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Offshore Engineer • March 2017


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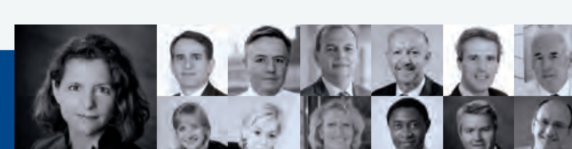
FEATURE FOCUS

Rig Market Review

Features

ON THE COVER

Shedding skin. Since the downturn reared its ugly head, the rig market report numbers show a serious need to continue to cull the herd. Our March cover shows platforms moored off the Cromarty Firth, near Invergordon, Scotland. *Image from iStock.*



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What's Trending

Exxon's Hebron project.
Image from ExxonMobil Canada.

Eyes ahead

- Exxon to startup 5 projects in 2018
- Chariot targets 1 billion bbl off Morocco
- Leviathan first gas set for 2019

Activity

Ichthys facilities named

Inpex held double naming ceremonies at two South Korean yards in mid-February for the Ichthys LNG project's FPSO (*Ichthys Venturer*) and CPF (*Ichthys Explorer*), following the end of construction.

***Ichthys FPSO* naming ceremony.**
Image from Inpex.

People

Oceaneering's McEvoy to step down

Roderick A. Larson

Kevin McEvoy will step down as CEO of Oceaneering International on 5 May 2017. He will be replaced by the firm's current president, Roderick A. Larson. Larson is expected to continue in that role as CEO.

OE OPINION

Undercurrents

Unlocking future success

We might still be wallowing in the mire of one of the most painful downturns the oil and gas industry has suffered, but, there are some who believe that this is an industry to stay.

With a similar spirit to those who led North Sea exploration in the 1970s (minus the flares), the Oil & Gas Technology Centre (OGTC) has been set up with US$224 million government funding (to be matched with cash or in kind by industry) to make Aberdeen a center of oil and gas technology for years to come.

Undaunted by the ongoing pain being suffered by many, with little new investment being made and with modest funds, the center's aims are bold. Goals, which will build on work already done by the likes of the Pilot program and more recent Efficiency Task Force (an Oil & Gas UK initiative) include halving the cost of drilling wells, increasing production efficiency to 80%, reducing asset integrity costs by 50% and solving issues like corrosion under insulation (CUI) monitoring and management, and the high cost and complexity of well plugging and abandonment (P&A). Digital technologies are also within the scope of the OGTC, whose focus is being led by the guidance of the Technology Leadership Board, an industry-regulator body. Initial projects will focus on rigless P&A, improving the speed and performance of drilling wells, including through use of augmented decision making, and asset integrity, says Colette Cohen, a former Centrica exec, and now the OGTC's CEO.

Within asset integrity, the initial focus is CUI and vessel entry. "We want zero vessel entry by 2025," Cohen says. Two sets of field trials focusing on these technologies are due to take place this year, through the OGTC. Another field trial, to test new P&A technology, will also take place, first onshore and then offshore.

The North Sea's so-called small pools – some 210 small fields that are currently uneconomic to develop – will also come under focus. We hope to tell you more about all of the above in the months and years to come.

The center will comprise of a number of thematic "solutions centers" focusing on well construction, small pools, asset integrity, decommissioning and digital. At the center's launch (complete with haggis bon bons) a multi-million pound field life extension and decommissioning research and development center was announced, in partnership between the OGTC, Robert Gordon University and the University of Aberdeen. Other excellence centers, in partnership with academia, will follow. There's also to be a Technology Accelerator, to support smaller companies delivering new technology, and an Innovation Hub, a collaborative space, where the OGTC launch was held early February.

The center's focus is more about the long-term future of Aberdeen, than concern about the current climate. Funding for the center is coming from a $311 million Aberdeen City Region Deal fund and its key backer is Sir Ian Wood, whose seminal *Maximizing Recovery Report* set out actions the ailing North Sea industry needed to take – even before the downturn. Speaking at the launch, Wood said: "The truth is, we haven't developed new technology for a number of years." He said, at $100/bbl, it was too easy; the industry was doing what it had done in the past. The industry is also conservative, he says. "There is a frustration in the supply chain that's keen to differentiate itself, but, in many cases, is unable to get new technology deployed." If new technology isn't developed, the industry will struggle to unlock the 10-20 billion boe remaining in the basin, he said. Many suppliers will say they have new technology but it is hard to get in the door at operators. "[The OGTC] will only succeed with operators, the supply chain and others involved," Wood said.

Another gripe is the lack of R&D funding for industry in the UK. It's hoped the OGTC might help change that, too. OE

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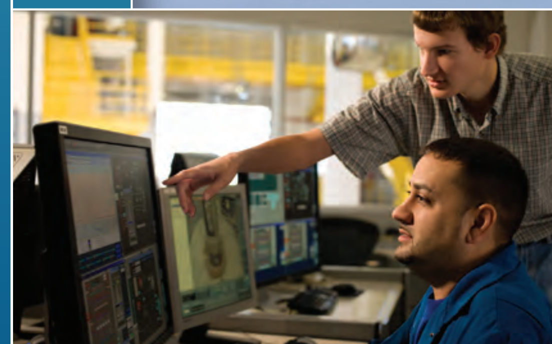


The AquaWatcher sensor can be deployed stand alone or installed anywhere in the subsea production system.

Global E&P Briefs

A BHP joins BP in sanctioning Mad Dog 2

BHP Billiton approved US$2.2 billion for its share of the BP-operated Mad Dog Phase 2 project. BP sanctioned the project in early December.

Mad Dog Phase 2, in the Green Canyon area in the deepwater Gulf of Mexico, is an extension of the existing field. The project includes a new floating production facility capable of producing up to 140,000 bo/d from up to 14 production wells. Startup is expected in 2022. BP has a 60.5% interest in Mad Dog, with partners BHP Billiton (23.9%) and Chevron subdiary Unocal (15.6%).

B TGS starts Otos survey

TGS started the Otos multibeam survey and the first stage of a seep and geochemistry program in the US Gulf of Mexico (GoM). The study hopes to provide new insight into the distribution of different source rock geology throughout the US GoM, including linking to the recent Gigante survey in Mexico.

The program will cover about 289,000sq km and includes 250 cores with advanced geochemistry analysis. Final results should be available in late 2017. TGS will be working with Fugro and TDI Brooks.

C Tullow eyes Suriname probe

Independent explorer Tullow Oil is targeting the 500 MMbo Araku prospect offshore Suriname in 2H this year. The Araku prospect, in Block 54, has been described as high impact. Tullow, operator on Block 54, with partners Statoil and Noble Energy, says it is a large structural trap and has been significantly de-risked by a 4000sq km 3D seismic survey carried out in 2015. *For more news on Suriname, see page 56 of this month's issue.*

D Spectrum extends Potiguar study

Spectrum, in partnership with BGP, started a 6000km multi-client 2D survey offshore Brazil in the Potiguar Basin, an extension of the Potiguar Phase 1 survey.

Data is being acquired with a 10,000m cable with continuous recording to help futher understanding of the basin's architecture. The data will be processed in Spectrum's processing center in Houston.

E BP fires up Thunder Horse expansion

BP started up its Thunder Horse South Expansion project, in the deepwater Gulf of Mexico, in late January, 11 months ahead of schedule.

The project is expected to boost production at the facility by an estimated 50,000 gross boe/d, further boosting output. BP achieved this with the installation of a new subsea production system, 2mi south of the existing Thunder Horse platform (*pictured below*). The system is a collection point for wells connected to the Thunder Horse platform by two 11,000ft flowlines installed on the seabed in late 2016, BP said.


Photo from BP.

The expansion project came in US$150 million under budget (a 15% reduction) by using standardized equipment and technology, rather than relying on customized components, BP said.

F First oil at Stella

First oil has been produced from the Greater Stella Area floating production project using the *FPF-1* semisubmersible production unit in the UK North Sea.

Operator Ithaca Energy said production ramp-up will start when ongoing commissioning of gas processing and compression facilities are completed.

The 45 MMboe development comprises the Stella and Harrier fields, which are being developed as subsea wells tied back to the *FPF-1*.

G Wintershall selects Skarfjell tieback

Germany's Wintershall has submitted plans for its Skarfjell field development offshore Norway. Skarfjell is to be developed via subsea tieback to the nearby Gjøa platform, operated by Engie.

Skarfjell, which is expected to yield between 60-140 MMboe, will include two subsea templates, with lift gas, and water injection for pressure support from Gjøa.

Skarfjell is Wintershall's second operated development project on the Norwegian Continental Shelf – the first was Maria.

H Shell sells off assets

Supermajor Shell has agreed to sell a package of UK North Sea assets to private equity-backed firm Chrysaor for up to US$3.8 billon.

The deal includes Shell's interest in: Buzzard, Beryl, Bressay, Elgin-Franklin, J-Block, the Greater Armada cluster, Everest, Lomond and Erskine, plus a 10% stake in Schiehallion. The deal is expected to close in 2H and includes an initial consideration of $3 billion then up to $600 million between 2018-2021, subject to commodity prices, with potential further payments of up to $180 million for future discoveries.

I Eni starts East Hub

Eni started production at its East Hub Development Project in Block 15/06, offshore Angola, in early February. The Cabaça South East field will produce through the *Armada Olombendo* floating production, storage and offloading vessel, which has 80,000 b/d and 3.4 MMcm/d process capacity.

The development, 350km northwest of Luanda and 130km west of Soyo, consists of five producing wells, four water injecting wells, connected to four manifolds at 450m water depth.

Production from East Hub Project contributed to peak production of 150,000 b/d this year from Block 15/06, which also contains Eni's existing West Hub Project.

J Chariot gains Kenitra acreage

UK independent Chariot Oil & Gas has been awarded a 75% interest and operatorship of the Kenitra offshore exploration permit, in Morocco and, together with the neighboring Mohammedia Offshore Exploration Permits I-III, it could contain more than 1 billion bbl. Chariot will hold the license in partnership with Morocco's Office National des Hydrocarbures et des Mines, which has 25% interest.

K CGG completes Bahrain survey

CGG has completed an airborne gravity gradiometry (AGG) survey offshore Bahrain.

Some 18,000km of high-resolution, low-noise AGG and magnetic data is now available over about 7700sq km of open exploration acreage across Bahrain's offshore licensing blocks.

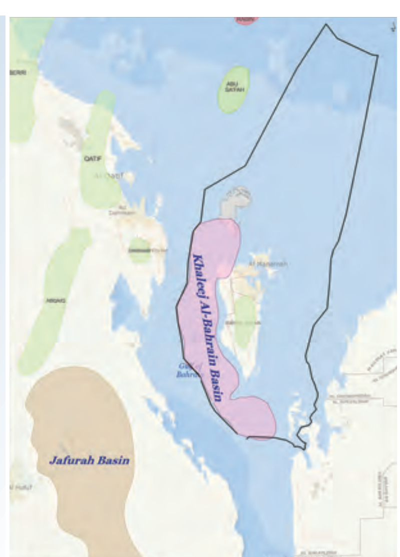


Image from CGG.

L Leviathan first gas 2019

Noble Energy is targeting first gas on the giant Leviathan project offshore Israel for the end of 2019.

The estimated 22 Tcf gas field, 130km offshore, in 1600m water depth, will be developed in phases. Stage 1A will have a 12 Bcm/yr (1.2 Bcf/d) capacity and will cost US$3.5-4 billion, said Noble.

The development will be a subsea system connected to a fixed platform with tie-in onshore in the northern part of Israel.

M India awards offshore licenses

India's government awarded 31 contract areas as part of its Discovered Small Fields bid round 2016, including eight offshore.

Most of the offshore bid awards were in the Mumbai offshore (6), with one each in the Kutch Offshore and KG Offshore. In the Mumbai Offshore, Block B-37 went to Sun Petrochemicals (100%). Block B9 was awarded to Adani Welspun Exploration (100%); B15 to Bharat PetroResources (100%); B127E to Bharat PetroResources (100%); B80 to a consortium of Hindustan Oil Exploration Co. (50%) and Adbhoot Estates Private (50%); Block D18 went to a consortium of EnQuest Drilling (10%) and SKN Haryana City Gas Distribution (90%).

In the Kutch Offshore, Block KD was awarded to Indian Oil Corp. (100%).

In the KG Offshore, Block GSKV1 went to KEI-RSOS Petroleum & Energy (100%).

NEWS

Global E&P Briefs

N Sri Lanka opens Block M2

Sri Lanka's government is offering a tender for Block M2 later this year. Block M2 covers 2924sq km, offshore in the Mannar Basin, and includes the Barracuda and Dorado gas-condensate discoveries.

The remainder of Sri Lankan acreage will be released in a bid round in Q4 2017. WesternGeco is planning 2D and 3D seismic ahead of this off the east coast and in the Mannar Basin. Some airborne FTG/mag surveying is also planned.

O Gazprom Neft picks up Ayashsky license

Gazprom Neft has picked up a 22-year license for the Ayashsky block, in the Sea of Okhotsk, in the western Pacific Ocean, in late January.

