced an upgraded version of the system, with each major system component improved.

"Version two has proven to be extremely reliable telemetry methodology," Berkman said. "We're seeing in the 95% to 98% range for uptime offshore."

## Seeing and intervening

Effectively intervening in longer and more complex laterals means having access at the surface to downhole data such as weight on bit, torque, borehole pressure, annular pressure and the casing collar location, to name a few.

"But surface equipment doesn't tell you what is going on downhole," said Ashton Dorsett, product champion for xSight smart intervention services at Baker Hughes, a GE company.

BHGE introduced the xSight platform to address those challenges. xSight gathers data from downhole sensors and sends it to the surface to help intervention specialists "reduce the time spent trying to figure out what's going on downhole," Dorsett said.

In the past, if a bottomhole assembly is left in the hole, an expert fishing hand would watch the monitor for a blip in the weight on bit, but it was necessary to pull all the way out of hole to determine if the fish was indeed on the line. Sometimes multiple trips were necessary.

"With xSight, you can see weight [changes] as small as 300 pounds, which offers significantly higher resolution compared to surface equipment that typically has a resolution of about 1,000 pounds," Dorsett said. "You know right then and there that you have it, and can confirm you have it. It takes the guess work out of it."

The service relies on a variety of sensors, including magnetometers, accelerometers and strain gauges in the xSight tool to send data uphole in real-time via mud pulse telemetry, where different surface equipment decodes the information to "see" what is happening downhole.

Services like xSight can provide downhole data for remote monitoring and decision making, he said.

The service also helps optimize milling operations.

"If you see a lot of vibration, you can make adjustments to your operations. You can mill faster," Dorsett said. Operators have seen reduction in milling "by 50% by making adjustments based on downhole data."

As the service evolves, it is likely xSight will incorporate different methods of transmitting data such as acoustic telemetry within the string – not clamped onto the pipe as some competitors do – and other sensors to measure different things of interest, he said. In addition, a strong focus will be put on advancing the ability to extract value from the data by incorporating machine learning and artificial intelligence techniques, he added.

# Prelude FLNG's Rise

Source: Shell

BY WILLIAM STOICHEVSKI

*When at plateau production, Prelude FLNG — the world's largest floating producer of liquefied natural gas, or LNG — will fill one shipborne cargo every week. As production ramps up from test volumes, there's the dawning realization of a dramatic shift in LNG markets. Criticized in Australia when gas glut threatened, Prelude FLNG plodded on from decision gate to first gas in December 2018, and now seems the master stroke that'll ensure Australia remains atop world LNG sales. Now, more than ever, large-scale FLNG looks every bit the nation-builder that oil has been.*

You can be served by excellent analytical data, but there's always uncertainty in newness — what the U.K. Health & Safety Executive once called, "the ghost in the machine", or what financial analysts call, a sudden "imbalance". And Shell (on behalf of partners Inpex, CPC and Korea Gas) appeared to delay the announcement of Prelude's first volumes despite keen interest:

"I'm sure you can appreciate the volume of global enquiries we receive on Prelude … is immense, and given the time of year, it's especially busy for those of us working," Shell spokesperson, Rachael Power, told *Offshore Engineer*. Shell staffers – on the eve of solidifying Australian floating liquefied natural gas (FLNG) supremacy – celebrated first gas, Christmas and New Year in quick succession.

Commissioning had already lasted several weeks. So, was the project's complexity and scale again beginning to tell? With Christmas on, it seemed a lid was being kept on publicity ahead of official "first gas".

Still, we sensed start-up was imminent, and it was. On Christmas Day, the world's largest offshore floating facility began filling its remaining two (of six) liquefied natural gas (LNG) storage tanks while testing the vast complex of process plant on board. Incessant delay linked to project scale seemed at an end. Commissioning in early December led to ramp-up by New Year's, and now the project is scheduled to "plateau" producing 3.6 million tonnes of LNG per annum; 1.3 MMtpa of light oil and 400,000 tonnes a year of liquefied petroleum gas (LPG) by 2020. Judging by comparable offshore gas projects – well, not quite – the first LNG carriers might expect to pick up cargoes by mid-February.

"We don't comment on costs of our projects and comparisons with others or schedule but will ship our first cargo when we are ready and it is safe to do so," Powers wrote in an email. Prelude's operations crews had already practiced ship-to-ship transfers, when export process kit was used to "import" a delivery of test volumes.

## A changed market

There is no business-as-usual for FLNG starts these days. Markets and the supply chain have changed. Now, Prelude FLNG itself has changed them further.

When the first FLNG projects were announced in 2012, "global" gas glut was the consensus picture even as LNG markets became "increasingly regional". The FLNG project count was low: a few regional projects and the prospect of Woodside's Prelude-like Browse FLNG. The upstream, FLNG supply chain – a few process-engineering alliances and the Asian yards – was still forming in 2012. Confidence, however, is back, and the LNG supply chain's growth is lifting all boats. Midstream player Awilco LNG told analysts in September 2018 that, "the market turned in 2018 after four miserable years."

So, Prelude joins a "maturing" FLNG market still fixated largely on richer gas prices in pipeline-poor Korea, Japan and China.

Prelude FLNG on station during commissioning 475 kilometers north, north-east of Broome, Western Australia

The market is enabled by a smallish network of process engineers offering front-end engineering design (FEED) although alliances once made with liquefaction contractors no figure prominently in annual reports, perhaps in light of Prelude's success. Australia can boast eight substantial LNG export installations and has surpassed Qatar, for now, to become the world's top LNG producer. China, meanwhile, is closing in on the No. 1 importer title. Soaring Indian demand, too, is good news for Prelude.

As offshore operators get to know their FLNG supply chain, China and India are rapidly amassing alternate suppliers of gas that include the ExxonMobil-led PNG LNG, Yamal and BP. With Prelude FLNG, China, Korea and Japan gain a supplier of scale to mitigate disruption and stir (or stifle) competition. Beijing' 10% tariff on U.S. LNG also bodes well for Prelude cargoes, and the Energy Information Agency says China is set to expand its already substantial 17 LNG import terminals and their combined regas capacity of 7.4 billion cubic feet per day. India, Shell's LNG Outlook 2018 says, will, by 2022, increase its LNG imports to 70 MMtpa from today's 500 MMtpa. Korea has its own "go-greener" program and wants more LNG.

## Supplier transformation

What Prelude signals the most, perhaps, is the supply chain's ability to help make large-scale FLNG as viable as newer, small-scale FLNG and even land-based LNG. At

Source: Shell

> "What Prelude signals the most, perhaps, is the supply chain's ability to help make large-scale FLNG as viable as newer, small-scale FLNG and even land-based LNG."

Prelude, Shell's worldwide gas-trading operation and Asia's proximity to Australia justify scale, and the facilities economies of scale are now insurance for when prices fluctuate.

Back in 2012 – that year of FLNG project go-aheads – the supply chain was busy protecting patents, forming alliances and learning from operators, including Shell. Whether using refrigeration tech or exhaust processes, small-scale looked more "doable". Early movers rounded on their own remedies for converting hulls to LNG holds and gas to liquids. When Prelude was an idea, new liquefaction solutions from Britain, Germany, Japan, Norway and the U.S. seemed to stimulate consortia of contractors ready to offer FEED or deliver engineering, procurement and construction (EPC).

Maritime continent Asia might lack Europe's network of interlocking pipelines, but "a FEED and an Asian yard" could get your FLNG project built, be it a converted hull or custom, barge-like vessel.

## FLNG forge

It was during that fateful six-year span of frenzied FLNG bandwagonism that Prelude FLNG – seen by some as too bold, too large or unnecessary – took shape.

In October 2012, the cutting of 260,000 metric tons of steel set the Technip Samsung Consortium to work at Samsung Heavy Industries shipyard in South Korea. Three short years later, a 488- by 74m floater left drydock for further fittings and sea trials. Shell's push to test the limits of FLNG had achieved that major milestone. Suppliers and rival operators had to marvel at the commercial power about to be harnessed. Once fully laden, the 600,000t vessel could supply all of Hong Kong's LNG needs for a year.

"Shell is uniquely positioned to make it a success given our commercial capability," Shell's head of projects and tech, Matthias Bichsel, said when local Aussie criticism was at its loudest and smaller-scale LNG projects were being sanctioned elsewhere. Bichsel and his expert teams, however, were bent on proving Prelude's economies of scale. They had the LNG pedigree. Now they had a giant marine vessel to match their "LNG, offshore, deepwater and marine technology and our proven ability to successfully deliver megaprojects."

## Tech triumph

As 2018 wound down, production wells, mooring lines, two umbilical and four risers were joined to the moored turret designed by SBM. "This is the first of what Shell expects to be multiple Shell FLNG projects," Shell proclaimed. What a difference a few years make!

In Prelude's wake, a number of other aspiring FLNG players appeared to roll-up development plans. With production plant now tapping Australia's big gas fields, Prelude's technological achievement is a high-water mark. While the tech used offshore derives from years of onshore LNG, Shell also presided over new FLNG innovations to manage sloshing in LNG tanks; the coupling between wells and LNG plant; liquids offloading; mooring systems and marine-proofing of process equipment like absorption columns and the facility's main cryogenic heat exchangers. More than 600 engineers and 5,000 other workers from hundreds of suppliers provided the grind of minds and onboard cacophony that changed criticism into admiration.

**Market-changer:**
Prelude FLNG leaves SHI Shipyard in South Korea

*"This is the first of what Shell expects to be multiple Shell FLNG projects."*

Source: Shell

## Mega-turret

Prelude's arrival in Australia in July 2017 kickstarted the era of extracting and liquefying gas well out to sea for simultaneous production to market. It also started the commissioning process for a turret mooring system designed and built by Dutch SBM Offshore at the invitation of Technip. A thousand workers will recall the scale in five modules that became the vessel's 90-meter mooring column.

"The Prelude turret mooring system (TMS) represents a significant milestone in SBM Offshore's gas experience and is a testimony to our technological expertise for turrets," SBM spokesperson, Paula Blengino said. With palpable respect, she added, "The Prelude FLNG is a Shell project." The TMS's main job is to keep Prelude on-station by allowing the vessel to weathervane around its moorings. That means fewer moves to protect the facility's riser system.

Like so many Australian suppliers, SBM learned a lot aboard Prelude. Since the project, SBM, like the rest of the FLNG supply chain has matured.

"In the future, SBM Offshore will focus mainly on FLNG projects where it can add most value by acting as a main contractor, as it does successfully for the [floating production storage and offloading (FPSO)] market," SBM management had written. Medium-sized projects of "up to 2 MMtpa" were to be a focus. Today, SBM is an FPSO engineering heavyweight that appears ready to offer a standardized, ostensibly cheaper and more versatile, FLNG design akin to its floating oil production offering.