The Ayashsky block, next to the Sakhalin-1 and Sakhalin-2 projects, forms part of the Sakhalin-3 project.

Recoverable reserves are estimated at more than 100 million tonne of oil equivalent. Gazpom Neft has acquired 2150sq m of 3D seismic data over the block and is preparing to drill an exploration well at the Ayashsky formation this summer.

P Eni finds gas at Merakes 2

Eni drilled and tested Merakes 2, the first appraisal well of the Merakes discovery under the production sharing contract (PSC) in East Sepinggan, offshore Indonesia, in late January.

The well, drilled to a depth of 2732m in 1269m of water, hit 17m of clean sands with very good petrophysical characteristics of Pliocene age confirming the extension of the Merakes 1 discovery, Eni said.

The Merakes discovery is estimated to have 2 Tcf of gas in place with additional potential to be evaluated.

The block is in the prolific offshore Kutei Basin and the Merakes discovery is 35km from the Eni-operated Jangkrik field, which is expected to start producing through a floating production unit in Q2 this year.

Eni operates the East Sepinggan PSC with 85% interest. It's partner Pertamina Hulu Energi has 15%.

Q 2017 Scarborough FEED possible

Australia's Woodside says the Scarborough project could move into front-end engineering and design in 2017, with a final investment decision by 2020.

Woodside acquired a stake in the ExxonMobil-operated license, containing the Scarborough field, in the Carnarvon Basin, offshore western Australia, late 2016, from BHP Billiton.

Scarborough, Thebe and Jupiter are estimated to contain gross 8.7 Tcf of gas resources. The blocks are close to existing infrastructure, but the project had also been seen as a potential standalone floating liquefied natural gas development.

Contracts

HSM inks platform contract

Dutch fabricator HSM Offshore has won a contract to construct the offshore transformer station for the huge 700 MW Borssele Alpha project offshore the Netherlands. HSM also has an option for the contract to build a transformer station for the 700 MW Borssele Beta project.

The Borssele Alpha transformer station, including jacket and piles, will weigh about 8000-ton and the deck will be about 58-long, 32m-wide and 26m-high.

HSM Offshore will take on the engineering, procurement, construction, transport, installation, connection and testing of the offshore transformer station under an engineering, procurement, construction and installation contract. Iv-Oil & Gas will be responsible for the design, engineering and procurement support. The platform is due to handed over during summer 2019.

JDR to supply ONGC umbilicals

Cameron awarded UK umbilical manufacturer JDR a steel tube umbilical contract, on behalf of ONGC, for 11 wells in Western Offshore project, India.

The 11 wells are either at an infield location or an extension of existing fields and will be connected to nearby host facilities in up to 100m water depth. JDR will manufacture a total 53km of umbilical at its facility in Hartlepool and supply subsea terminations and accessories. Delivery will be in Q4.

Genesis FEEDs MJ field

India's Reliance Industries Ltd. (RIL) awarded Genesis a contract to undertake front-end engineering design (FEED) on the MJ field deepwater development in block KG-DWN-98/3 in the Bay of Bengal.

The project will consider a seven-well gas condensate development via two subsea drill centers, tied back to a floating production, storage and offloading vessel.

TechnipFMC on Israeli FEED

Energean Oil & Gas has appointed TechnipFMC as the concept and front-end engineering design (FEED) contractor for the Karish and Tanin development program, offshore Israel.
Energean is planning to use a floating production, storage and offloading unit on the field. A field development plan is due to be submitted mid-2017.

DOF to provide vessel for Prelude

DOF Subsea will provide the multipurpose support vessel *Geoholm* for Shell's Prelude FLNG project. The *Geoholm* will be required to provide remotely operated vehicle and light construction support services to TechnipFMC in Australia for the Prelude FLNG water intake riser installation.

Technip's previously awarded contract covers multi-disciplinary engineering and design services in support of the Prelude FLNG project, and will allow the smooth delivery of the brownfield engineering scope as the project moves into operations.

Wood Group inks Hess Malaysia gig

Hess selected Wood Group for a five-year operations and maintenance contract off Malaysia.

The contract is to support Hess' newbuild fixed and floating offshore facilities in the North Malay Basin development area about 150km northeast of the Peninsular Malaysia, and includes a one-year extension option. Delivered by Wood Group's Kuala Lumpur office, the contract will support up to 130 new full-time positions in Malaysia. ■

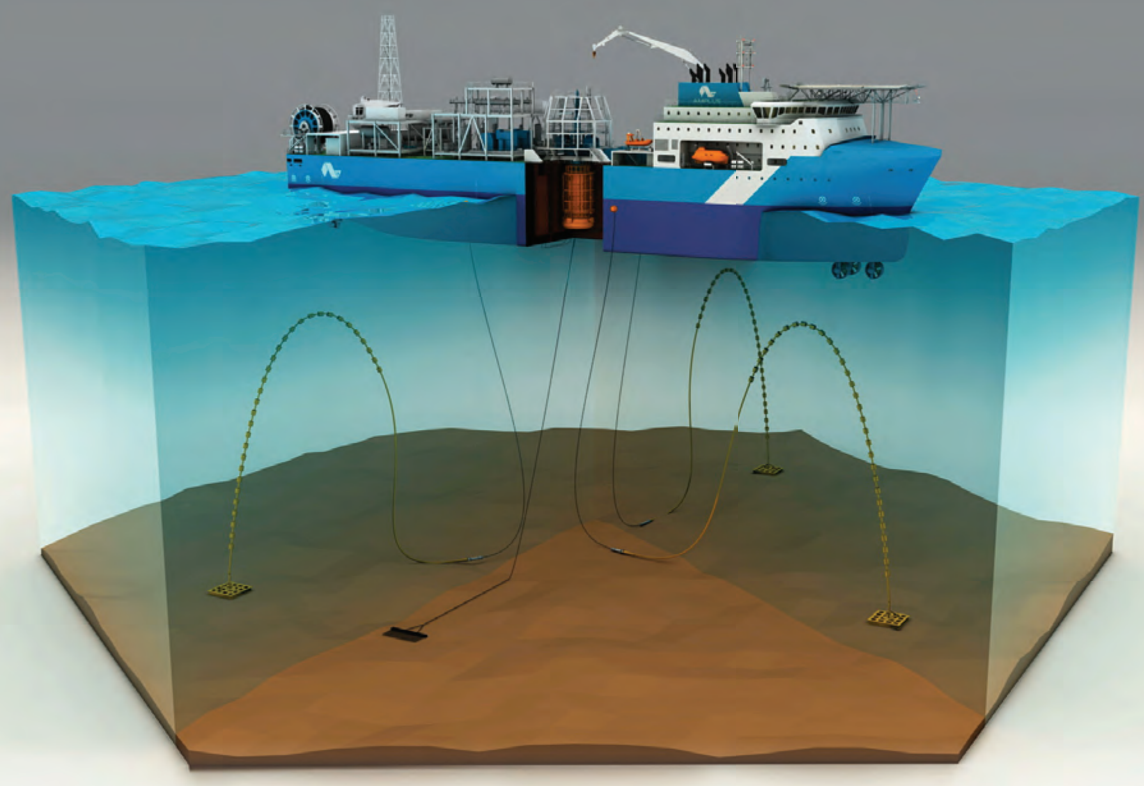

... and his spirit hovered
over the waters

ANALYSIS

In-Depth

Operating in the margins

With more than 3 billion boe up for grabs, the race is on to find ways to unlock the remaining oil and gas in around 350 unsanctioned, and largely marginal, UK Continental Shelf discoveries. Emma Gordon reports on the latest developments.



A DP production system concept for marginal fields.
Image from Amplus Energy.

Developing "really simple" technical solutions that ensure the economic viability of marginal fields, and in particular small pools, is a global oil and gas business opportunity like no other.

That's according to Mike Tholen, UK industry body Oil & Gas UK's upstream policy director. "These are high-risk opportunities in every commercial and technical sense," he says, speaking at the Subsea Expo event in Aberdeen in early February. "Unless we find a way to make them ultra-attractive, they will not move. Whatever the environment we're in."

In fact, he says unless the "all-up costs" – comprising operating, capital, decommissioning and finding spend – are reduced to around US$20/bbl, most small pools will remain economically unviable.

"The challenge to crack is to find $10-15/bbl [operating expenditure] solutions that work. Get those, and you will have business opportunity out there like no other; [one that is] scalable around the world."

Setting the scene earlier at the same session, Carlo Procaccini, head of technology at the UK regulator, the Oil and Gas Authority (OGA), said that there were around 3.4 billion boe reserves recoverable from some 350 unsanctioned discoveries on the UK Continental Shelf (UKCS): 70% of which were small, with reserves of fewer than 10 MMboe.

Carlo Procaccini

Procaccini says that while much was needed to unlock these discoveries, the process had begun, adding: "The complex nature [of marginal fields] requires a collective response. It needs companies to approach it joining forces, working together with the regulator, and with the supply chain in more specific areas of technology and execution."

Taking up this task is Chris Pearson from the recently-opened Oil & Gas Technology Centre in Aberdeen. Pearson is the Solution Center Manager, small pools, a part of the organization tasked with identifying and developing technologies to lower field development costs.

"Alongside the OGA, the National Subsea Research Initiative (NSRI), and others, we're looking at what [technology] makes sense to develop, and in what order," Pearson says.

He adds that adopting and adapting technologies such as production buoys and remote wells would be looked at over the next few years, with enhanced oil recovery techniques and normally unmanned installations earmarked for consideration over the longer term.

Meanwhile, ahead of the 30th offshore licensing round, the OGA will publish data on relinquished discoveries, and their potential within mapped cluster developments.

Eric Marston, the OGA's area manager, Southern North Sea (SNS) and East Irish Sea, says the authority has helped kick-start a development of this kind in the SNS' West Sole Catchment Area: a cluster including one relinquished discovery.

"As an organization, we have a key role in shining a light on the opportunities," Marston says. This includes building the "big picture" of the potential of these clusters, for operators and license holders, using validated industry data, as well as the results of OGA's own development concept valuations.

Ultimately, Marston says this gives companies a better understanding of how these ideas could be progressed, and how a collaborative approach could drive down costs through standardization and rig sharing, for example.

West Sole has 0.5 Tcf recoverable reserves, and four license holders – Centrica, Premier, Dana and Hansa. Marston says that there has been "tangible progress" here in recent months including on confidentiality agreements and infrastructure access. "This is where we've picked up the ball, moved things forward, handed over to industry, they've reciprocated, and are now taking it forward."

Gordon Drummond, NSRI project director, said that this type of clustering and campaigning is likely to work for some discoveries, and would, "see us through 2020-2025." But, "beyond that, the other difficulties, including tight gas, high-pressure, high-temperature and low permeability reservoirs, will have to be solved for us to have a sustainable supply chain and center of oil and gas excellence here in the UK."

Gordon Drummond

That said, Drummond adds that the quickest win will likely be delivered through improved efficiency, citing work carried out by the Oil & Gas UK Efficiency

Quick stats

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

New discoveries announced

Depth range	2014	2015	2016	2017
Shallow (<500m)	76	56	29	1
Deep (500-1500m)	32	20	12	0
Ultradeep (>1500m)	13	12	6	1
Total	121	88	47	2
January 2017	122	89	39	0
date comparison	-1	-1	8	2

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

Reserves in the Golden Triangle

by water depth 2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	14	350	2649
Deep	15	1249	2835
Ultradeep	35	10,783	12,756
United States			
Shallow	9	39	85
Deep	20	1190	1602
Ultradeep	16	2535	2530
West Africa			
Shallow	126	4111	17,554
Deep	32	3360	4550
Ultradeep	13	1761	2518
Total	266	25,028	44,430
(last month)	(262)	(24,873)	(44,080)

Greenfield reserves

2017-21

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	964	36,586.00	358,342.00
(last month)	(967)	37,600.00)	(355,948.00)
Deep	150	7977.00	108,061.00
(last month)	(149)	(7992.00)	(107,871.00)
Ultradeep	76	16,294.00	48,267.00
(last month)	(76)	(16,274.00)	(49,457.00)
Total	1,190	60,857.00	514,670.00

Pipelines

(operational and 2016 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,584.5	(41,715)
Planned/ possible	22,435.76	(22,641)
	64,020	(64,356)
8-16in.		
Operational/ installed	82,547.83	(82,214)
Planned/ possible	47,396.47	(47,977)
	129,944 .00	(130,191)
>16in.		
Operational/ installed	94,967.15	(94,913)
Planned/ possible	43,835.52	(44,494)
	138,803.00	(139,407)

Production systems worldwide

(operational and 2016 onwards)

Floaters		(last month)
Operational	306	(304)
Construction/ Conversion	42	(45)
Planned/possible	292	(293)
	640	(642)
Fixed platforms		
Operational	9107	(9116)
Construction/ Conversion	70	(67)
Planned/possible	1311	(1359)
	10,488	(10,542)
Subsea wells		
Operational	5076	(4992)
Develop	280	(352)
Planned/possible	6390	(6357)
	11,746	(11,701)