## Market growth

In November 2018, Australia overtook Qatar to become, for now, the world's largest exporter of LNG. Eight LNG projects not called Prelude – Darwin, Gladstone, Gorgon, Ichthys, Queensland Curtis, Northwest Shelf, Pluto, Wheatstone – helped bring that about.

As the Prelude FLNG Marine Terminal begins production, Chinese demand is creating a growing LNG supply gap the project will help close. It's a changed market since the days of Australia's first LNG projects, or from 2012, when FLNG was a new term.

Beyond 2018 – a year of Awilco LNG said saw 40% more LNG production – LNG carrier rates look set to rise along with LNG prices to beyond 2023 (EIA). Beyond that, LNG imports are set to more than double to 2040.

Prelude's scale should come in handy.

# PETROBRAS "A New Era Begins"

BY CLAUDIO PASCHOA

The new year began with a new government in Brazil and a new management controlling the national oil and gas company Petróleo Brasileiro. There are changes on the horizon for the company commonly known as Petrobras, but its new president Roberto Castello Branco said during his inauguration speech in January that the company will maintain its focus on the exploration and production of large deepwater oil fields in the pre-salt polygon where it will seek to accelerate the extraction of oil and gas.

"Faced with the concern about climate change and the electrification trend, we will accelerate the production of oil so that our reserves have the best possible use," said Castello Branco, noting that this will be a priority. Under the current business plan, the company's oil production in Brazil is expected to exceed 2.8 million barrels a day, on average, in 2023.

The new chief executive stressed that "what is relevant is to be strong and not to be giant" and declared that monopolies are "inadmissible" in free societies. However, he also said the privatization of the Petrobras holding company is not on the agenda for now.

On launching its business and management plan for the next five-year period, Petrobras executives said the plan assumed an average increase of $66 a barrel in 2019, $67 in 2020, $72 in 2021, $75 in 2020, to $75 in 2023. Pertaining to the current business plan approved by the previous management, Castello Branco said that in principle the program is good, but he plans to assess whether changes will be needed. The executive said the company's strategic vision will include five priorities: portfolio management, minimizing the cost of capital and incessant search for low costs and efficiency, meritocracy, workplace safety and protection of the environment.

With the expected increase in deepwater drilling and production, the last two priorities will need to be very robust, which may affect the search for lower costs. Petrobras in practice is still undergoing a recovery process because of Operation Lava Jato, which unmasked a series of corruption schemes involving company executives, politicians and large local construction companies, among others. "Today's Petrobras is much better than 2015, but there is still a lot to do," Castello Branco said. "It has been saved from the relegation of the second division, but there is still a lot to do to be a champion. A new era begins."

The national operator has earmarked $84 billion in investments between 2019 and 2023. It plans to spend $68.8 billion on its exploration and production (E&P) business, $8.2 billion on refining, transportation and marketing, $5.3 billion on gas and petrochemicals and $400 million on renewable energy sources. The new president indicated that some of these sectors with less investment may be open to foreign competition and/or involve partnerships with the state company, which is in league with the intent of the new Brazilian government. "Partnerships will always be welcomed, especially for the extraordinary opportunity to exchange ideas and experiences," he said.

A majority of funds invested in E&P will emphasize production, notably in the pre-salt where the company plans to boost output by putting an additional 13 floating production, storage


Source: Petrobras

FPSO P 69 leaving the shipyard after module integration.

and offloading (FPSO) units in production through 2023. It has yet to order seven of them. Despite delays in placing some orders, sources with access to the new management are adamant that the outstanding FPSO orders continue to be a priority.

Petrobras sources highlighted that E&P continues to be the company's most important value-generating engine, and the focus remains on the development of deepwater production, where large daily volumes are the norm and where efficient subsea systems linked to the FPSO are vital, with a variety of riser and flowline systems being tested or implemented, depending of the peculiarities of the reservoirs, subsea well dispositions and the number of deepwater wells in the system.

Petrobras is aggressively gearing up to increase its oil and gas production, which in November 2018 was pegged at 2.62 million boed, with 2.52 million boed produced in Brazil and 100,000 boed abroad. The total operated production of the company (including Petrobras and partners' share) was 3.28 million boed, with 3.15 million boed in Brazil. The figures marked a slight reduction from October 2018 mainly due to maintenance stoppages of the FPSO Cidade de Ilhabela, located in the Sapinhoá field, in the Santos Basin pre-salt, and of the platforms P-18 and P-37, located in the Marlim field, in the Campos Basin. Of note in November was the start-up of the P-75 FPSO, the second unit installed in the Búzios field, in the pre-salt of the Santos Basin.

It is understood that Petrobras is analyzing a new contracting strategy for its next FPSO vessels to operate in the pre-salt province. Industry sources have stated that the company is considering a switch from the leasing and operating format, which has recently been used for chartering large FPSOs to the Mero and Sepia fields, to the contractual modalities of engineering, procurement and construction (EPC) or build-operate-transfer (BOT). Currently, Petrobras is offering five FPSOs, two for the revitalization of the former Marlim field and one for each of the Mero, Búzios and Parque das Baleias plays under the more traditional leasing and operation

*Today's Petrobras is much better than 2015, but there is still a lot to do" …"It has been saved from the relegation of the second division, but there is still a lot to do to be a champion. **A new era begins**.*

*Petrobras President*
**Roberto Castello Branco**

Source: Petrobras

model. With this, the company would be guarding against eventual loss of competitiveness. This is because the main players are involved in three bids for FPSO charters promoted by the national operator: Mero 2, Parque das Baleias and Marlim 1 and 2. "There is the possibility that if Petrobras enters the market with one more charter, maybe there may be only one or two players in the Itapu tender," explained an industry source.

In addition to Modec, which has already won the Mero 1 and Sepia contracts, others including SBM, Teekay, MISC, Yinson are potential bidders. Petrobras' Director of Production & Technology Development, Hugo Repsold, said last year that the company plans to resume contracting its own FPSOs only in the case of units with operations starting in 2023. It remains to be seen if the new administration will keep to that policy, but well-placed sources indicate that a change of policy in this case is unlikely.

The Itapu pre-salt play in the Santos Basin, is in 2,000 meters water depth about 200 km from the coast of Rio de Janeiro. Its in situ volumes of 1.3 billion barrels of oil is a significant volume, yet hardly one of the largest, serving as a good example of the magnitude of even a medium sized pre-salt subsea production system. The current forecast is that the field will produce for 30 years, between 2021 and 2050. The designed production system provides for the connection of five producing wells, two water injectors and two gas injectors. In addition to the injection, the gas can be drained through the pre-salt pipeline network: Route 1 (Caraguatatuba), Route 2 (Cabiúnas) and Route 3 (Comperj,


Source: Petrobras

Pioneiro de Libra FPSO in the giant Libra pre-salt field off Brazil.

in implantation).

The P-75 was the fourth FPSO to be put into production in 2018, after the FPSO Cidade Campos dos Goytacazes in the Tartaruga Verde field, the P-69 in the Lula field and the P-74 in the Búzios field. These, together with P-67, which is already in the Lula field lease, and P-76, which went to the Búzios field in December, conclude the six systems planned for 2018 in Brazil contributing to the increase of Petrobras' production in the horizon of the 2018-2022 business and management plan. The company expects its production to grow by 10% in Brazil and 7% in general, due to the start-up of five new production units in 2018 and another three in 2019. For the period between 2020 and 2023, Petrobras expects total production of oil and natural to grow at an average rate of 5% per year.

Petrobras outlined in its 2019-2023 investment plan that it also hopes to continue partnerships and divestitures, where it sees the potential to generate $26 billion over the plan period. "These initiatives, coupled with an estimated cash flow of $114.2 billion, after dividends, taxes and contingencies, will allow Petrobras to invest and reduce its debt without the need for new net borrowing on the debt horizon plan," said a Petrobras executive in December 2018.