Global offshore reserves (mmboe) onstream by water depth

	2015	2016	2017	2018	2019	2020	2021
Shallow	21,272.27	31,782.40	33,260.12	12,484.77	15,941.97	17,366.05	20,667.15
(last month)	(21,262.92)	(32,739.24)	(34,476.01)	(11,652.79)	(16,382.52)	(19,091.67)	(18,710.62)
Deep	972.99	1411.48	5240.33	2799.53	3580.31	5420.49	10,135.39
(last month)	(972.99)	(1459.11)	(5426.11)	(2670.98)	(3422.64)	(5395.94)	(10,025.41)
Ultradeep	2023.19	3075.34	1789.07	3685.74	4362.19	9760.99	5206.35
(last month)	(2342.82)	(2023.19)	(3100.10)	(1767.31)	(3685.74)	(4362.19)	(9972.56)
Total	24,268.45	36,269.22	40,289.52	18,970.04	23,884.47	32,547.53	36,008.89

Source: InfieldRigs 7 Feb 2017

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	96	62	34	64%
Jackup	404	223	181	55%
Semisub	120	61	59	50%
Tenders	28	19	9	67%
Total	648	365	283	56%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	31	25	6	80%
Jackup	25	6	19	24%
Semisub	10	6	4	60%
Tenders	N/A	N/A	N/A	N/A
Total	66	37	29	56%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	3	8	27%
Jackup	119	67	52	56%
Semisub	32	11	21	34%
Tenders	20	13	7	65%
Total	182	94	88	51%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	22	17	5	77%
Jackup	51	26	25	50%
Semisub	24	16	8	66%
Tenders	2	1	1	50%
Total	99	60	39	60%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	50	30	20	60%
Semisub	39	22	17	56%
Tenders	N/A	N/A	N/A	N/A
Total	90	52	38	57%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	2	1	1	50%
Jackup	118	79	39	66%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	124	83	41	66%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	18	12	6	66%
Jackup	18	7	11	38%
Semisub	3	1	2	33%
Tenders	6	5	1	83%
Total	45	25	20	55%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	2	0	2	0%
Semisub	N/A	N/A	N/A	N/A
Tenders	N/A	N/A	N/A	N/A
Total	2	0	2	0%

Source: InfieldRigs 8 Feb 2017

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

Task Force (ETF).

The ETF's Subsea Standardization Project drew on the expertise of around 30 companies, including operators, the supply chain, and industry bodies, to identify efficiencies that could be applied to subsea developments through a simplified, fit for purpose approach.

Steve Duthie, project industry lead, and Technip UK's industry liaison director, says that applying the theory developed through the project realized sustainable savings of around 25% in two initial prospects: Centrica's Pegasus West and Chevron's West Wick.

"Wider adoption... to other prospects, including small pools, will provide sustainable savings going forward."

–Steve Duthie

Efficiencies in the Pegasus West development, a three well gas tieback in the SNS, included introducing a co-mingling manifold to replace the well daisy chain configuration, as well as applying a standard control system design: saving on management and engineering costs.

In Chevron's West Wick, a potential heavy oil tieback to the Captain platform in the Moray Firth, one of the efficiencies was using free hanging risers as an alternative to a caisson riser.

"This [25% cost saving] has demonstrated what can be achieved by adopting a collaborative approach, and highlights the benefits of a simplified and fit for purpose approach to the UKCS," Duthie says. "Wider adoption... to other prospects, including small pools, will provide sustainable savings going forward."

What is clear is that there is no silver bullet to increasing the economic viability of these small, diverse discoveries. But, a coordinated pan-industry effort with the ultimate goal of producing from these marginal discoveries – and in turn extending the life of the UKCS – has begun.

"Hopefully, what comes across is that we are all aligned," Drummond concludes. "We are all looking to get these things over the line, and that single focus is pulling us together." **OE**

FURTHER **READING**

Small pools contain 3 billion boe
Read more about the OGA's report.
http://bit.ly/2I58kOb

Tanked Up [*OE*: August 2016]
Subsea oil storage solutions could help unlock marginal fields. **http://bit.ly/2IJkccg**

Cutting the umbilical [*OE*: Dec 2015]
Eliminating the umbilical has been targeted as a way to help make the exploitation of small pools more viable. **http://bit.ly/2lDFyHy**

Waiting for

2016 was a year of huge challenges for the offshore drilling rig sector as the low oil price environment and reduced E&P spending continued to bite. Stephen Gordon, of Clarksons Research, charts the state of the market, which is arguably facing some of its toughest times since the 1980s.

The offshore drilling market began last year facing up to its worst market for 30 years, and despite a rising oil price, 2016 delivered a raft of gloomy statistics. The long-term perspective and the nature of the current down cycle has parallels with 1986, which, historically, was the lowest point for the oil industry.

Utilization falls to 64%

Across 2016, total working rig utilization fell by 11%, declining from 75% to 64% over the year and to its lowest level since 1986. Putting this in context, working rig utilization finished 2013 at 96%; so the current market is into deep recessionary levels. In January 2017, the working offshore rig count sat at 456 (312 jackups and 144 floaters), dropping by 105 units year-on-year and down from 746 working rigs at the end of 2013.

Dayrates for new contracts also continued to slide downward as cost pressures built, with the global average ultra-deepwater floater dayrate dropping 60% since the peak in 2013 (US$564,000). Now, the dayrate sits close to opex levels at $178,000.

The global average dayrate for jackups has dropped to $93,000, 45% down from the peak in 2013. In contrast to the dayrates for floaters, dayrates in the jackup market were more stable across 2016 and at the start of January 2017, broadly sat a margin above opex. Competition for any tenders is fierce, while “blend and extend” remains a market feature.

Opex levels themselves are down by an estimated 30% from market peak, as the cost-cutting focus across oil and gas filters down through the supply chain.

Regionally, there have been a few bright spots. These areas of optimism are particularly in parts of the world where exploration and production is dominated by national oil companies. As an example, the number of working jackups in India stood at 34 units in January 2017. China also had 34 rigs working. These numbers reflect a year-on-year rise. In the Middle East, activity remained relatively stable at 116 to 108 rigs across 2016.

Supply calibration and future hope?

What could be potentially helpful for the future is more scrapping and stacking of units, which would start to tighten supply. The active fleet – counted in terms of rigs available for deployment – actually dropped by 5% across 2016, with 44 units scrapped and 54 units entering cold stacking.

With the industry looking to move large numbers of rigs out of service, ABS provided guidance with its *Guide for Lay-Up and Reactivation of Mobile Offshore Drilling Units*, which provides a means for defining the status of a stacked unit. It outlines five options for rig lay-up and guidance for maintaining the asset, defining the three basic options: “Laid-up,” “Laid-up Warm Stacked” (with personnel onboard) and “Laid-up Cold Stacked” (unmanned with no personnel on board), and introducing an “Enhanced” status for out-of-service units

the bright side

Laid up rigs offshore Invergordon, Scotland, are indicative of the increasingly common choice among drilling contractors to stack inactive assets. Photo from iStock.

that indicates the unit has had its lay-up location and procedures reviewed to a higher standard and verified by ABS in accordance with the guide. The guide also includes requirements for reactivation that allows surveyors to verify that the unit meets class standards to move onsite and begin operations.

It is increasingly difficult to use the available data to track the exact status of rigs and their ability to re-enter the market precisely, even for assets that recently reached the end of a drilling contract.

Orderbook uncertainty

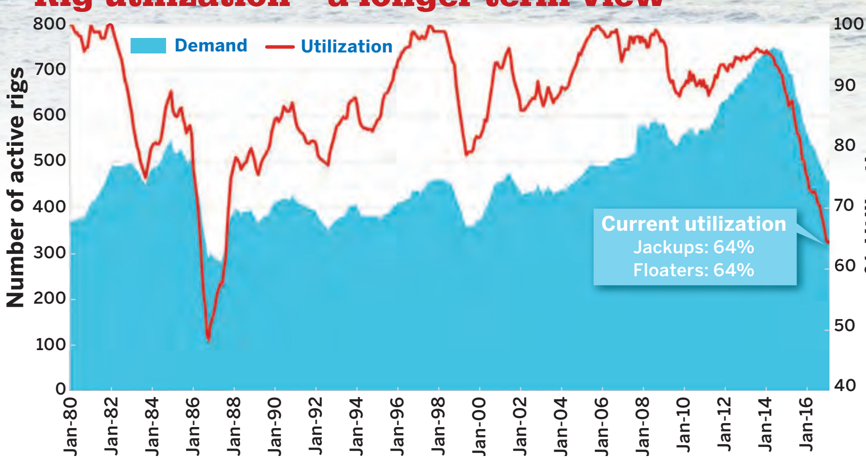
The status of the rig orderbook at shipyards remains largely uncertain. Numbers generated from Clarksons' data indicate that the rig orderbook for 2017 stands at 164 units, with an aggregate original new-build contract value of $60 billion.

It is important to note that while there are orders on the books, delivery dates remain uncertain. Nearly 60% of the orderbook is largely constructed, but it is very possible that these units will remain in yards for some time and in some cases face an uncertain future entirely.

Deliveries from the yards last year fell by 30% as delivery dates continued to slip in the face of the financial pressures faced by rig owners. In fact, there were only three floaters delivered into the market. Slightly more encouraging is the fact that 23 jackups were added to the global fleet during 2016.

As of January, Chinese yards had 65 jackups and 12 floaters on order. Singapore yards had 22 jackups and four floaters on order, and South Korean yards had orders for 19 floaters

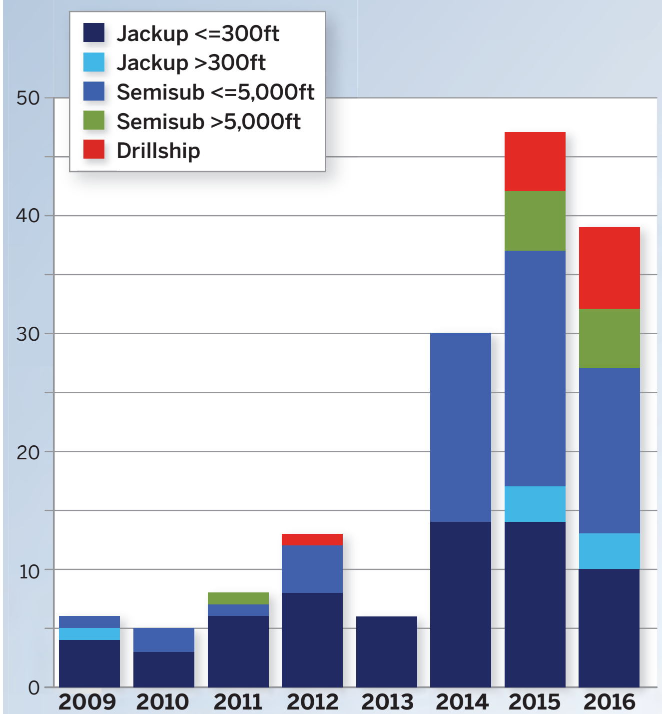
Rig utilization – a longer term view



Long-term rig utilization numbers show peaks in the mid-1980s, in 2008 and 2014, followed by a precipitous drop. Data courtesy of Clarksons Research.

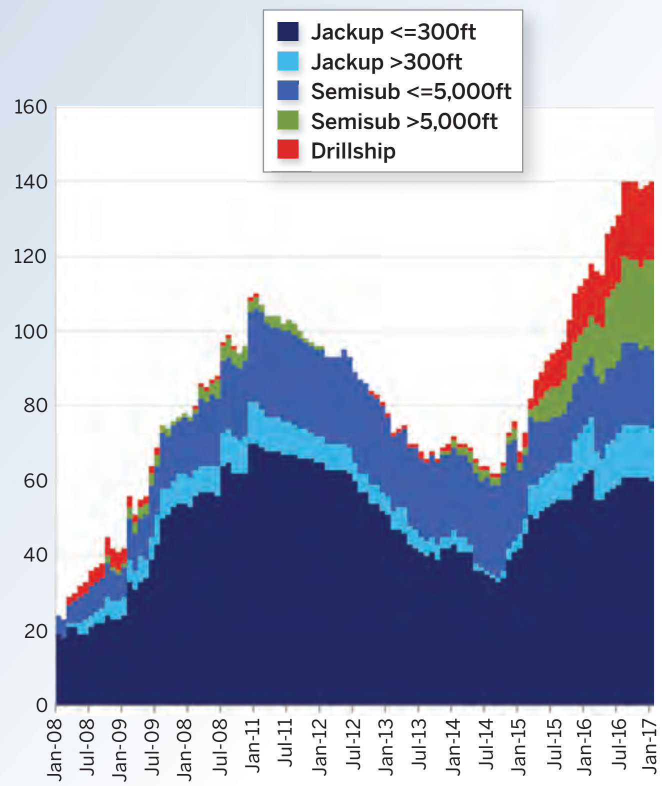
Rig removals

44 jackups and 72 floaters have been scrapped since the start of 2014



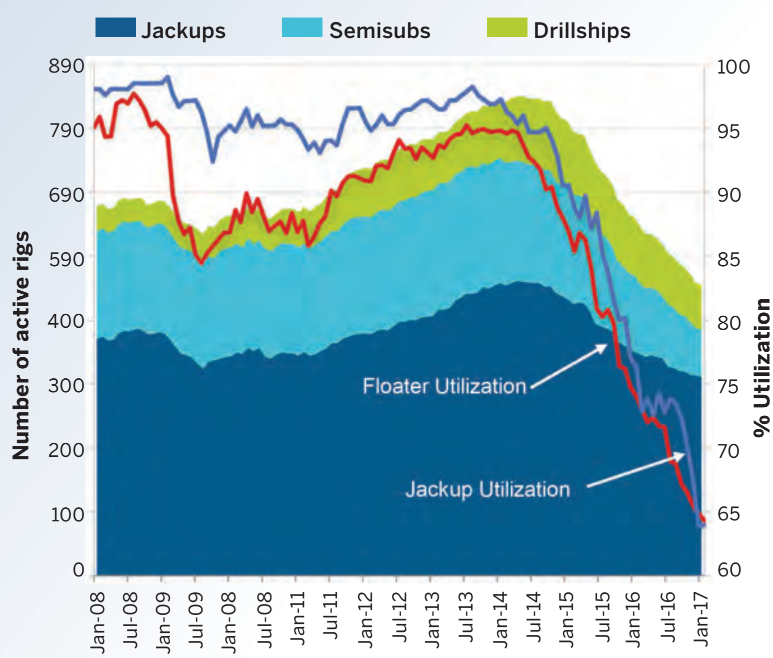
From the beginning of 2014 to February 2017, a total of 116 rigs were scrapped. Data courtesy of Clarksons Research.