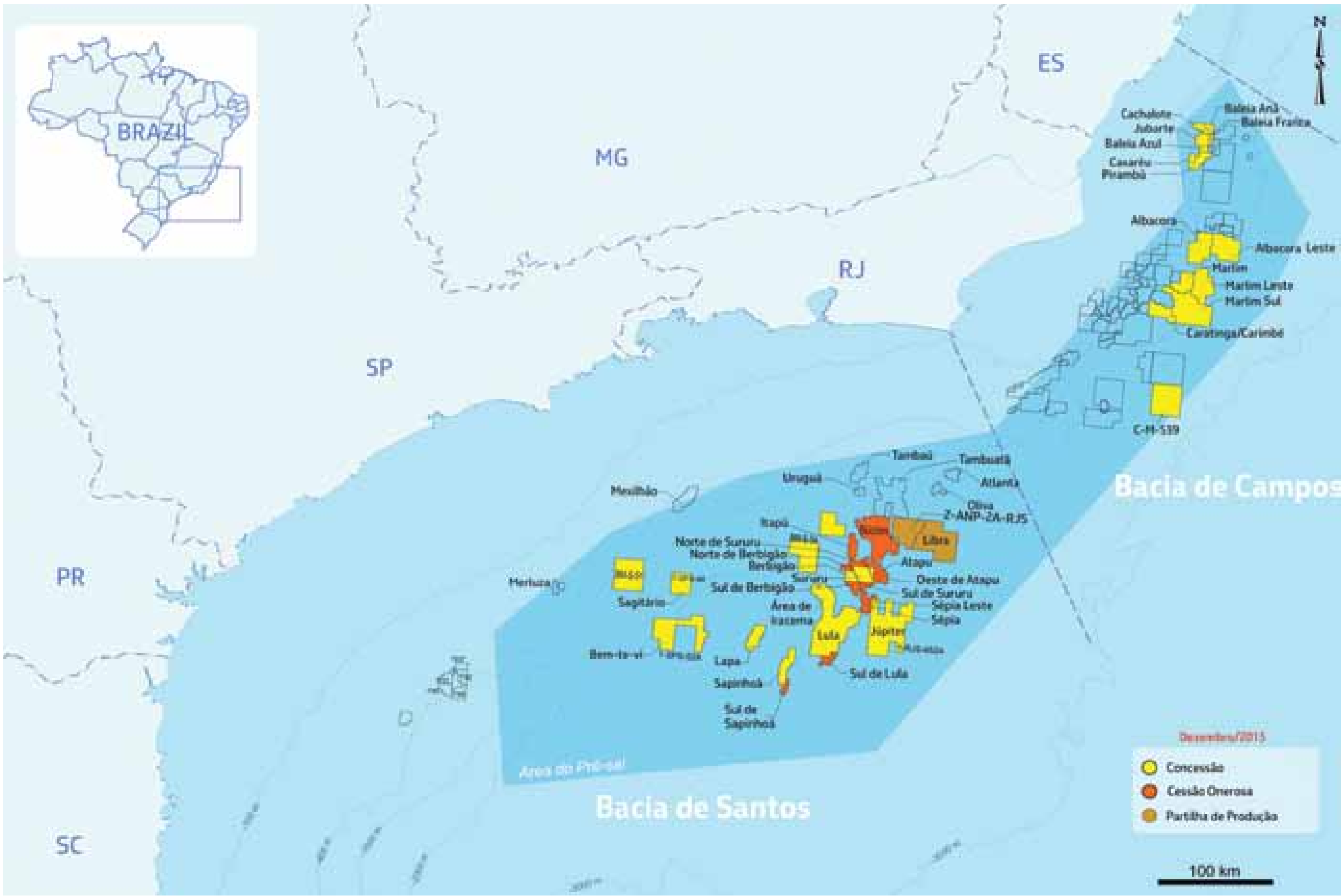
## FPSOs IN OPERATION IN THE PRE-SALT

- FPSO P-75 - (Búzios field, in the Santos Basin)
- FPSO Cidade Campos dos Goytacazes - (Tartaruga Verde field, in the Santos Basin)
- FPSO P-69 - (Lula field, in the Santos Basin)
- FPSO P-76 - (Búzios field, in the Santos Basin)
- FPSO P-74 - (Búzios field, in the Santos Basin)
- FPSO Pioneiro de Libra - (Libra block, in the Santos Basin)
- FPSO P-66 - (Lula/Lula South fields, in the Santos Basin)
- FPSO Cidade de Caraguatatuba - (Lapa field, in the Santos Basin)
- FPSO Cidade de Saquarema - (Lula field/Central Lula area, in the Santos Basin)
- FPSO Cidade de Itaguaí - (Lula field/North Iracema area, in the Santos Basin)
- FPSO Cidade de Maricá - (Lula field/Lula Alto area, in the Santos Basin)
- FPSO Cidade de São Paulo - (Sapinhoá field, in the Santos Basin)
- FPSO Cidade de Ilhabela - (North Sapinhoá area, in the Santos Basin)
- FPSO Cidade de Angra dos Reis - (Lula field, in the Santos Basin)
- FPSO Cidade de São Paulo - (Sapinhoá field, in the Santos Basin)
- FPSO Cidade de Paraty - (Lula Northeast field, in the Santos Basin)
- FPSO Cidade de Mangaratiba - (Lula field/Iracema Sul area, in the Santos Basin)

## FPSOS IN OPERATION IN THE PRE-SALT AND POST-SALT OF THE CAMPOS BASIN

- FPSO Cidade de Anchieta - (Jubarte, Baleia Azul and Baleia Franca fields, in the Espirito Santo sector of the Campos Basin)
- FPSO Capixaba - (Baleia Franca field, in the Espirito Santo portion of the Campos Basin)

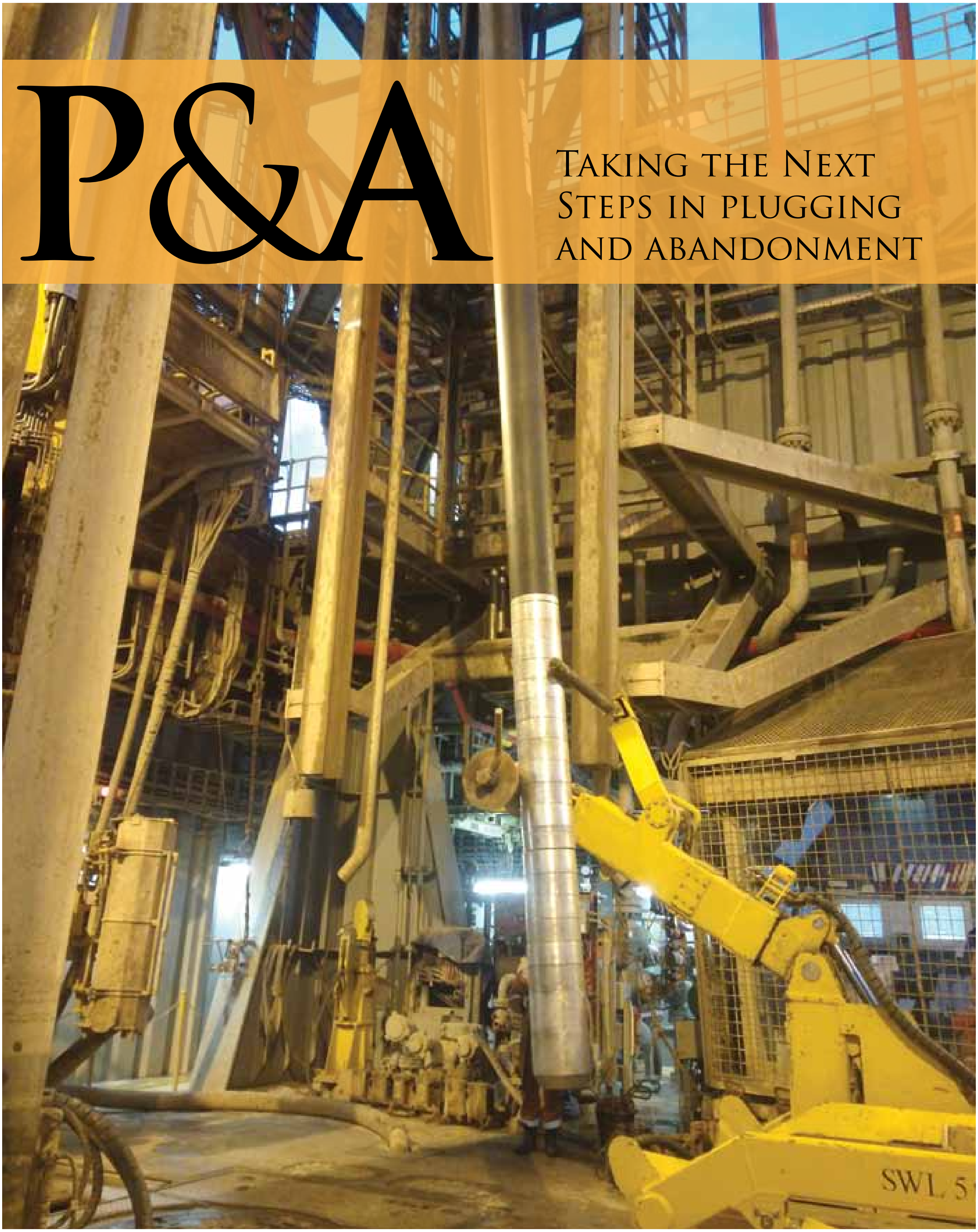
The pre-salt polygon offshore Brazil.




Source: Petrobras

# P&A

## Taking the Next Steps in plugging and abandonment



Source: Altus Intervention

**WORLD'S LARGEST:** The world's largest Bismuth plug being deployed via e-line in the Valhall field.

*New solutions which could break the plugging and abandonment mold are making their presence felt on the Norwegian continental shelf.*

**BY ELAINE MASLIN**

At some point in the future, plugging and abandonment operations (P&A) will be a regular and relatively unexciting activity for the offshore oil and gas industry; part of the decommissioning process.

But, that's in the future. Today, this activity is still something of a new challenge and there's still plenty to play for.

At the annual Plugging and Abandonment Forum (PAF) Seminar, supported by Norsk olje & gass, held in Stavanger, some of the latest advances and the challenges were laid out. There are new products entering the market, new techniques being suggested and tested, and constant learnings. There are also challenges: technical, regulatory and environmental.

In its simplest form, plugging a well means putting barriers down the well to stop anything from beneath leaking out – and the industry wants easier ways to do it, especially those that mean it doesn't need to use a rig. The challenges include verifying the quality of cement put behind the well's casing, sometimes decades ago, (and if it can't be, it has to be removed, at considerable expense) and then verifying that the new barriers are permanent, impermeable and will last.

## Reactionary

Two emerging technologies which could reduce P&A costs are Interwell's thermite plug technology, which literally burns through casing, cement and surrounding rock, to create a barrier, and BiSN's bismuth plug, which creates a metal to seal by melting bismuth.

Aker BP has put bismuth in the ground in 2018 and plans to do the same with thermite in 2019, both to test the technologies. Interwell's thermite plug uses the exothermic reaction sparked when aluminum and iron oxide are heated (using an electric heating element for downhole application), resulting in 4,500-5,000 degree Fahrenheit temperatures. The process has been used in a controlled way for decades to weld railway lines. Interwell's thermite plug has been placed in onshore wells in Canada in 2017 and onshore in Italy and in the U.K. in 2018, but not being able to view the impact it has had downhole is something of a limiting factor, said Martin Straume, P&A Engineering Manager at Aker BP, which is part of a joint industry project (JIP) testing this technology. So, in August 2018, the firm and its JIP partners, including Equinor, spent not an insignificant sum building a full-scale test cell in Norway so that it could then slice open a section of the barrier created by Interwell's thermite.

"We had never seen inside before," Straume told the PAF event. "An 8.5-in hole was drilled and a 7-in case cemented inside it. After the thermite was run, the plug was about 9-in, bigger than the drilled hole, and the 7-in. casing was gone. The whole zone was about 11 in."

Next, Aker BP took BiSN's technology a step further. BiSN's Wel-Lok M2M technology leverages the fact that bismuth has a density 10 times greater than water and, when melted, has a viscosity similar to water, so that it fills crack and fissure it finds. It then expands when it cools, by about 3%, according to the firm, creating a gas tight seal in the well. BiSN also uses modified thermite, as the heating element, which is a chemical reaction activated with 240 volts and 60 milliamps for about 15 seconds. BiSN's technology was first field trialed in 2016, in 4.5-in tubing onshore Alaska, then offshore in the Gulf of Mexico and Angola, to shut-off areas of wells where water was coming in. In 2017, the technology was used by Aker BP offshore Norway, on the Valhall field, in wells which had bridge plugs and barriers, but were leaking gas. Now, it's been trialed as

Source: Interwell

**Interwell's technology** creates a thermite reaction in the well, to seal it.

an upper barrier, again in a well on the Valhall field, creating what's been called the world's largest Bismuth plug.

The Wel-lok M2M plug was deployed on the A-30 well, which already had a cement-based lower abandonment barrier, using an E-line (a type of wireline conveyance into the well) run by Altus Intervention. Over a couple of hours, some 3,500kg of bismuth alloy was placed at 380m downhole and melted to create a 2m-long plug inside 18.625-in casing, through a section milled window cut in the 13.375-in casing. The heating element was removed at 37 minutes, before the Bismuth could set, to remove any possible leak paths it could create, Straume said.

A benefit of the Bismuth is that it effectively locks itself in place, because it expands the casing it's in, he said. This also exerts pressure on the surrounding rock, creating a tight seal. For Straume, using both cement and one or both of these new technologies could be a good solution. "If cement is used for multiple barriers in a well, it has the same failure mechanism," he pointed out. "If cement and another medium is used, there are different failure mechanisms, so you're less likely to fail across the multiple barriers."