Number of cold stacked rigs



The number of cold stacked assets in all sectors was nearly seven times higher in January 2017 than in January 2008.
Data courtesy of Clarksons Research.

Rig utilization



Rig utilization dropped significantly between 2014 and 2017.
Data courtesy of Clarksons Research.

and three jackups. These yards are facing particular pressures in dealing with their orderbook inventory.

Outlook

The immediate outlook remains challenging. Moving toward a significant upside, at least in terms of dayrates for 2017, may be difficult. There are, however, starting to be some signs of improved tendering levels, specifically for jackups and in certain regions of the world (i.e. in the Middle East and India where the rig count is stable or rising) and a greater appetite for acquiring assets, albeit at very "competitive" prices.

While the market may be showing signs of increased activity, it is too early to predict a move toward a more positive picture. More evidence will be needed as 2017 progresses to understand if the market cycle has bottomed out. **OE**

FURTHER **READING**

Reactivating valuable assets [*OE*: October 2016]
With the downturn taking many drillships off the market, ABS' Dave Forsyth and Landon Fields discuss how to bring those ships back up to speed when the market recovers. http://bit.ly/2kSZx5i

Survival mode

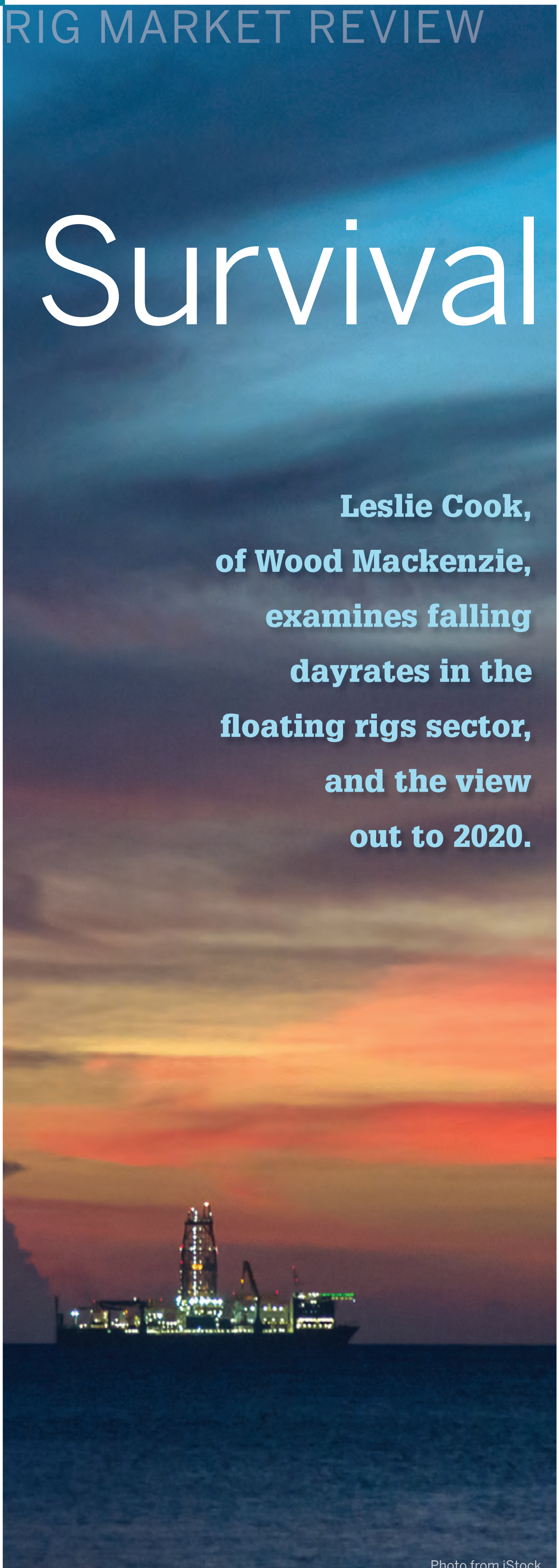


Photo from iStock.

Leslie Cook, of Wood Mackenzie, examines falling dayrates in the floating rigs sector, and the view out to 2020.

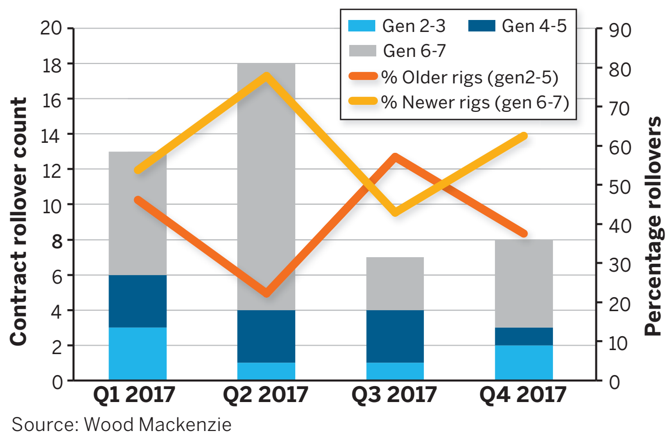
As the cyclical downturn in the deepwater market continues to drag out, drilling contractors are settling into a new way of life. The standard mode of survival rests in the ability to leverage debt, sustain costs, maintain revenue efficiency, and preserve idle relationships with customers and crews.

Contracted floating rig counts have reduced by nearly 30% over the past year and by 50% since the peak in 2014. Over 80 floating rigs have been idled since 2016 and utilization is heading towards 50%. Deepwater ports are filling up around the world as half of the existing fleet is now idle. Roughly three-fourths of older generation rigs are now idle or rolling off contract in 2017, many of which will be permanently retired. Among 3rd-5th generation rigs, hot supply consists of approximately 35 moored units and 10 dynamic positioned rigs.

The pressure to keep 6th and 7th generation rigs in operation is of growing concern among drilling contractors with high exposure to the ultra-deepwater market. These newer generation rigs took a hard hit in 2016 as operators terminated several contracts early in effort to get out from under high dayrates. Term contracts signed at legacy high dayrates back in the peak years of 2011-2012 are now rolling off contract. In 2017, over 60% of the rigs rolling off contract are among this high-specification fleet and leading edge rates for new rigs have plummeted from mid-US$500's to low-$200's causing serious cash flow concerns for firms in the drilling supply chain.

Long-term stacking of rigs causes disruption throughout the supply chain which inevitably will impact operators when the market begins to climb back up. Based on current industry estimates, global oil prices are predicted to stay at or below $60/bbl

Floating rig contract rollovers



Source: Wood Mackenzie

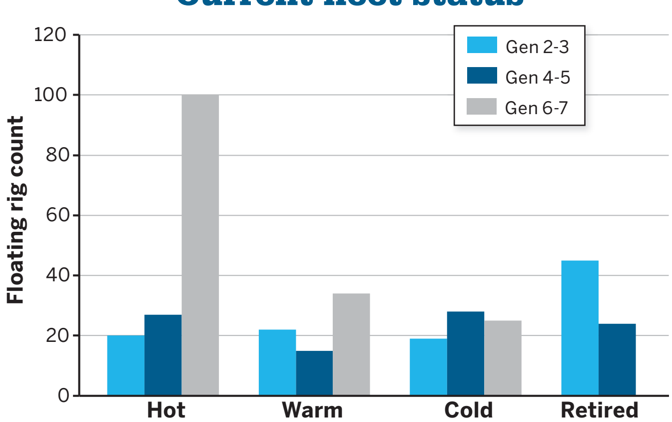
for the next few years, which will keep many of the deepwater rigs idle through 2019. With very little precedence to go by, the true cost of reactivation is still unclear. Publically disclosed estimates of $25-$35 million for reactivation of a 6th generation drillship only covers capex estimates, which are incurred by the drilling contractor and do not reflect the true overall picture of putting a rig back to work. There are 100 newer generation rigs in hot mode today (fully crewed and operable), but only 20% of the units have firm contracts into 2020. Despite efforts to keep rigs as warm as possible, long-term idle time will likely result in fewer economical choices for operators in 2020 versus what is available today.

Keeping a rig hot is not an easy task under current market conditions. With limited opportunities for new fixtures, there is heavy emphasis to maintain revenue efficiency (measure of how much a rig earns while under contract). Every drilling contractor in the deepwater space must maintain strict financial and operational discipline in order to keep contracted rigs under full rate at the lowest possible cost without compromising safety. So far drillers appear to be up to the task as the major contractors are maintaining revenue efficiencies above 95% with razor thin margins and no major safety incidents. Over the past two years, as dayrates have continued to free fall, drilling contractors have successfully reduced daily operating costs by upwards of 30% by reducing onshore logistics, manpower, and wages.

Currently, there are 147 floating rigs under contract of which roughly 80% are working. Among the working fleet, 45% are operating in Brazil and US Gulf of Mexico. Total well demand in 2017 is forecast to drop another 10% with declines expected in both exploration and development programs. As a result, rig demand is expected to be somewhere around 110 units average for the year, so we expect to see a continuation of rigs going idle at the end of their contracts, and contractors will fight to get one well at a time in an effort to keep rigs hot. Long-term fundamentals favor a return to deepwater activity, but the climb up is poised to be even more challenging than the fall. OE

__Leslie Cook__ is a principal analyst in the Upstream Supply Chain Group at Wood Mackenzie. She is recognized for her sector expertise in the supply and demand dynamics of the offshore drilling market.

Current fleet status



Source: Wood Mackenzie

Ultra-deepwater supply facing steepest recovery

Overenthusiasm in the recent floating rig building cycle has led to an ultra-deepwater "hangover" that will take several years of recovery, says Liz Tysall and Oddmund Føre, of Rystad Energy.

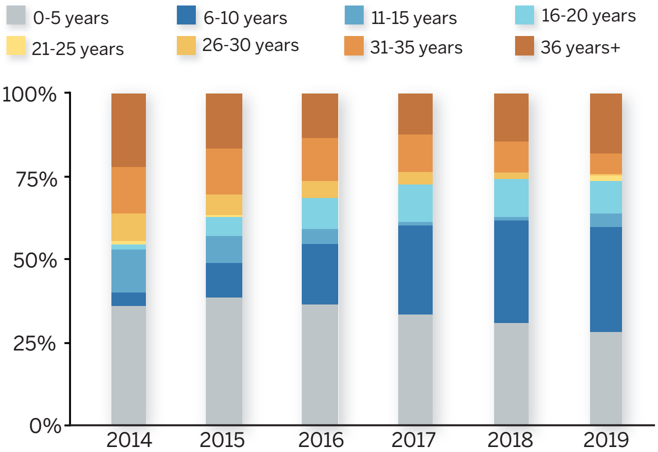
Although drilling contractors are scrapping floating rigs at a relatively decent pace, removing only older rigs will not correct the looming supply over-hang in the ultra-deepwater market. Cold stacking in the ultra-deepwater market will close the gap, but will not resolve the problem long-term.

Utilization statistics

As we head into 2017, utilization of the competitive floating rig fleet stands at 47%. This compares to early 2014 when utilization was at 85%. As oil prices started declining in 2014, drilling contractors were reading the writing on the wall and rig attrition began in earnest. By the end of 2014, 19 floating rigs exited the fleet, followed by 27 during 2015 and 24 during 2016. Since 2014, taking into consideration rig attrition and new entrants, the annualized rate of decline for the competitive floating rig fleet has been approximately -6%/yr. Rig attrition announcements slowed slightly towards the end of 2016. Based on research by Rystad Energy, we expect retirements of between 8-10 floating rigs during 1H 2017.

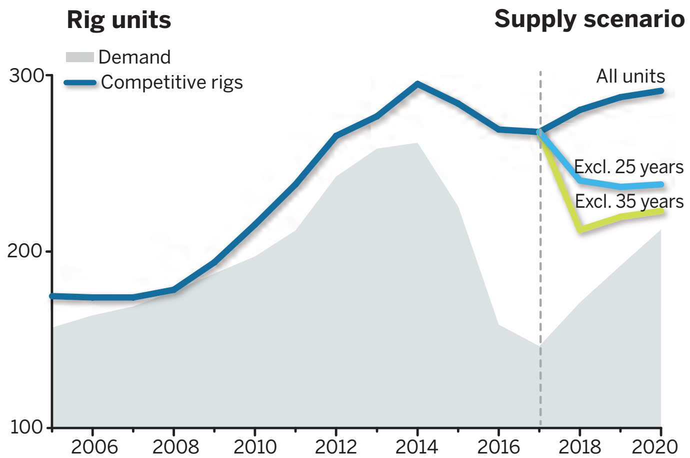
Taking a closer look at some statistics, 39% of the idle floating rigs have delivery dates prior to the year 2000. The SPS (special periodic survey) on 20% of these units has lapsed and another 54% have surveys that will come

Figure 1 - Current competitive floating rig fleet composition by age



Source: Rystad Energy RigCube

Figure 2 - and competitive rig supply by rig unit



Source: Rystad Energy RigCube

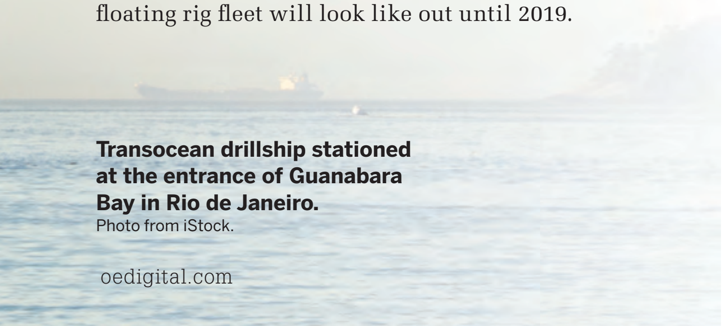
due during either 2017 or 2018. For those units with surveys coming due within the next two years, only seven are ultra-deepwater. Of the remaining units, nine are deepwater and 13 are midwater.

Re-shaping the floating rig fleet

Setting aside SPS due dates, hypothetically, if only units that were 25+ years old were removed during 2017 and all newbuilds (excluding Brazilian newbuilds) scheduled for delivery entered, this would bring the 2017 competitive fleet down to 205 units. Which is closer to levels seen just prior to 2010. Removal of these units changes the composition of the fleet into 13 midwater units, 12 deepwater units and 180 ultra-deepwater units. While this is drastic, only a couple of drilling contractors would be "out of business," so to speak, and making a few others pure jackup contractors.

Given the number of stranded newbuilds and the state of the shipyards, these contractors could theoretically refresh their fleets. However, the market is not quite at the point where drilling contractors are willing to take on the additional expense of acquiring newbuilds. Thus far, only two drilling contractors have announced acquisitions. These two separate transactions involved three units and only one of these units had a contract in place. As to the other two rigs, one was immediately cold stacked and the other is still under construction. In making adjustments to what the fleet would look like in 2018 and 2019 by removing units 25+ years old and adding newbuilds to the fleet, we could expect to see competitive supply at approximately 213 units and 220 units, respectively. Without removing any units 25+ years, the competitive supply in 2018 and 2019 would be 281 units and 286 units, respectively.

Based on announced newbuild delivery dates and rig attrition to date, Figure 1 depicts what the composition of the floating rig fleet will look like out until 2019.



Transocean drillship stationed at the entrance of Guanabara Bay in Rio de Janeiro.
Photo from iStock.

Ultra-deepwater supply overhang

Retirement of floating rigs older than 25 years dramatically highlights the supply overhang in the ultra-deepwater market. It should be noted only five rigs in the ultra-deepwater market are older than 25 years. One is working, one is warm stacked and the remaining three are cold stacked. For the remainder of the competitive ultra-deepwater fleet, 8% have SPS that has lapsed while 30% have surveys due in either 2017 or 2018. Within the subset of the younger ultra-deepwater competitive fleet, 36% are cold stacked. Removing these cold stacked rigs from the active fleet is just at the breakeven point for newbuilds scheduled for delivery between 2017 and 2020, (excluding Brazilian newbuilds).

Road to recovery

Rystad Energy's base case oil price scenario implies that oil will average at US$62/bbl for 2017 followed by a steady recovery towards 2020 and a real oil price of $90/bbl. Several factors that will contribute to an increase in floating rig demand: an increase in infill drilling demand; previously deferred FID (final investment decision) sanctions moving forward; and exploration activity growing on the back of cost compression across the offshore sector. Figure 2 highlights demand with competitive floating rig age-based attrition scenarios.

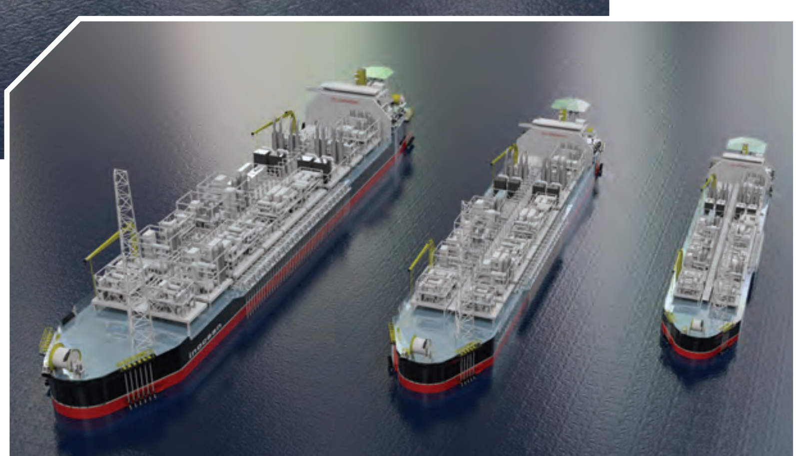
While data from RigCube indicates demand for floating rigs will begin to pick up in 2018, retirements need to continue at nearly the same pace as the past three years to help bring the market closer to being balanced. **OE**

Liz Tysall *is a senior analyst at Rystad Energy and joined the Houston office in 2016. Prior to Rystad, Liz worked for Rigzone for 18 years and brings with her a sound knowledge of the oil and gas industry with a focus on the offshore driling market.*

Oddmund Føre *is a senior analyst and product manager of RigCube. His primary focus is on the analysis of the global offshore drilling market as well as the production and spending on the Norwegian Continental Shelf.*

Neural networking by design

Artificial neural networks are being used to help design floating production system hulls in the concept and front-end engineering phases. Elaine Maslin reports.



Libra and her possible smaller sisters generated using artificial neural network technology. Images from Inocean.

Artificial Intelligence (AI) has long been an idea confined to science fiction films. But, the use of AI is creeping into our daily lives: think about Siri on your iPhone telling you how long it will take to get home.

The power of processing – artificial neural networks, specifically – is also starting to make a mark in floating production vessel design for the offshore upstream industry.

Artificial neural networks (ANN) are a type of information processing inspired by how biological neural systems, such as the brain, process information. ANN systems are composed of a large number of highly interconnected processing elements (i.e. neurons in the brain) working in unison to solve specific problems.

What makes them useful is that they, like people, learn by example. They can be trained (values are given weight and treated accordingly) and can be configured for specific applications, such as pattern recognition or data classification. To oversimplify it, if you fed one (which has been purpose designed) a pile of floating production, storage and offloading (FPSO) vessel design data, it would learn from the data and be able to do the analysis that you need for initial sizing of new FPSOs.

This is Norway-based Inocean's aim. Inocean, founded in 1996 (but, now part of TechnipFMC), is a naval architecture firm focused on floating production vessel design, with 30 FPSO newbuild and conversion projects under its belt. It also has bright young engineers who want to work with ANN techniques.

Frode Kaafjeld

"We have a lot of information and data [from] over the last 20 years that we want to use," says Frode Kaafjeld, managing director, Inocean. "This new technology [ANN] opens up new ways of using this data."

By using existing data (former FPSO designs), you can train an ANN with an iterative algorithm to estimate the functional relationship between the input (main dimensions, draft, block coefficient etc.) and the output (hydrodynamic sectional loads).

Normally, in the concept or front-end engineering and design phase, various iterations of an FPSO design will be evaluated, to find an optimal design within a set input criteria (storage capacity, risers, metocean conditions, etc.), which is a time-consuming process because it includes calculating hydrodynamic sectional loads – for each iteration.

This means using the likes of linear diffraction/radiation analysis and stochastic post-processing. Using an ANN estimator speeds up the entire process.

"In order to speed up this process, we together with Technip are developing an automated iterative algorithm for sizing of FPSOs," Kaafjeld says. "This algorithm works through numerous size combinations and automatically recalculates the effects on weight, stability, motions, etc., by integrated routines."

ANN is not new. It was first developed in the 1950s and 1960s, but the use of graphics processing units found in high-end graphics cards has helped the creation of so-called Deep Nets, enabling computers to beat humans at quite complex games, such as the complex Chinese board game Go. For FPSO design, however, this level of system isn't necessarily required, says Espen Engebretsen, one of the new generation MSc Naval Architects (born 1987).

Espen Engebretsen

Inocean is drawing TechnipFMC's FIDE (Floater Integrated Design Environment), a sizing tool that enables a trained user to perform sizing of spars, semisubmersibles and tension leg platforms (up to scantling level for class approval). Inocean and TechnipFMC have cooperated to include sizing of ship-shaped FPSOs into FIDE and are currently working on integrating the ANN for estimation of hydrodynamic sectional loads.

"Within FIDE we have seen a great advantage of estimating hydrodynamic sectional loads without having to utilize the traditional diffraction/radiation analysis, which becomes very time consuming when a large number of size iterations are evaluated," Engebretsen says. "By using [ANN], we have been able to create an estimator, which utilizes Inocean's vessel database to instantly estimate hydrodynamic sectional loads."

While the tool's development can take months (with the data it was fed carefully selected to provide an adequate representative database), and the algorithms built, the training is fast and once it is done, the results are also fast, Engebretsen says.

"Work only took a few months," he says. "ANN can be configured in multiple ways. What took time was optimizing it and avoiding some traps."

Inocean has trialed the system, performing initial hull sizing, but then verifying the results using traditional manual calculations, with positive results. As an example, the firm has produced indicative designs for sister vessels to the Libra FPSO (an Inocean design), using parts of the ANN algorithm it developed. The image shown depicts how the ANN algorithm works – how the designer can trim the design until a desired result is achieved.

Of course, this is a conservative industry. Classification societies will not allow a design produced this way to be classified. What the tool can help with is getting through the initial iterative process faster, as the optimal hull size is obtained in a shorter amount of time, i.e. potentially helping to reduce costs, and before starting traditional calculations. The system is also being continuously developed and improved.

"We still believe that we need to do the traditional hydrodynamic and structural hydrostatic calculations for the design, but as time goes by we will be able to integrate this analysis more into our tools," Kaafjeld says.

A tender could be produced far faster, with options given, which can be quickly altered according to a changing specification – additional risers, bigger tanks, etc. What's interesting for Kaafjeld is that a new generation of engineers are pushing these techniques, but working alongside more experienced engineers.

And hopefully, just as this technology is showing its capability in FPSO design, Kaafjeld thinks the FPSO market might be growing again.

"The market for FPSOs in general seems to be growing again," Kaafjeld says. "A lot of projects seem to be starting up again. After the drop in the market, we see clients that are more demanding and more conscious of what they want. They want more optimized solutions, they want cost-effectiveness and there is the 'green' dimension. All this is affecting the design of FPSOs."

Just as individual humans are not quite ready to put their lives in the hands of AI, floating production systems will not yet be fully designed using ANN. But, AI certainly has a part in making the process faster, reducing the time and effort required in that otherwise long iterative design process. OE

EPIC

Fixed platforms, shifting markets

Infield Systems' Neda Djahansouzi gives a flavor of the forecasted fixed platform market in 2017-2021, while we let some figures speak for themselves.

Over the past two years the offshore sector has undergone an extremely challenging period and the fixed platform market has been no exception to this.

Infield Systems' Global Fixed Platform Report to 2021 expects the fixed platform market to comprise 13% of total offshore expenditure during the 2017-2021 timeframe.