The goal for both of these tools is helping to reduce how much steel (tubing and casing) needs to be pulled out of the wells, as well as to create long-term impermeable barriers.

## More with Modular

Operators are trying to take work off rigs, by doing as much of the work it can with wireline and coiled tubing. For the Jotun B well plugging and abandonment program, ExxonMobil and then Point Resources (which acquired the facility as part of a package in 2017) used a modular rig for the final phase of P&A operations.

Jotun B, a fixed facility in the Norwegian North Sea, had 20 wells, a platform rig that would have required significant refurbishment and the platform had limited bedspace. Using a modular rig, which could be installed on the original Jotun B drillfloor, meant it didn't have to do this refurbishment work or hire a jackup rig for the project, P&A contractor Halliburton's senior project manager Jan Tore Helgesen told the PAF seminar.

ExxonMobil also reduced the modular rig's workscope by doing wireline and coiled tubing work upfront, including perforate, wash and cementing techniques, which meant less steel had to be pulled out of the well. Explosives are used to make holes in the tubing and casing, then washes out these sections so that cement can be pumped in through all the gaps to make a plug or barrier in that section.

Source: Halliburton

**Halliburton's modular rig,** for the Jotun B P&A operations.

In total, 3,174m of tubing (over 15 wells) was perforated during 16 runs, with 67,626 holes made with perforation guns (using up some 1,887kg of explosives), said Helgesen. The electrically powered Optimus P&A unit, which has 350-metric-ton pulling capability (and can be upgraded to 500-metric-ton), then did the remaining work that couldn't be done by wireline or coiled tubing. The conductors will be removed by heavy lift vessel.

## Making an Intervention

When there's not a platform to work from, as on ConocoPhillips' MacCulloch field, a modular rig cannot be used. ConocoPhillips used a light well intervention vessel (LWIV) to remove well suspension work the subsequent semisubmersible rig campaign.

MacCulloch, which produced 120MMbbl from 1997 to 2015, when it was shut-in, was developed via 11 wells, from two drill centers tied back to the North Sea Producer floating production, storage and offloading vessel (FPSO), in the U.K. North Sea. In 2015, the wells were isolated at the Xmas trees prior to the North Sea Producer being removed. In 2017 the wells were suspended and Metrol downhole gauges were installed during the LWIV campaign. The Metrol gauges send their data to the tree, from where it's transmitted acoustically through the water column to passing vessels, so the well status can be monitored over multiple years.

Doing the upfront work with a light well intervention vessel "helped us to de-risk wells that were 20 years old, had been producing for 18 years and had no intervention history," said Alistair Agnew, ConocoPhillips. "Splitting the P&A campaign into two phases (with the ability to monitor the well barriers via the downhole gauges) also gave us more time to optimize the P&A design

**Maersk Drilling's Maersk Reacher jackup,** which undertook P&A operations on Valhall.


**Helix Well Ops' Well Enhancer light well intervention vessel,** used on the McCulloch subsea P&A campaign.


and let technology catch up." Indeed, in 2015, the base case was section milling. "Waiting opened the door to a perforate, wash and cement (PWC) solution," which had, by 2017, been tried and tested by ConocoPhililps' Norwegian business.

The firm was also able to use divers to reinstate barriers for tree cap recovery and subsequent well access, by using Helix Well Ops' Well Enhancer well intervention vessel, which has an 18-man saturation diving system – something a more conventional LWIV couldn't provide without DSV support. They ran with nine divers, working in three teams of three, which meant 18 hours a day of diving coverage.

ConocoPhillips also did its subsurface homework, which meant being able to reduce the number of barriers it needed to place. "It really starts at the subsurface, that's where we can make most savings; do a really in-depth subsurface review and understand what actually needs to be abandoned," Agnew told the PAF event. "We went from setting four barriers down to two."

The light well intervention operations were done last year. The Phase 2 rig-based work will start 2019.

## Taking a Risk-based Approach

Others are also looking to the subsurface and a risk-based approach to reduce P&A scope. Repsol and Shell took this approach as part of their P&A campaigns on Varg and Brent, respectively.

The challenge on Varg was to understand two rock formations above the Varg reservoir, called Ekofisk and Tor. These were understood to have influx potential, which could mean plugs were needed above them. Repsol used logging and scanning tools to assess the formation bond and to see if creeping shale – which sees surrounding rock tighten on the well – was evident to decide on its barrier design.

On Brent, Shell has a much bigger challenge. While Varg had 12 wells, the Brent field, operated from four platforms (one of which, Delta, has now been removed), has 154, from which about 400 wells bores run. Initially, said Alexander Watson, Shell U.K., the P&A strategy was quite prescriptive, i.e. to abandon all permeable zones, "one size fits all." In some wells, there could be two casing strings across the main reservoir and two shallow zones, which, taking a conservative approach and doing section milling and placing barriers across all three, would be a major task. "We needed something different," Watson said.

Shell looked to dual casing PWC, which hugely reduced the time it would take on each well. There are limitations to PWC, however, he said, which Shell used in 7 5/8in and 9 5/8in sections. Bigger sections would need larger perforation guns and larger fluid volumes, which may not be possible when there's limited topside facilities to handle high volumes.

But, looking for creeping, or squeezing, shale and assessing the subsurface, through logging, monitoring and modeling, also helped to reduce the number of barriers that needed to be placed.

However, "This isn't the end," Watson said. There's work around barrier verification to be done and further steps could be taken, such as moving to through tubing abandonment, which would mean tubing, as well as casing, could be left in the well, reducing the time and cost to P&A further.

## Learning by Doing

Operators are also learning by doing. Aker BP's BiSN trial on Valhall is a sideline to a larger ongoing P&A program, in tandem with a rejuvenation project on the field. Through two campaigns, starting in 2014 and 2017, Aker BP has made strides in P&A efficiency, Straume said.

During the first campaign, through 2014-2016, using the Maersk Reacher jackup rig, 12 well slots were P&A'd (amounting to 13 wells, as one had a producer and injector from it) over two years. At the start, the first well took 120 days to P&A and the fastest well was plugged in 40 days. The campaign averaged 62 days/well for these 13 wells. “If you do a P&A campaign, you have the opportunity to collect all your data, and evaluate and focus on what you can improve on,” Straume said. “That’s what we did. We gathered 1,500 learning points on the first campaign. We condensed that to 60-70 learning points and focused on reducing these further.”

The result was that second campaign, using the Maersk Invincible jackup to P&A 14 wells, saw a 52% reduction in P&A per well time; 14 were done in 13 months instead of 13 over two years. Wells with similarities were bunched together to enable a more factory style approach, Straume said, and in total some 125 well barriers were placed, 49km of tubing pulled and 2,100-metric-tons of steel removed. The rig has a main rotary table and an auxiliary working station, so it can pull out tubing and casing in stands and unscrew them off the critical path, he added. The last campaign also saw a sandwiched casing pulled for the first time and an area section milled in one run over 110m inside 13 3/8in casing, including underreaming to clean out the milled window for logging purposes.

“The learning curve has been steep,” said Karl Johnny Hersvik, Aker BP’s CEO, who also spoke at the PAF event. “If we continue, we could get to 14 days from a starting point of 120 days.”

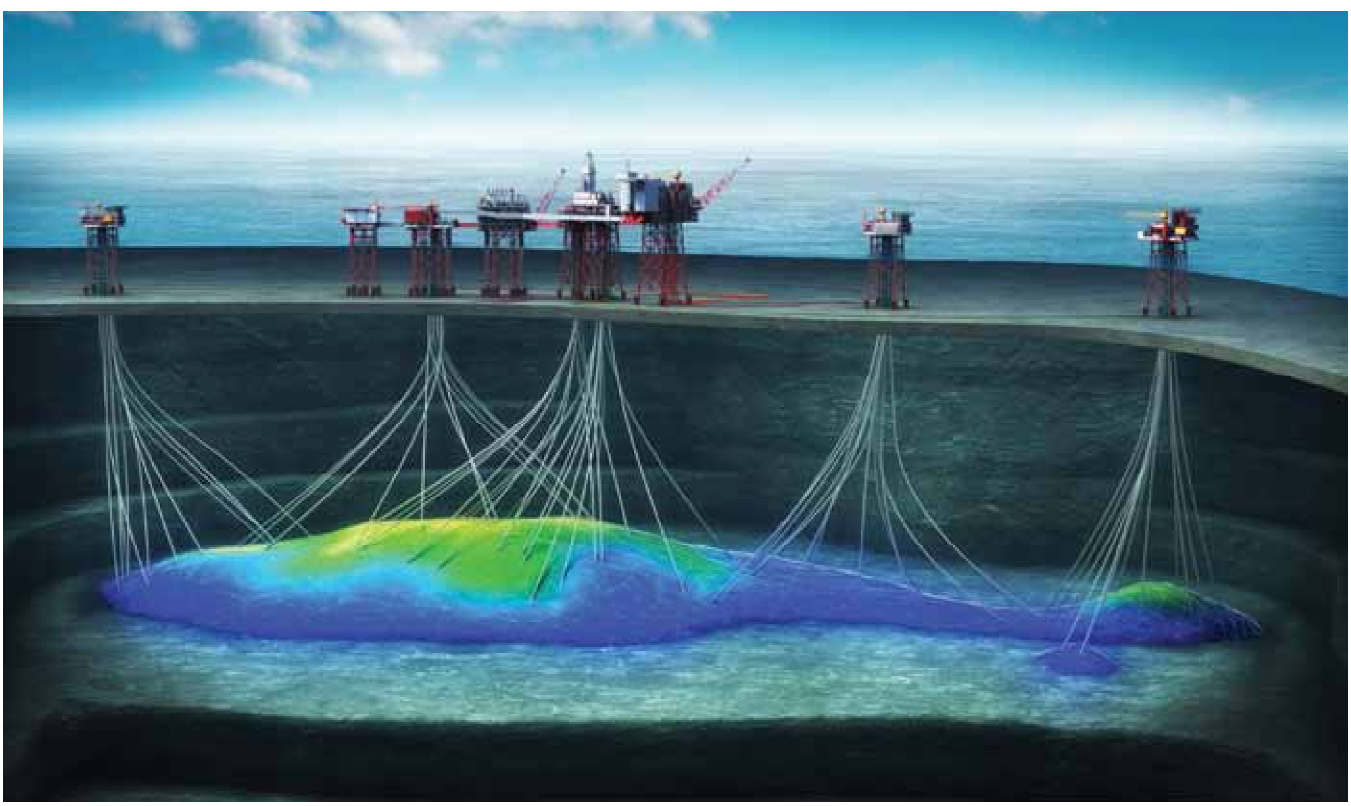
### Renewing the regulation

The challenges are not just technical. The technical challenges – and new solutions – create regulatory challenges and means standards need rewriting, both of which can be lengthy processes.

Norway’s Norsok D-010, which focuses on well integrity, was last revised in 2013. The first hearing to update it was in 2017, a draft is due to be published early in the new year, with the final revision in place sometime in 2019. Revisions of other NORSOK standards, including D-002 on well intervention equipment, and D-007 on well testing, are expected to kick off in early 2019.

Norway’s Petroleum Safety Authority (PSA) has greater worries. Specifically, around unconventional well barriers, such as some of those mentioned above. Johnny Gundersen, principal engineer the PSA, said, “It looks like the industry’s main focus is reducing cost and time. We don’t mind that, but, it’s important to have robust barriers that won’t leak now or in the future.” But, he said, existing barrier verification methods are unfit for the unconventional or new barriers being developed. These still need to be tested and proving the new subsurface theories will be really challenging, he said.

“The question is, are we taking more risk than we used to? What’s the way forward? It’s challenging for companies but also for the regulator. The promise is robust barriers and no leaking wells. Verification and documentation of the well barriers are established requirements.” Higher focus needs to be given to this earlier, he said, and more subsurface data needs to be collected.



Source: Aker BP

**Aker BP is still drilling on the Valhall field,** but recently completed a successful P&A campaign.

# HUNTING HYDROCARBONS

*A new tool is being added to the box for hydrocarbon hunting – and a raft of other anthropomorphic and chemical signatures in the world's seas and oceans.* Offshore Engineer *reports on developing unmanned wide area remote ocean sensing systems for seep, sound and leak detection.*

**BY ELAINE MASLIN**

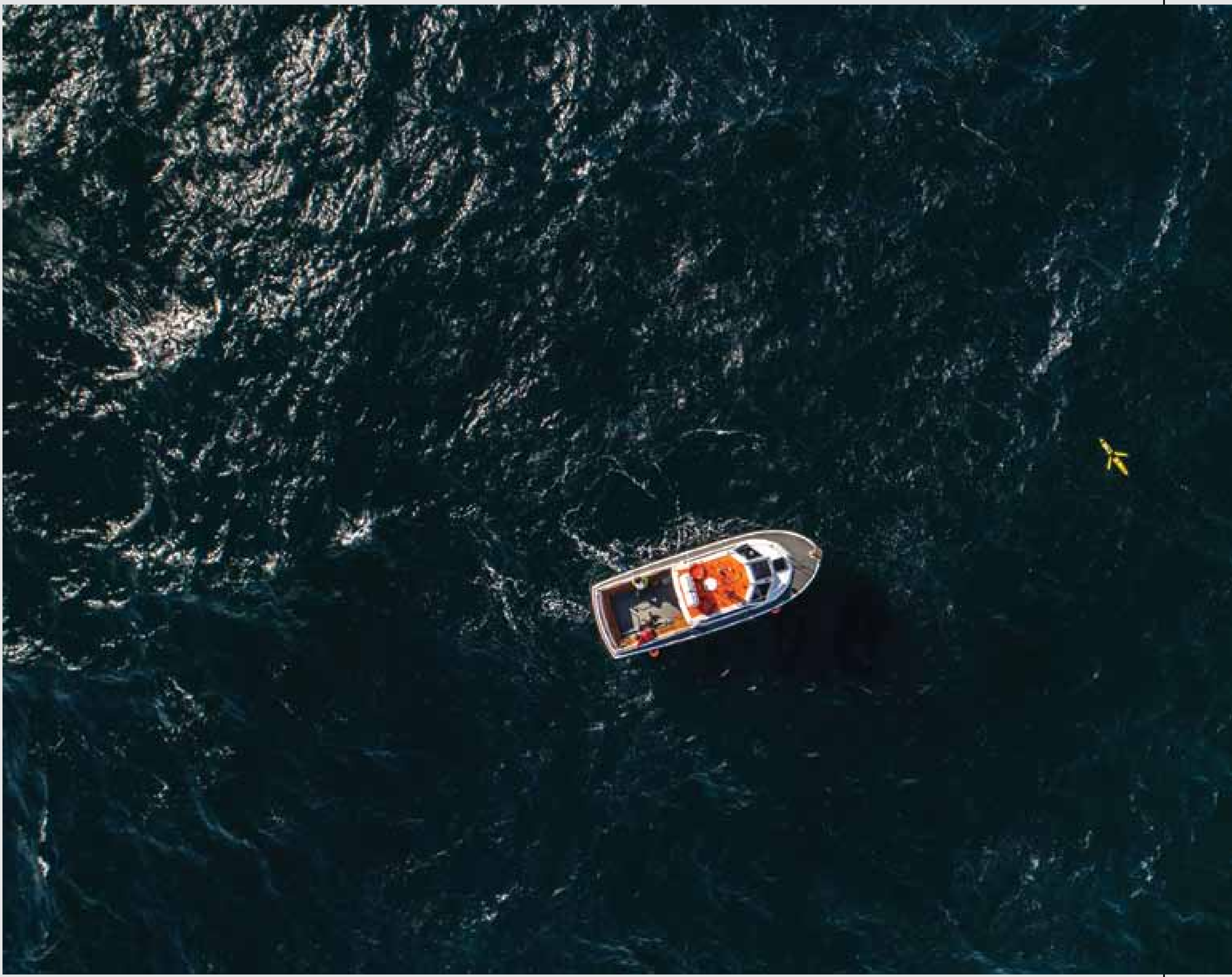
Since their emergence in the 2000s, ocean glider systems have opened up new possibilities for ocean observation and monitoring. Their capabilities are continuing to expand, including in the oil and gas exploration and production arena, from hydrocarbon seep surveys and passive acoustic monitoring (PAM) surveys during seismic operations to leak detection and oil spill monitoring. The primary attraction of ocean gliders is their ability to stay at sea for months, monitoring wide areas in remote locations down to significant depths. This is because their mode of propulsion is energy efficient. There are two main types of glider. A surface glider derives its energy from waves, converting heave into forward motion using blades or fins on a float, beneath the water, connected to the surface system and a subsea glider, converting vertical motion through changes in buoyancy, into horizontal motion using fixed wings, creates a "saw-tooth" shaped trajectory through the water column. To communicate collected data, satellite or radio communication are usually used, which allows the glider to transmit data, receive mission updates and correct the gliders trajectory.


**One of Blue Ocean Monitoring's Slocum Gliders fitted with a hydrophone.**

Source: Blue Ocean Monitoring

**Sensing with Slocums**

Australia-based Blue Ocean Monitoring has been building its track record in the use of subsea gliders, including Teledyne Webb Research's Slocum



Gliders. The company has been expanding both the range of missions possible with these vehicles, to tasks such as drill plume and produced formation water monitoring and oil spill response activities, providing operational insights into how these should be undertaken. The company's latest goal is to deploy multiple gliders at once with navigation and control from an unmanned surface vessel (USV). But more on that later.

Slocum Gliders weigh 50-60kg, operate for up to 12 months, payload dependent, and are light enough to be deployed over the side of a vessel by one or two people. The Slocum G3 Glider can operate down to 1,000m and travel up to 13,000km, depending on the batteries used, traveling at up to 2kt. Positional accuracy while submerged can be supported using a Doppler velocity log (DVL), pressure sensor, altimeter and magnetometers.

In 2016, working with Canada-based JASCO Applied Sciences, Blue Ocean deployed a Slocum Glider for PAM operations, to aid environmental and anthropogenic monitoring during 3D seismic surveys North Western Australia. A glider, fitted with JASCO wideband hydrophones, was used to record low and high frequency acoustic signals from marine life in the survey area. The glider traversed for four days, covering about 30km/day, depending on the current, before performing simultaneous operations with the seismic vessel, in a pre-designated PAM area, for a further nine days said Ramsay Lind, General Manager – EMEA, at Blue Ocean. The glider, operating in about 200m water depth off Exmouth, carried a CTD (conductivity, temperature and pressure, i.e. depth) sensor and the hydrophone, which picked up the sounds of the seismic shots used to validate acoustic propagation models for environmental impacts and understand the efficacy of

A PAM enabled glider platform deployed from small surface vessel.

INSET BELOW A Blue Ocean Monitoring-owned Slocum glider from Teledyne Webb Research being deployed for ocean monitoring.

Source: Blue Ocean Monitoring

glider platforms being used in this particular application. Local marine life was also of interest with the glider detecting dolphins and an Omura whale.

**Hydrocarbon hunting**

The same year, Blue Ocean also carried out a multiclient speculative geochemical survey, which involved gathering evidence of subsea hydrocarbon seeps, offshore Papua New Guinea. For this project, Blue Ocean deployed a glider equipped with two fluorometers (Wetlabs SeaOWL and Turner C3).

Then, in 2017, Blue Ocean ran another geochemical survey, this time with a more comprehensive set of sensors – and a focus on expanding communications and control capabilities. The Yampi Geochemical Glider Survey, a self-funded research and development project in the Browse Basin, off Australia's northwest coast, was also designed to detect gas seeps, but, this survey incorporated the use of methane sensing technology, which has previously been used on autonomous underwater vehicles (AUV), but not on underwater gliders. By incorporating a Franatech laser methane sensor, the survey was able to provide greater detail about the hydrocarbons detected, Lind said, "high-grading the information gathered, through the accurate detection of methane in the first instance before contrasting peak values of methane with fluorescent dissolved organic matter (FDOM) values from the fluorometer."

The project also introduced near real-time communication systems and adaptive management of the glider, by programming the glider to surface at a set interval and then communicating with it using satellite communications. This meant shore-based glider pilots, in Australia or the U.S. (depending on the time of day), could guide the glider to investigate any anomalies that had been spotted in data they had received from it in greater detail. This data could then be used to inform the survey plan.

The project focused on a well-known seep, in 200m water depth, near the Cornea oil and gas field and ran for 14 days. The results were positive, showing background dissolved methane concentrations of 3-4 volumes per million (vpm) as well as distinct plumes measuring 30 to 84vpm. The highest concentration plume was detected at 160vpm, which concurred with existing Geoscience Australia data. This was peer reviewed by the CSIRO.

"We were very pleased with the results, the area proved a good testing ground for the glider showing good alignment with current understanding from Geoscience Australia, demonstrating that the glider platform, with its multiple payload capability and high spatial and temporal resolution, can have real added value, when high grading areas of interest for geochemical seep detection."

"We're also looking at using multiple hydrophones to gain directionality alongside real-time PAM processing capabilities," he added. In other words, by using multiple systems, they can not only detect signals in the water, but also say with a higher degree of precision where they are coming from.

Blue Ocean is already deploying multiple hydrophones on single gliders, enabling some directionality of the sound signal to be determined. It is thought that using multiple gliders fitted with hydrophones, tracked with ultra-short baseline (USBL) communication systems would provide wider area coverage and greater accuracy for calculating where a sound is coming from. Blue Ocean is planning to trial this concept this year.