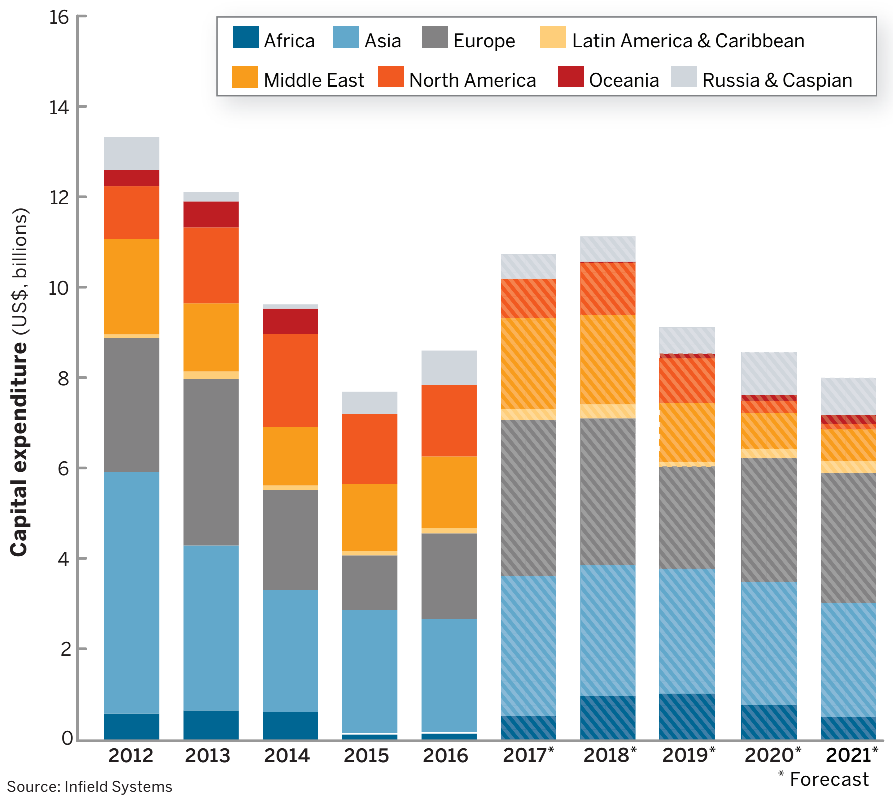
The report, which highlights key trends within the fixed platform market over the next five years; including expected capex and installations globally, demand drivers and contract activity, sets out a shifting picture, as traditional markets give way to lower cost basins.

A diminishing US Gulf of Mexico, North Sea and parts of Southeast Asia account for a shift in the fixed platform market from its traditional Europe- and Asia-driven markets, to activity increasing in non-core, low-costing geographies, including Vietnam, Russia, Venezuela and Iran.

Despite this, Asia and Europe will continue to lead the global fixed platform sector in terms of capex spend, over the next five years, driven largely by the development of Statoil's Johan Sverdrup field, one of the five largest oil fields on the Norwegian Continental Shelf.

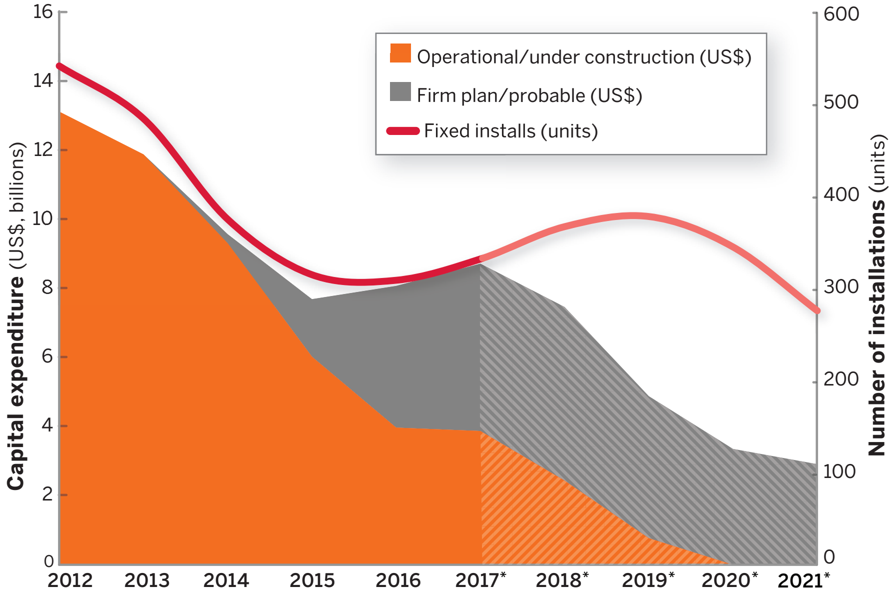
In Asia, demand is underpinned by shallow water activity in Malaysia and Vietnam towards the end of the forecast, as well as increased demand in China between 2019-20, because of investment in CNOOC's Lingshui and Peng Lai developments. OE

Fixed platform capex by region, 2012-2021



Source: Infield Systems

Fixed platform buildout, 2012-2021



Source: Infield Systems

A seismic shift – pun intended – has been made in ocean bottom node technology. It is being made more efficient and cheaper to deploy, bringing it closer to challenging the high-end towed streamer market. Elaine Maslin reports.

Taking seismic to the seafloor. Magseis' MASS system deployed using an ROV. Image from Magseis.

Starting from the (ocean) bottom

While ocean bottom seismic (OBS) is not new, it has, until now, been something of a niche within the wider seismic, towed streamer dominated technology market.

The technology puts seismic sensors on the seafloor, where they collect high-quality, full azimuth data, often in 4D mode, for reservoir monitoring. Ocean bottom node (OBN) technology offers a flexible, high-quality seismic solution, but, its higher cost has held the technology back, until now.

Huge strides have been made in reducing node size and weight, and in developing automated handling systems – for both remotely operated vehicle (ROV) and cable/rope (node on a rope) deployments. This enables far faster surveys, thereby reducing costs.

OBS firms are adding to their inventory and mobilizing additional crews, as they expect their market to grow – and not just in the reservoir monitoring market. They think this technology could also be cost-effective for exploration surveys, which traditionally cover wider areas.

"We believe [OBS] is going to take a bigger part of the exploration market," says Petter Steen-Hansen, vice president, sales and marketing at Norway's Magseis. "Already, a year ago, we did our first multi-client survey in the Barents Sea for exploration purposes.

Miniaturization in practice. Magseis' latest node. Photo from Magseis.

The feedback was very encouraging. [Operators] see it as having potential for certain areas where there is complex geology. As we increase efficiency and reduce cost, we think there is definitely scope for more 4D operations and certain exploration areas."

"People now see that acquisition cost is coming down to a cost level that is competitive with traditional towed streamer technology," says Vidar Hovland, CEO of inApril, a relatively new Norwegian OBN system supplier. "We saw in the 1990s, when the 3D streamer vessels started towing more streamers, and the cost came down, that the market responded fairly quickly. We believe that we will see the same now, that OBN will take a portion of the streamer market as costs come down closer to streamer seismic."

2017 could be the year things rebound for OBS. "We expect that, if the oil companies maintain their current seismic budgets, the 2017 OBS market will be back up to that of 2014," says Chris Walker, chief geophysicist at Seabed Geosolutions (a CGG, Fugro joint venture). Industry estimates put the 2014 market at about US$850-900 million, while it had dropped to an estimated $390 million in 2016.

Starting at the bottom

To date, OBNs, which usually contain four components (i.e. 4C: one hydrophone and three geophones), have mostly been used for reservoir characterization and monitoring. Thousands of nodes are laid on the seafloor, using remotely operated vehicles (ROVs) or cable on grids up to a few hundreds of meters apart. Vessels towing the seismic source sail over and the nodes collect the reflected data (instead of receivers on streamers towed behind vessels). The data is downloaded when the nodes are retrieved and the batteries recharged or replaced.

By putting the receivers on the seabed, instead of on long cables behind source vessels, the signal to noise ratio is reduced. Seabed nodes can also gather both shear and pressure waves, and offer full azimuth coverage, all of which adds up to very high quality data and an ability to see where other technologies struggle. Nodes can also be deployed where streamers cannot go, i.e. around existing infrastructure.

ROV positioning accuracy enables accurate repeat surveys for 4D surveys. Cable, or node-on-a-rope, positioning is generally seen as getting less accurate as water depth increases – although this is being challenged.

Past issues

In the past, issues with nodes have been around battery life, size (largely due to the large batteries), and slow, inefficient deployment and recovery. In some cases, this meant having to do a survey in chunks, retrieving and redeploying nodes multiple times in order to cover a set area, while source vessels waited.

In the past, a typical deepwater node setup would see nodes deployed 400m apart, with source shot over them on a 50m grid, on X and Y axis, Walker says. Sensors were deployed sparsely, to keep down ROV vessel costs, with denser shot grids (from the cheaper source vessels) to compensate. Even then, because of the time it took to place the nodes, using ROVs, the source vessels would have to wait 2-3 days after node laying started before they could start working. Node spreads would possibly need to be laid, shot over, then picked up and moved to the adjacent area, but with overlap, and then another shot run, which was also inefficient.

"Historically, even with two ROVs, you would be deploying 80-100 nodes a day, maximum, on a 400m node grid," Walker says. "With smaller new generation nodes, with comparable node spacing, you are able to, at a minimum, double that deployment rate, which means we can handle nodes fast enough to allow rolling receiver spreads with two dual source shooting vessels operating simultaneously."

Previously, laying nodes was the normal project critical path activity, but now it's the source vessels, says Martin Hartland, executive vice president, performance, at Seabed Geosolutions. "As multiple source vessels start shooting simultaneously, thanks to faster node handling, that's when you can get three-, four-fold improvements in production and a significant reduction in the overall project cost. That's where we are," Hartland says.

Miniaturization

Reducing node size has been key. The size and weight reduction has been aided by using micro-components and micro-electronics, helping to reduce power consumption, as well as advances in rechargeable battery technology, for those who use rechargeable batteries. Node designs have also been optimized, which, together with the introduction of automated handling systems, has allowed for greater numbers of nodes to be stored, charged, data downloaded and deployed again faster.

"The small size of our MASS I nodes, at about 8kg, allows us to create a much more efficient and portable system and virtually means we can carry an unlimited number of sensors," says Magseis' Steen-Hansen.

The firm's 65-day battery life Marine Autonomous Seismic System (MASS I) nodes, weigh 8.35kg, are 227mm-long, 160mm-wide, 88mm-tall,rated for 3000m water depth, and can be deployed by ROV or by inserting the sensor capsules into casings on Magseis' own automated cable system. A few years ago, nodes were weighing in excess of 60kg. Magseis also recently launched a MASS III node with 150-day battery life.

"Everything is containerized and fully automated, which means they could be deployed on ROV vessels already on hire by a client within a field," Steen-Hansen says. "Robots change the batteries, dock them and download data. The small size enables us to do that."

Magseis' MASS nodes were designed around using an atomic clock, for timing, and positioning accuracy. They have a 32-bit analogue to digital resolution, Steen-Hansen says. "Some of the technical specifications are leading edge sensor electronics," he says. "The company has been inspired by miniaturization from the mobile phone industry and does a lot of research and development in Sweden. We are raising the bar of what's achievable and it doesn't stop. It's all about more inventory, fast deployment and reducing overlap and source acquisition," he adds.

Magseis has mostly deployed its nodes with its automated cable system. But, this year it will do its first full-scale ROV deployed project, with ConocoPhillips in the Norwegian sector of the North Sea. Some 3000 MASS I nodes will be deployed from a vessel of opportunity – another first for Magseis, which has been using its cable spread on the *Artemis Athene*.

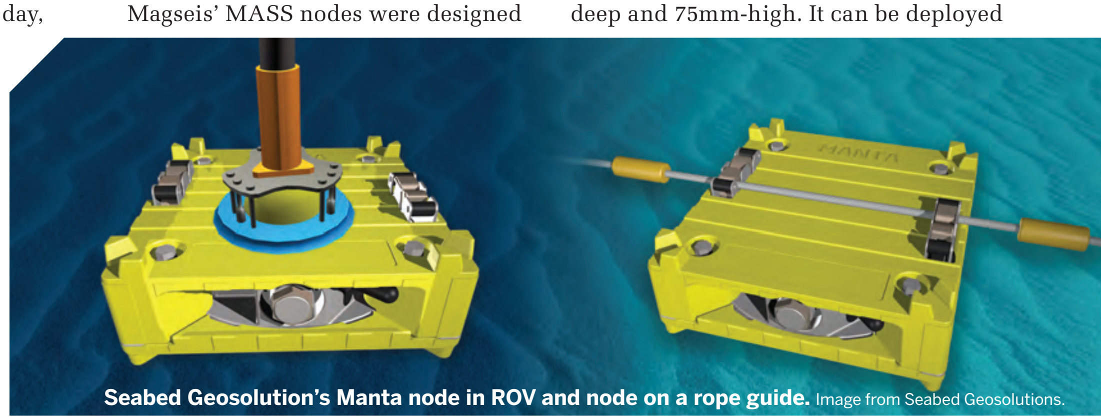
The nodes, because they're so small, will be deployed in large batches via a skid on an ROV, reducing the time needed for the ROV to travel through the water column and eliminating the need for a subsea basket from which to collect nodes, a technique others also use. Two ROVs will work in parallel from the one vessel, which will traverse between the middle of two receiver lines. "Because our nodes are very small, we can carry a lot more so that we don't need a basket solution," says Steen-Hansen, although he wouldn't give away numbers. "Each ROV can carry significantly more nodes on each run and, therefore, increase the deployment efficiency."