**Introducing onboard processing**

Blue Ocean is also working on integrating JASCO's OceanObserver system into its gliders. This would enable some real-time data processing on board the glider. "As it stands, some 375,000 samples per second can be recorded on a glider during a PAM survey," Lind said, "which is a lot of number crunching (and a lot of data that would need to be transmitted). With this software, some of the processing can be carried out on board the glider, enabling real-time detection of marine mammals for instance."

Blue Ocean is also looking to where it can provide its capabilities in the offshore wind industry, specifically around construction operations. It's looking at taking take part in a pilot project to study the impact of piling operations on marine life using a remote, dynamic platform. "The oceans are a vast and largely underexplored space, but with these technologies we're able to learn much more, without the large overheads, associated with traditional survey techniques," Lind said.

# *After Heavy Spending on Developing LNG Export Capacity*

## Oceania Companies Focus on Expansion and Backfill

**BY NICOLE ZHOU,** APAC Analyst, GlobalData

Australia is well positioned to maintain its role as an important supplier of the world's energy needs, particularly in the Asia-Pacific region. In 2017, Australia exported around 7 billion cubic feet per day (bcfd) of gas, equal to around 60% of production, with 46% of these exports going to Japan and 31% to China. Natural gas was the third biggest source of energy production in Australia in 2016-17, accounting for 23.1% of the total, behind coal and renewables. This was followed by oil and natural gas liquids (NGL) (3.3%) and liquefied petroleum gas (LPG) (0.5%), according to the Department of Environment and Energy (2018) Australian Energy Statistics.

In 2018, natural gas represented 84% of Oceania's hydrocarbon production in barrel of oil equivalent (boe) terms. Most of this production is from Australia, which is forecast to provide about 85% of the region's natural gas production from 2019 to 2025. Australia's liquefied natural gas (LNG) export capacity is forecast to be equivalent to 80% of the production in 2019 (Figure 1). Offshore production provides nearly two-thirds of the natural gas supply in Australia. While significantly smaller, Papua New Guinea's output is expected to double over the period. Most of the gas production in Papua New Guinea is exported. Gas production is forecast to increase in line with LNG export capacity expansion, although companies will be required to reserve around 10% of gas production for domestic use.

### KEY UPCOMING AUSTRALIAN UPSTREAM PROJECTS

After completing a series of newbuild LNG export projects over the past five years, Australia has the largest LNG export capacity in the world. Australian operators are now turning their attention to developing assets to backfill the existing projects instead of investing capital expenditure (capex) in new LNG liquefaction capacity.

Three key offshore projects are the

**Figure 1: Oceania Natural Gas Production and LNG export capacity Forecast from 2019 to 2025**


Source: GlobalData Oil & Gas Intelligence Center

**Table 1: Key Announced Offshore Australia Projects**

| Field | 2C Resources (tcf) | Production Target (mmcfd) | FID | Production Start Year | Operator | Upstream Development Capex (US$ mil) | LNG plant |
|---|---|---|---|---|---|---|---|
| Caldita/Barossa | 3.44 | 470 | 2019 | 2023 | ConocoPhillips | 1,400 | Darwin |
| Scarborough | 7.3 | 1,000 | 2020 | 2023 | Woodside | 6,300 | Pluto |
| Browse | 15.4 | 1,270 | 2021 | 2026 | Woodside | 22,000 | NWS |

Source: GlobalData Oil & Gas Intelligence Center

shallow water gas fields of the Caldita/Barossa asset and the deepwater Scarborough and Browse developments. These developments are yet to be sanctioned, but will be crucial for Australia to maintain supply to the LNG export projects.

The Caldita/Barossa project is around 300km north of Darwin. Development of Caldita/Barossa is expected to utilize a floating, production, storage and offloading (FPSO) vessel with subsea wells, exporting gas to backfill the Darwin LNG plant. The Scarborough gas field is located in the Carnarvon Basin, 375km offshore Western Australia at around 900 meters water depth. Development of Scarborough includes a semi-submersible platform, with subsea wells, exporting gas to support an expansion of the Pluto LNG facilities.

The largest project under discussion is Browse, which aims to bring online the Brecknock, Calliance and Torosa fields offshore West Australia. The project has been stalled for a few years, with greenfield onshore and floating LNG proposed and ruled out, and it is now expected to follow a similar pattern to the other projects, utilizing two FPSOs, with subsea wells and backfilling the existing North West Shelf (NWS) LNG trains.

Liquids production in Australia has fallen from 29% of production to 16% on a boe basis, due to the focus on natural gas for LNG export and the lack of oil discoveries.

The shallow water Dorado oil discovery last year by Quadrant Energy (now acquired by Santos) and Carnarvon Petroleum is a significant boost for the region.

The discovery is reported to hold 2C resources of 186 million barrels of liquids and 552 bcf of gas. This is relatively small on global scale, but is the largest liquids discovery for over 30 years in the North West Shelf area. It could spur further exploration and liquids focused developments nearby.

# ASIA PACIFIC 2019

## *Expect a 'Relatively Low-key Year'*

**BY ERIC HAUN,** Managing Editor

The Asia-Pacific offshore oil and gas industry has begun to emerge from the recent global downturn, but remains among the regions where the road to recovery has been particularly slow.

"Australia has seen positive news on new liquefied natural gas (LNG) start-ups and a surge in merger and acquisition activity, but elsewhere optimism has been confined to a few pockets of exploration success in Myanmar, Indonesia and China," said Andrew Harwood, Wood Mackenzie's Research Director, Asia Pacific Upstream Oil & Gas. "Looking forward, a lack of sustained exploration activity and success has left the hopper of new development projects looking empty."

The prolonged depressed oil price has had a particularly harsh effect on exploration throughout the region. "Exploration and appraisal wells in 2018 are at around half the levels of 2014," Harwood said. "Similarly, the amount of new acreage awarded has also fallen to less than half the levels we saw in 2014."

Production, too, has been on the decline through much of Asia-Pacific, especially in Indonesia, where Harwood expects to see the largest fall in oil production as legacy producing areas become increasingly mature. According to the International Energy Agency, shal-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low water oil production offshore Indonesia – as well as off of China, India and Malaysia – is projected to experience declining production to 2040.

Several regional factors have had a dampening effect on local offshore recovery. Harwood said Asia-Pacific's offshore industry faces obstacles such as "challenging fiscal terms compared with other global jurisdictions, regulatory uncertainty and a changing corporate landscape wherein the traditional international exploration and production companies are facing stronger competition from national and regionally-focused operators."

Local policy, too, will continue to play an important role on the road ahead. "2019 will see general elections in Thailand, Indonesia, the Philippines and India, and potential government change in Australia. As domestic energy demand increases in the region, energy policies are often at the center of the political debate, with resource nationalism often used to gain public support," Hardwood explained. "However, deterring international investment could have longer-term implications for energy security across the region and place financial and technical risk solely in the hands of the region's national oil companies."

"While we do expect some recovery in 2019/2020, we expect only a marginal improvement," Hardwood said. "Activity is unlikely to reach the levels we saw in 2014 anytime soon."

Harwood expects 2019 to be a "relatively low-key year" for new project sanctions in Asia-Pacific. He said the two largest projects targeting final investment decision (FID) over the next 12 months – PetroVietnam's Block B gas development and ConocoPhillips's Barossa – could both be pushed back into 2020.

**Glimmers of hope**

Still, there is reason for optimism. "There are signs that Asia-Pacific explorers are looking to drill further afield again in 2019, with several wells planned that could open new plays or discover material resources," Harwood said.

"In Papua New Guinea, Total's Mailu-1 well is targeting a giant oil prospect in over 2,000 meters of water, potentially opening a new ultra-deep offshore play in the Papuan Basin," Harwood added.

"Repsol's Rencong-1X well, offshore North Sumatra, Indonesia, is generating strong interest from potential farm-in partners," he said. "Expect a deal to be done before the well spuds in Q3 2019."

From a licensing perspective, several countries are set to launch new bid rounds; Bangladesh, India, Indonesia, Myanmar and the Philippines are among those offering new acreage in 2019. "We'll be closely watching how successful these license rounds are to determine whether Asia-Pacific can continue to attract material exploration investment," Harwood said.

The analyst expects Australia and China will see the largest increases in gas production on the back of the former's LNG investment boom that started almost a decade ago – and is coming to its dramatic end with Shell's Prelude FLNG mega project due to produce its first cargo in early 2019 (read more on page 32) – as well as the latter's push to dump coal for gas.

Elsewhere, the SK408 block in Malaysia is set to produce its first gas before the end of the year. Harwood said this will be a key project for operator Sapura Energy, which recently agreed a joint venture with Austrian national oil company OMV.

# AOG 2019

## *Innovations in O&G Asset Integrity*

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While the term 'innovation' may have some running for the hills, a group of nondestructive testing (NDT) and asset management experts who will be speaking and exhibiting at the 2019 Australasian Oil & Gas Conference & Exhibition (AOG) are reaping the benefits of it as Australia's liquefied natural gas (LNG) industry transitions from a construction to a maintenance cycle.

What:
**Australasian Oil & Gas Exhibition & Conference**

When:
**March 13-15, 2019**

Where:
**Perth Convention and Exhibition Center**

Exhibiting Brands:
**250**

Visitors:
**8,000**

For more information:
**aogexpo.com.au**


Source: AOG

**Robotics**

In many instances, inspection work on process vessels and tanks on offshore oil and gas rigs have required shutting down the platform to facilitate manual inspection – a process that is often time-consuming, unproductive, costly and of course, extremely hazardous.

"We've seen the market shift into a maintenance cycle, and over the last four years, companies have come to accept that remote visual inspection as a technology is the way forward.

And with that has come robotics. "Innovative robotics technology and remote inspection systems can deliver far safer, more cost-effective, more reliable and more feasible solutions," said Jason De Silveira, Managing Director of remote visual inspection (RVI) and NDT solutions provider, Nexxis, who will be exhibiting at AOG March 13-15 at the Perth Convention and Exhibition Center. The numbers back up De Silveira's claim, with the oil and gas industry planning to increase investment in drones and robotics by 13% in the next four years, as per analysis by Frost & Sullivan.

While Peter Milligan, CEO of the Australian Institute for Non-Destructive Testing (AINDT), agrees that the acceptance of robotics in oil and gas applications is growing he sees them as a tool and not a total solution.

"Robotics has a place; however, I firmly believe that the role of an NDT technician needs to remain in the hands of an appropriately certified person whom can make a judgement call based on skill and experience," Milligan said.

**Conected devices and big data**

Milligan said another trend in NDT is the growing use of remote monitoring systems which allow assets to be monitored 24/7, and if issues are detected a technician can be deployed to the exact location for further investigation.

"Before repairs can be made, maintenance teams first need to know what they need to repair.

"Remote monitoring locates, identifies, monitors and sanctions defects within the assets being inspected which then allows maintenance teams to fix issues if required to avoid lengthy shutdowns if an asset fails," said the Chief Executive of AINDT.

With technologies such as sensors becoming more affordable and robust, and with these sensors attached to standard equipment, overall asset health can be monitored more efficiently a practice often referred to as condition monitoring.

But for Alan Russell, Ausgroup Limited's General Manager of Group Strategy and Growth, the key to effective condition monitoring is not strictly limited to data collection.

"The challenge is understanding the

**Continued on page 63**

TELEDYNE ENERGY SYSTEMS INC.

# Untethered Subsea Power

BY ERIC HAUN

U.S. based tech conglomerate Teledyne has long supplied fuel cell technologies for NASA and other customers for space and terrestrial applications. Now its Teledyne Energy Systems, Inc. (TESI) arm is looking to take the technology to new depths as a source of untethered power for applications below the ocean's surface.

"In everything that we've seen from doing our market study and research, there is a gap in providing untethered power for various [subsea] applications," according to Mitch Icard, TESI's Vice President and General Manager, who said TESI's Subsea Power Node has been engineered to provide persistent power for underwater vehicles and subsea oilfields.

Icard said the initial plan was to use fuel cells to power underwater vehicles directly, but "we determined that there is too many configurations and it probably be a tough price point". He explained, "Given that most of the vehicles are powered by lithium ion batteries, we felt that it would be a much better solution to put energy subsea and recharge those assets on location."

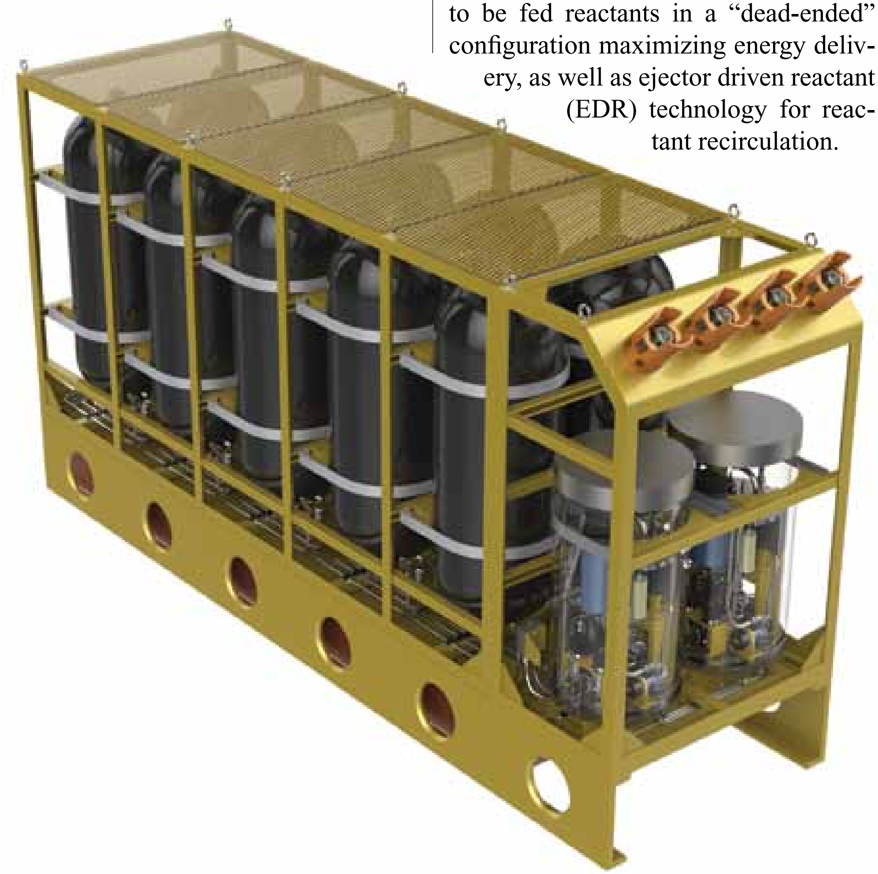
The Subsea Power Node uses Teledyne's proton exchange membrane (PEM) fuel cell technology, which provides more than 10,000 hours of life, according to the developer. The stack design is specifically tailored for operation with pure oxygen. The fuel cell system features an integrated balance-of-plant (BoP), which allows the fuel cell stack to be fed reactants in a "dead-ended" configuration maximizing energy delivery, as well as ejector driven reactant (EDR) technology for reactant recirculation.

The fuel cell system is reactant storage agnostic, meaning reactants can be supplied via compressed, cryogenic, or solid-state reactant storage systems. The Subsea Power Node is equipped with a compressed-gas reactant storage system that is commercially refillable.

"The engine, or fuel cell, was something that we had developed for space flight to go in the upper stage for the space launch system," Icard said. "We had converted that technology to operate in a similar environment from deep space to deep water."

"Everything except the fuel cell engine is all commercial off-the-shelf parts," Icard said, noting that the steel head tanks, electronics package, Teledyne ODI wet mate connectors, Teledyne Benthos modem are all commercially available. "All of these things have had sea trials. What we're providing is a systems integration package that we think solves a really pressing problem."

A 100Kwh system (8kW continuous power) expected to launch in 2019 is 4 x 4 x 5 feet and weighs in at approximately 840 kilograms, while a 600kwh (16kW continuous power), 3,000 kg version is in development to offer greater capabilities. TESI expects to scale up the system to 20Kwh by 2021.



Source: TESI

**Teledyne Energy Systems, Inc.'s** subsea power node; 600 kWh unit above left, 100 kWh unit above right.

OCEAN POWER TECHNOLOGIES

# PowerBuoy

Ocean Power Technologies is developing new tech to complement its existing wave-powered PB3 Power-Buoy. A new hybrid, liquid-fueled PowerBuoy and subsea batteries are due to launch in 2019.

The quickly deployable hybrid surface buoy with energy storage will be capable of providing power in remote offshore locations and is primarily intended for shorter term deployment applications such as powering electric remotely operated vehicle (ROV) or autonomous underwater vehicle (AUV) inspections and short-term maintenance, topside surveillance and communications, and subsea equipment power purposes.

The lithium ion subsea batteries currently under development create seafloor energy storage and can be linked to the buoy or deployed independently, to supply power for subsea equipment, sensors, communications and AUV or ROV recharging.

Source: OPT

**OPT's hybrid PowerBuoy** with seafloor battery.

H. HENRIKSEN

# Arctic Oil Spill Cleanup Device

A winterized version of Norwegian developer H. Henriksen's FoxTail vertical adhesion band (VAB) skimmer is able to filter large quantities of oil from seawater using sorbent mops – even in arctic conditions.

The standard FoxTail is able to operate in 21 degrees Fahrenheit, but the developer said colder weather posed a problem for the skimmers when ice – mainly from sea-spray – started to grow on the machines. With the help of a hydraulic heating system, integrated transfer pump and insulated cover, the new Arctic Foxtail can operate down to -6 degrees Fahrenheit, under the same sea temperature and wind conditions.

H. Henriksen said the Arctic FoxTail proved capable of stable and continuous operation in sub-zero arctic conditions during recent testing on board the offshore supply vessel MS Polarsyssel in Norway's northern Svalbard archipelago.

Source: H. Henriksen

**The Arctic FoxTail** is a cold weather ready version of H. Henriksen's existing FoxTail mop skimmer.

KONGSBERG MARITIME

## Hugin Superior AUV

Kongsberg Maritime's new flagship autonomous underwater vehicle (AUV), Hugin Superior, promises significantly enhanced data, positioning and endurance capabilities without changing size or form factor.

Built upon the existing Hugin platform, the 6,000-meter-rated system carries the new HISAS 1032 dual receiver generating synthetic aperture sonar imagery and bathymetry across a 1,000-meter swathe. It's also equipped with the EM 2040 multibeam echosounder, wide aperture color UHD camera and laser profiler, sub-bottom profiler, magnometer and diverse environmental sensors.

Superior offers 30% more energy for extended endurance or added sensors. Updated onboard data processing, a faster network and extra in situ navigation performance make terrain navigation and autonomous pipeline tracking standard capabilities.


Source: Kongsberg Maritime

ENSCO

# Continuous Tripping Technology

Offshore drilling services provider Ensco has rolled out a new proprietary solution engineered to provide greater pipe tripping safety and efficiency.

When used in concert with other key equipment, sensors and process controls, Ensco's new patented Continuous Tripping Technology (CTT) can fully automate the movement of the drill string into or out of the well at a constant controlled speed, the company said.

The system, which Ensco said can be retrofitted to both floaters and jackups, and is particularly well-suited for ultra-deepwater drillships and larger modern jackups, uses automation to eliminate human error and personnel exposure associated with the conventional stand-by-stand method.

Ensco claims CTT enables pipe-accelerated tripping speeds of up to 9,000 feet per hour when deployed during offshore activities. The constant tripping speed minimizes surge and swab pressure on the wellbore by eliminating intermittent stopping and starting as well as excessive peak speeds.

Ensco said it recently installed and is commissioning the CTT system on the 2016-built Ultra-Enhanced, Super A Class jack-up ENSCO 123. The rig is expected for delivery in March 2019, following system commissioning and rig acceptance trials.

**Continuous Tripping Technology** installed on the jack-up ENSCO 123. (Source: Ensco)

**BAKER HUGHES, a GE Company**

# Subsea Connect

**BY JENNIFER PALLANICH**

New lightweight, modular subsea technologies could reduce not just lead times for equipment delivery but lower the total cost of ownership for the full life of the field. The Subsea Connect system from Baker Hughes, a GE company, is centered around Project Connect, reservoir to topside technology solutions, flexible partnerships and commercial models and digital enablement, which together can reduce the economic development cost of subsea projects by an average of 30%, BHGE believes.

Neil Saunders, president & CEO of BHGE's Oilfield Equipment business, said the price reduction could make marginal assets attractive to develop and improve economics for those that already meet breakeven requirements.

The industry downturn saw many subsea vendors bring prices for technology and equipment down by about 30%, thereby driving down the breakeven price for projects. "But that 30% is not enough. We needed to do more," Saunders said.

BHGE's answer lay in removing costs at an opex level over the life of the field, rather than purely during the capex portion of a project, Saunders said. The result was Subsea Connect, which he said BHGE believes will make a "long-lasting, sustainable change and driving value from concept to commissioning and over the full life of field."

A major component of that is the new Aptara TOTEX-lite subsea system, which includes the lightweight compact tree, modular compact manifold, composite flexible risers, SFX wellhead solution, modular compact pump and subsea connection systems. They are modular, structured, compact and designed to be more responsive to changing conditions across the life of field.

For example, with the modular Aptara system, first a high-integrity pressure protection system (HIPPS) tree cap can be placed on the wellhead, and it can be removed and replaced with the production tree cap, then the boosting tree cap as the well's production stream changes.