Smart systems

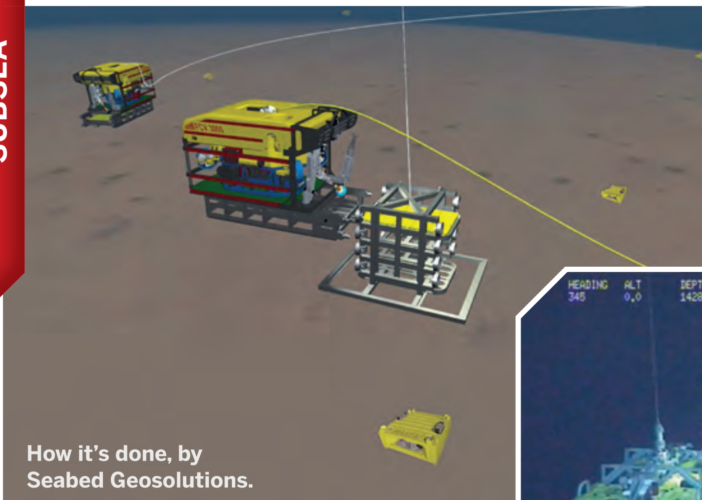
Seabed Geosolution's latest generation node, the 3000m water depth-rated Manta, weighs 15kg in the water (a previous generation weighed 65kg) and now measures 350mm-wide, 350mm-deep and 75mm-high. It can be deployed by ROV or on a rope/wire, and will work for 75+ days in -5°C to 40°C.

Some 900 Manta units can be stored in a standard 20ft container, which, along with the deployment system, can be deployed on a vessel of opportunity, for deployment by ROV or, with the addition of an additional attachment and rope module, it can become a node-on-a-rope system.

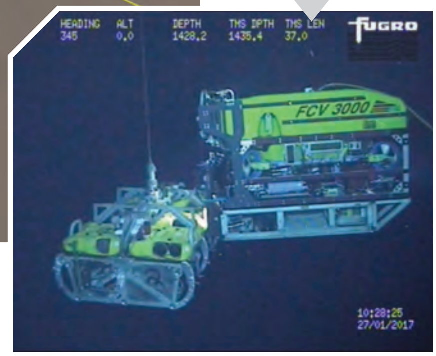
This year, Seabed Geosolutions is due to launch its first large-scale 4C/4D Manta OBN crew, with the nodes due to be delivered in Q2.



Seabed Geosolution's Manta node in ROV and node on a rope guide. Image from Seabed Geosolutions.



How it's done, by Seabed Geosolutions.



A mid-water transfer of Seabed Geosolutions' Case Abyss Nodes, while sailing between two node deployment lines at 0.7 knots.
Images from Seabed Geosolutions.

"The size reduction allows a single ROV, generally working in tandem with a second ROV, to carry a tray of 21 nodes at a time, instead of one-eight (node type dependent), we have seen in the past," says Hartland. The trays are retrieved from a subsea basket containing two, 21-node trays, keeping reload requirements down.

To avoid any turbidity created by putting the basket on the seafloor, the basket is suspended in the water column near the seabed and a mid-water transfer takes place. Using pixel or image recognition software, the ROV will dock and lock on to the basket automatically, removing the need for difficult manual ROV manipulation and allowing the surface vessel to maintain a steady 1.5 knots. All of this automation is commanded from an integrated navigation and control system, which connects the ROVs (and node positioning), their respective tether management systems (TMS), basket position, the ROV vessel position, and the source vessel position, through one integrated command and control system, Hartland says.

"We can also control the seismic source vessels, ROV and other navigation systems from one integrated navigation control system," says Hartland. "That's the enabler, automating the node laying system. It is a big step forward. Laying nodes on the seafloor is a very repetitive activity. The ship goes along a sail line, two ROVs, 200m each side of the ship lay nodes every 200-300m. It's very repetitive and, today [in current generation systems], that's done by people."

Software

Control systems and simulation are also playing their role in making these systems more efficient. Seabed Geosolutions is using Fugro DeepWorks, a simulation program, which helps train pilots ahead of a job, and actually also helps plan out the job, using physics engine software. "Using time domain physics-based simulation, you can fly missions in a simulated environment using the actual ROV console," Hartland says. "We've taken that and adapted it to two vehicles at once. When we plan projects, we put in the seafloor from multi-beam echo sound data or Lidar data, then fly the mission over the same seafloor terrain."

This can include a floating facility's mooring system, risers etc. or an extreme terrain, which would help plan out the optimal height to position the TMS and enable greater understanding and control of umbilicals' and tethers' catenaries, reducing wear and tear, and operational risk and highlighting areas for further operational optimization. Because it's a physics engine, it can model the whole operation, including active heave compensation effects and current profiles. "These tools and systems allow us to be more productive and more certain of our performance before entering an area," Hartland says.

On the ropes

Automation is also improving node-on-a-rope operations, where previously a human had to hook each node onto the "rope" as it was deployed. Now the process is hands free and automated, from storage to the wire and to the seafloor. Because the node is on a rope, or wire, and deployed continuously, node-on-a-rope deployment is much faster than ROV deployment, especially with dense inline configurations, making it potentially more attractive for exploration work.

In 2016, Magseis laid 350km of continuous cable with its MASS I nodes, for a project with BGP Arabia in the Red Sea (in close to 0-1100m variable water depth), which continues into this year. Magseis' latest cable spread, due on the market this year, will have 1000km of cable with 10,000 MASS I nodes – all to be deployed from one vessel using an automated system and down to 2000m water depth.

It's quite a step-change. Steen-Hansen wouldn't give deployment rate figures, partly due to the variability that these could be, depending on water depth and seabed topography, but he said the firm was confident it was market-leading.

Furthermore, Steen-Hansen says that the nodes, when inserted into their casings along the cable, have a shape and weight density that enables improved positioning accuracy, offering the potential for 4D work, where repeat positioning accuracy is needed, even as the system goes into deeper waters, in excess of the 1100m, achieved in the uneven seafloor topography of the Red Sea.

inApril is also chasing fast node-on-a-rope deployment speeds. The firm is looking to prove deployment speeds up to 6 knots this year, and Hovland thinks that node-on-a-rope can be efficient in up to 1500m water depth.

inApril was set up to be an equipment supplier, with the same node and system for shallow and deepwater, whether deployed by rope or by ROV. The firm says the system can work down to 3000m and that 10,000 nodes could be handled from a vessel of opportunity via node-on-a-rope using an inApril automated system, or via ROV with the contractors' own methodology.

inApril's Venator (hunter in Latin) A3000 nodes are 300mm x 300mm, 110mm high, weigh 22kg and have a 100-day rechargeable battery life. The firm's automated system tracks all nodes' statuses and selects deployment sequence, as well as controlling the speed and the node spacing along the rope.

The firm has built and tested all the critical components for its system and ran a commercial trial in the northern Caspian Sea in November for Geo Energy Group. A more extensive 50-node test is due to start early this year, to demonstrate a 6 knot deployment with an oil company in the Norwegian sector of the North Sea.


Tightly packed: inApril's node system.

Light packaging: inApril's node and node system. Photos from inApril.

MASS en-MASS

As part of a joint development project with Shell, Magseis is working on a system to deploy MASS technology in ultra-deepwater with positioning accuracy for 4D work, using a towed subsea vehicle, from which the nodes are automatically deployed. A full-scale pilot test in >1200m water depth was completed in Q3 in a Norwegian fjord. Steen-Hansen says that first commercial operations are planned for 2018.

"We recognize that for deepwater and certain types of deployment, ROV could be a good solution," Steen-Hansen says. "But, if we really want a step change, something else is needed."

Flying nodes

There are also systems in development that wouldn't need any type of vehicle or cable for deployment – so-called flying nodes. ***OE*** covered Autonomous Robotics Ltd's (ARL) flying nodes concept last year (*OE*: February 2016). The concept stage for ARL's system is complete and a tethered version of the first prototype flying node will start in water testing during 1H 2017. Seabed Geosolutions is working on a similar product, dubbed spicerack nodes, with Saudi Aramco.

Another alternative is using nodes for long-term, or permanent reservoir monitoring. However, with the increased efficiency of today's node laying operations, Walker thinks permanent systems will be an inefficient use of a capital asset.

Retrievable systems, compared to permanent systems, offer more flexibility and scalability, Steen-Hansen says. "You can have flexibility in survey design, if you want it bigger or smaller, depending on how the reservoir develops and scale it accordingly," he says. "You're also not locking yourself into one technology for a long period of time."

Either way, OBN technology seems here to stay. "The future is on the seafloor," Walker says. "I joke that, when people join seismic vessels in the future, people will say to them 'you know they used to tow sensors.'" **OE**

FURTHER **READING**

Making nodes fly
[*OE*: February 2016]
http://bit.ly/2kJvKwM

ERD wells push distance boundaries

Scott Weeden looks at new developments in extended reach drilling, which include managing vibrations, thereby allowing the BHA and bit to stay on bottom longer and get the well to total depth.

The slip-on Python Polymer Rotating drilling centralizers/stabilizers are installed on drillpipe. The tools provide up to 60% wear reduction, torque and drag reduction and less stick/slip and associated vibration.
Photo from TDTECH.

Extended reach drilling (ERD) is not about a new piece of technology. Sometimes the operator and service provider have to focus on some of the simplest equipment—cement plugs, centralizers, stabilizers and drillpipe—to ensure success.

The benefits can be far reaching. The current world record for an extended reach well is set at 44,291ft (total measured depth), drilled by ExxonMobil, extending from onshore Sakhalin Island in eastern Russia out into the Sea of Okhotsk. This has helped the supermajor reduce the number of offshore facilities it has had to construct at Sakhalin to two.

"Operators are now drilling to 44,000ft quicker than we used to drill the 26,000ft wells," says Iain Hutchison, managing director at Scotland-based Merlin ERD.

Education, education, education

Achieving such feats is about education. Hutchison points to Chevron's MAXDRILL and ExxonMobil's Fast Drill programs as examples of significant pushes in educating drill crews on how to avoid drilling problems and drive continuous improvement. According to ExxonMobil, its drilling rate has improved more than 80% since introducing the Fast Drill process. In fact, ExxonMobil has drilled more than 80% of the top 50 longest ERD wells.

"Let people understand what it takes to drill these wells," Hutchison says. "Often the skills and intelligence of the people on the rigs aren't being fully utilized. We're not showing them why these wells are different. They're coming from drilling less challenging deviated wells, or sometimes vertical wells, to suddenly drilling complex, high-angle wells, and wondering why they're getting stuck," he adds.

Merlin, which is an ERD and ultra-long lateral (ULL) engineering consultancy, supports its engineering work with a three-day operations course with instructions that are objective, enabling the rig hands to have the knowledge they need.

"The human factor is an absolute key. We've seen time and time again when some of the best programs and engineering fail because the office hasn't made it clear to the guys on the rig what is different about this well or explained why the instructions are written [a certain] way," Hutchison explains.

The company builds on a basis of engineering, fundamentals and physics, adding some local conditions or problematic formations for the outline of the course. After the first half-day, the rig hands all start contributing and discussing problems as well as successes.

While drilling a 44,000ft well, if something goes wrong at 27,000ft, it will have major cost and operational implications. "We focus on where the problem could occur, to avoid it. About 80% of the problems tend to be procedural or human factors," Hutchison says.

Planning and execution are critical

Big data is also used in both the

planning and execution of an ERD well, according to Halliburton. Today, every bit of data can be used and analyzed automatically in real-time and then used to benchmark future operations.

"The industry, through specialized software packages, has the capability to do automatic classification of rig activity with very high accuracy and definition," says Wael El Deftar, Sperry Drilling chief global advisor, at Halliburton. "We can start to benchmark our performance on every single activity from the moment the well is spudded until the moment it reaches total depth. Over time, we can start to identify and quantify where we are spending too much time for no reason (hidden non-productive time).

"We can start doing performance comparisons well-to-well, rig-to-rig, crew-to-crew and field-to-field. We can standardize performance by capturing the areas where we are excelling and supporting the crew's efforts. We also find the areas to reduce inefficiency," he explains.

Halliburton does a comprehensive risk analysis method as one of its approaches. The company analyzes the data and finds what types of problems will be faced during the ERD well execution. "We start to put measures into the design to overcome this risk in case it materializes. We call this approach the Global Drilling Risk Factor Method. It allows us to be prepared for contingencies," he continues. "Even if we run into trouble, we don't have to spend much time on this problem because we have the contingency plans available. That's how we can improve performance."

The company has a worldwide engineering group called the Drilling Engineering Solutions Group to deal with challenges such as ERD project planning.