The Aptara subsea system can contribute up to 50% cost saving over the total cost of ownership, Saunders said.

Aptara fits under the reservoir to topsides technology solutions pillar, which draws on BHGE's fullstream capability to offer reservoir management, field development, well construction, topside optimization and subsea engineering. With Project Connect, BHGE helps customers target specific project outcomes and increase speed to financial investment decision.

The third component – flexible partnerships and commercial models – is designed to leverage relationships with partners to improve project economics.

Digital enablement is aimed at driving uptime and enhancing productivity. BHGE's engageSubsea asset lifecycle management solution, for example, could drive up to a 20% reduction in maintenance costs, and up to a 5% reduction in downtime through predictive analytics.

"We're already delivering against Subsea Connect," Saunders said, noting the company has invested significantly in structuring its subsea production systems portfolio to ensure shorter lead times and quicker responses. "We have also signed an agreement with a major operator to provide the Aptara lightweight compact tree for deployment."

Source: Baker Hughes GE

**Baker Hughes' Aptara TOTEX-lite** subsea system is designed to reduce subsea project development costs.

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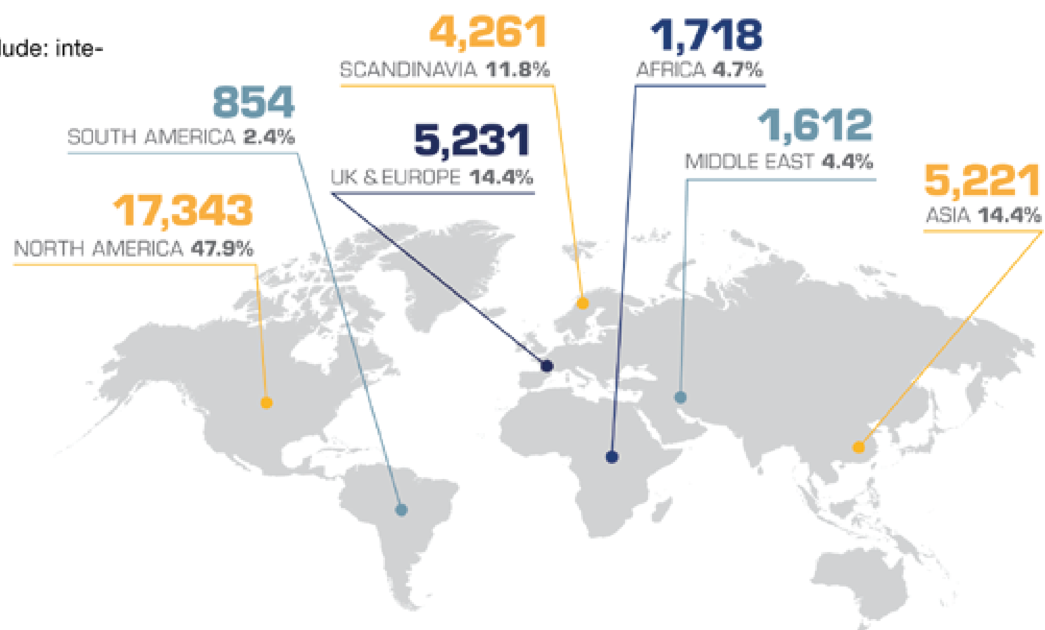


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THE FUTURE OF OFFSHORE ENERGY & TECHNOLOGY.

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Ad Close: Jan 15

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FPSO/FLNG Outlook and Technologies

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Abandonment & Decommissioning

**Subsea**
Subsea Technologies

**Production Operations**
Inspection, Maintenance, Repair

**Drilling and Completions**
Downhole Data: Sensors, Fiber Optic, Wired Pipe

**Regional Report**
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**EVENTS & BONUS DISTRIBUTION**

- **Subsea Expo**
  February 5 - 7, 2019
  AECC Aberdeen, Scotland
- **FPSO Europe 2019**
  February 19 - 20, 2019
  London, England
- **Australasian Oil & Gas 2019**
  March 13 - 19, 2019
  Perth, Australia
- **Offshore Mediterranean Conference & Exhibition**
  Mar 27 - 29, 2019
  Ravenna, Italy

## MARCH - APRIL

Ad Close: Apr 8

**FEATURE**

Deepwater: The Big New Horizon

**DEPARTMENTS**

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Transport and Installation: Projects and Vessels

**Subsea**
ROV/AUV

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**Drilling and Completions**
Drilling Automation: From Robots to Big Data

**Regional Report**
Gulf of Mexico & North America

**Special Report**
Japanese Offshore Equipment

**EVENTS & BONUS DISTRIBUTION**

- **Offshore Technology Conference (OTC)**
  May 6 - 9, 2019
  Houston, USA
- **Global Petroleum Show**
  June 11 - 13, 2019
  Calgary, Canada
- **Underwater Technology Conference**
  June 11 - 13, 2019
  Bergen, Norway

## MAY - JUNE

Ad Close: May 22

**FEATURE**

Offshore Renewables Review

**DEPARTMENTS**

**Engineering, Procurement, Installation, Commissioning**
FLNG: Projects & Technologies

**Subsea**
Tiebacks: Projects & Technologies

**Production Operations**
Production Efficiency: Technology & Technique

**Drilling and Completions**
Drilling Technologies

**Regional Report**
West Africa

**Special Report**
Regulation & Classification: Thought Leadership

**EVENTS & BONUS DISTRIBUTION**

- **Brazil Offshore Conference and Exhibition**
  June 25 - 28, 2019
  Rio de Janeiro, Brazil

# 2019 EDITORIAL CALENDAR

Insightful editorial reporting on the technology that drives the global energy industry.

## JULY - AUGUST

Ad Close: Aug 2

**FEATURE**

Subsea Processing

**DEPARTMENTS**

**Engineering, Procurement, Installation, Commissioning**
Advanced Materials & Manufacturing

**Subsea**
Well Intervention

**Production Operations**
Topsides: Design and Equipment

**Drilling and Completions**
Drilling Efficiency

**Regional Report**
Northwest Europe

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Automation: Big Data, Security and Remote Ops

**EVENTS & BONUS DISTRIBUTION**

- **SPE Offshore Europe 2019**
  September 3 - 6, 2019
  Aberdeen, Scotland
- **Offshore Technology Conference Brazil (OTC Brazil 2019)**
  October 29 - 31, 2019
  Rio de Janeiro, Brazil
- **SPE/IATMI Asia Pacific Oil and Gas Conference & Exhibition**
  October 29 - 31, 2019
  Bali, Indonesia
- **ATCE 2019**
  September 30 - October 2, 2019
  Calgary, Canada

## SEPTEMBER - OCTOBER

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**FEATURE**

Big Data and Digitalization

**DEPARTMENTS**

**Engineering, Procurement, Installation, Commissioning**
Brownfield: Projects and Life Extension Technology

**Subsea**
All Electric Subsea: Power Equipment & Robotics

**Production Operations**
Plugging and Abandonment

**Drilling and Completions**
Rigs: New Design Concepts

**Regional Report**
Brazil

**Special Report**
Automation: Predictive Maintenance

**EVENTS & BONUS DISTRIBUTION**

- **Offshore Energy**
  October 7-9, 2019
  Amsterdam, Netherlands
- **ADIPEC**
  November 12-15, 2019
  Abu Dhabi, UAE

## NOVEMBER - DECEMBER

Ad Close: Dec 2

**FEATURE**

Exploration Outlook

**DEPARTMENTS**

**Engineering, Procurement, Installation, Commissioning**
Marginal Fields: Projects & Technologies

**Subsea**
Pipeline Inspection, Maintenance, Repair

**Production Operations**
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**Drilling and Completions**
Drilling Technologies

**Regional Report**
Arctic: Market and Technologies

**Special Report**
2020 Energy Outlook

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February 5-7
Aberdeen, UK
www.subseaexpo.com

**Underwater Intervention**
February 5-7
New Orleans, USA
www.underwaterintervention.com

**FPSO Europe**
February 19-20
London, UK
https://fpsoeuropecongress.iqpc.sg

**Oceanology International Americas**
February 25-27
San Diego, USA
www.oceanologyinternationalamericas.com

**SPE/IADC International Drilling Conference and Exhibition**
March 5-7
The Haugue, Netherlands
www.spe.org/en/events/drilling-conference/home

**Australasian Oil & Gas Exhibition**
March 13-15
Perth, Australia
https://aogexpo.com.au

**Offshore Mediterranean Conference**
March 27-29
Ravenna, Italy
ww.omc2019.it

**Ocean Business**
April 9-11
Southampton, UK
www.oceanbusiness.com

**Offshore Technology Conference**
May 6-9
Houston, USA
www.otcnet.org/welcome

**Caspian Oil & Gas**
May 29-June 1
Baku, Azerbaijan
caspianoilgas.az

**Data Driven Drilling & Prod. Conf.**
June 11-12
Houston, USA
www.upstreamintel.com/data

**Underwater Technology Conference**
June 11-13
Bergen, Norway
www.utc.no

**Global Petroleum Show**
June 11-13
Calgary, Canada
https://globalpetroleumshow.com

**Brasil Offshore Conference & Expo**
June 28-28
Macae, Brazil
www.brasiloffshore.com/en

**Subsea Well Intervention Symp.**
August 13-15
Galveston, USA
www.spe.org/events

**Offshore Europe Conference & Exhibition**
September 3-6
Aberdeen, UK
www.offshore-europe.co.uk

**Gastech Exhibition and Conference**
September 17-19
Houston, USA
www.gastechevent.com

**Asia Offshore Energy Conference**
September 26-28
Jimbaran, Indonesia
www.asiaoec.com/

**ATCE**
September 30-October 2
Calgary, Canada
www.atce.org/cfp2019

**OilComm and FleetComm**
October 2-3
Houston, USA
www.atce.org/welcome

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# AOG 2019

data. This which has opened the door for data scientists and computers that crunch big data to see patterns and changes in profiles leading to identifying events that have not been seen before. These methods can allow for early-stage predictive interventions."

**Asset Integrity Zone at AOG**

"The market for asset management and integrity technology and solutions has grown exponentially in recent years, and as a result, AOG is placing an increased focus on asset integrity this year to cater for increased visitor interest," said Bill Hare, AOG Event Director.

AOG's Knowledge Forum will feature several specialized technical sessions focusing on asset management, maintenance and testing, to complement the latest technology and service solutions on the exhibition floor in a dedicated Asset Integrity Zone.

"Supported by the AINDT, Asset Management Council and Engineers Australia the Asset Integrity Zone will feature manufacturers and suppliers of nondestructive testing, condition monitoring, diagnostic engineering, or materials and quality testing, corrosion prevention, protective coatings, and asset management products services and technology," Hare said.

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