Blending old, new technology

While new technology is always a great attraction, getting more out of existing technology or even using it correctly also has huge value, Hutchison says. "We frequently come across opportunities that can be delivered with a bit of clever engineering, rather than a costly rig upgrade, which was perceived to be 'essential.'"

One example of using an older technology correctly is pumping cement plugs. "When a well is drilled, cement plugs are pumped. It's very simple. But, have most operators pumped a cement plug to 30,000ft? It was good for wells at 15-16,000ft, but now the plugs are being pumped twice as far. It's little things like that," he adds.

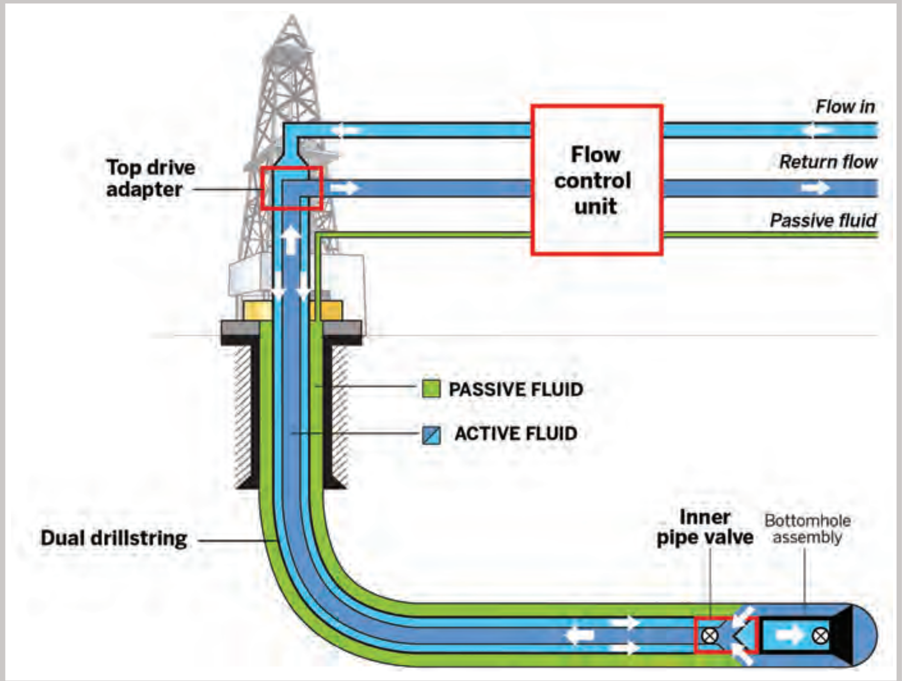
However, the newest developments are in the area of vibration management. "If you avoid vibration, generally the bit will hold up," Hutchison says. "When you download the report and see what has been happening with the vibration, you realize that the bottomhole tools don't fail; we beat them to death.

"We're almost to the point where we can run vibration sensors all the way along the drillstring," he continues. "Then you can see the different harmonics if you have vibration. It explains strange wear patterns and why we've damaged the bit. If you don't have your BHA (bottomhole assembly) stabilized and the bit face is vibrating, it drills an over-gauge hole, and you don't have the same directional control."

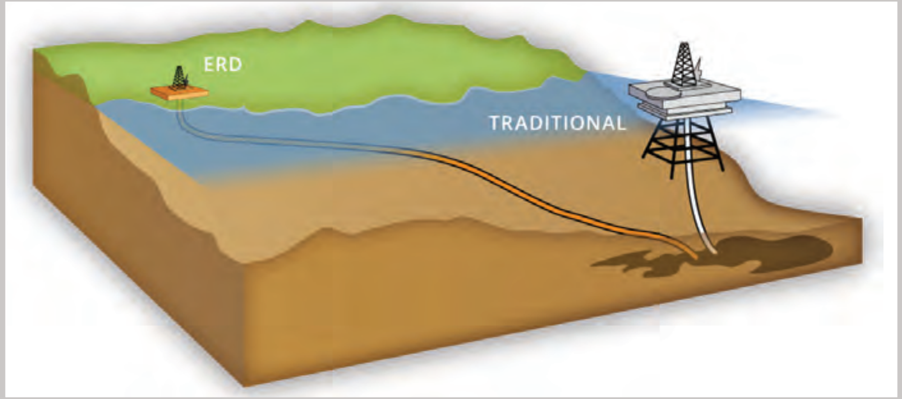
TDTECH, a New Zealand company, has the next generation of stabilizers and centralizers, according to Hutchison. The company offers mold-on drilling stabilizers and casing centralizers that are less expensive because these are simpler than previous mold-on centralizers.

"Previous polymer casing centralizers were slip-on type while polymer drilling stabilizers used a combination of materials, including steel, aluminum and fasteners to hold the tools in place. Our tools are a single piece, rather benign, high-grade polymer with zero metal parts," says Geoff Murray, general manager, TDTECH.

Its Archimedes Screw pumping effect helps reduce equivalent circulating density (ECD). Drillstring rotation revolves the screw elements, thereby pumping



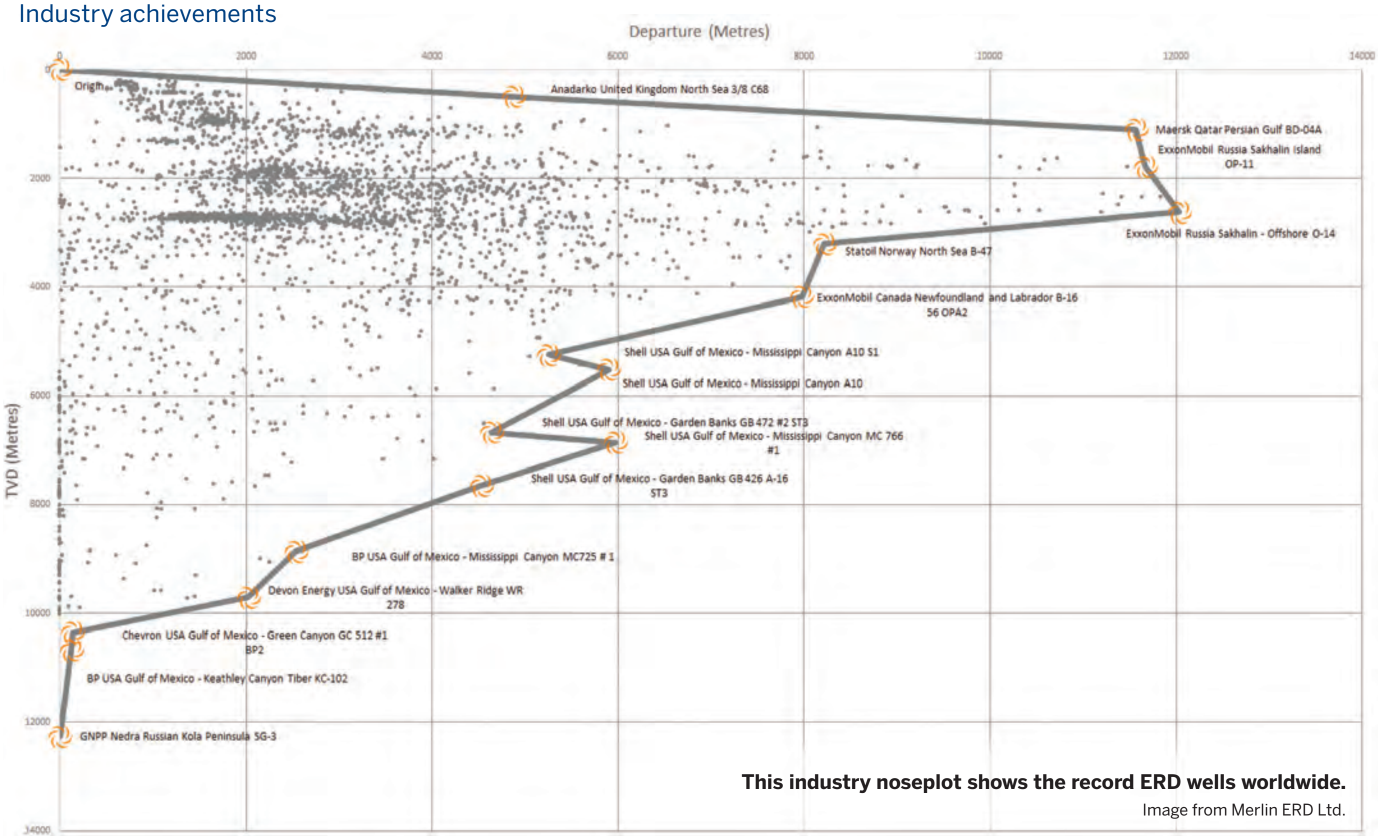
The Reelwell Drilling Method is a closed-loop drilling system that uses a dual drillstring. The annulus between the dual drillstring and the wellbore remains static and is free of drill cuttings. Image from Reelwell.



With ERD operators have drilled over 40,000ft offshore from a land drilling location. ExxonMobil's ERD has used the technology to reduce the need for offshore platforms. Image from Merlin ERD Ltd.

Extended reach drilling

Industry achievements



This industry noseplot shows the record ERD wells worldwide.
Image from Merlin ERD Ltd.

the drilling mud and reducing ECD. Another means for reducing ECD is via better hole cleaning, wherein less cuttings in the hole equate to less pressure drop, Murray explains.

Its Python Polymer Rotating drilling centralizer/stabilizer provides 60% to 95% wear reduction along with more than 50% torque and drag reduction, which might enable use of smaller drillpipe. The wear reduction results of the slippery, fiber-reinforced polymer exhibits a fraction of the abrasive wear of metal-on-metal contact, he continues. It also reduces stick/slip and associated vibration.

Hutchison also mentions a different kind of stabilizer called a Switchblade from ED Projects in the Netherlands. "They've got this Switchblade stabilizer that helps the vibration like any stabilizer, but it's got a really peculiar blade set. A huge issue is that stabilizers get balled up in the shallower, softer formations. This stabilizer, with its hydrodynamic design with enhanced flow-by area, can help if there is a clay-balling problem," he says. The hydrodynamic design also helps with tripping by tackling the root cause of pack off, which minimizes wall cake damage when both tripping and backreaming.

According to ED Projects, better drilling fluid displacement reduces the risk of swabbing and surging, which are key causes of wellbore instability. The tool profile and monoblade orientation reduces torque, drag and torsional vibration, which are key causes of borehole enlargement and subsequent BHA component failure.

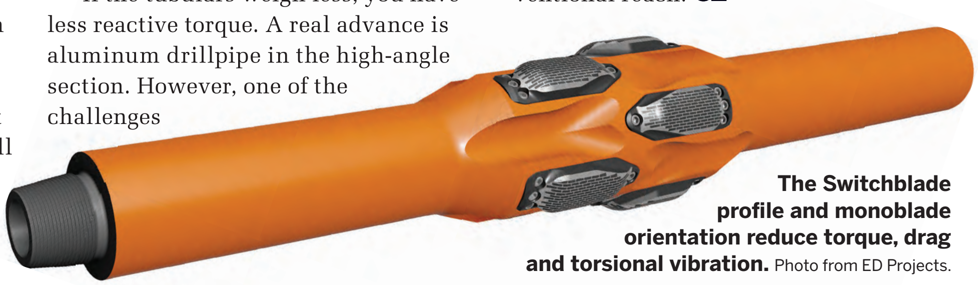
There are also improvements in tractor technology and intelligent completions, Hutchison notes. "It is often not the drilling; it is the completion or the well service that is the problem. Drilling is the easy part." The really clever solution is how you complete the well, and then how you service the completion if you have a problem.

Companies are doing everything they can to lower drillpipe weight. There are two approaches to this. The lubricity of the drilling fluid is one approach, but there are only small gains to be made using drilling fluids. The second approach is using lighter tubulars.

"If the tubulars weigh less, you have less reactive torque. A real advance is aluminum drillpipe in the high-angle section. However, one of the challenges with aluminum drillpipe is the connections, which are generally made of steel. The body is quite soft so it wears. The TDTECH mold-on centralizers can be attached to the aluminum drillpipe to reduce the wear," he explains.

Another technology undergoing development is the Reelwell drilling method (RDM). A trial was performed as part of a joint industry project on ERD wells (called ERD 20km+) by Norwegian company Reelwell, supported by The Research Council of Norway, operators Total, Petrobras and DEA, and Halliburton.

The RDM is a closed-loop drilling system using a dual drillstring. Clean drilling fluid flows down its annulus while mud and cuttings return to the surface through the inner string. The hole is free of cuttings, and the drilling technique reduces torque and drag while enabling wellbores beyond conventional reach. **OE**



The Switchblade profile and monoblade orientation reduce torque, drag and torsional vibration. Photo from ED Projects.

The lifting business

Audrey Leon chats with Schlumberger, Baker Hughes and Weatherford to learn about the latest technologies available for artificial lift.

OE: What's your latest innovation/ product in artificial lift technology? Please explain the technology and how it works.

Dedicated Schlumberger surveillance engineers monitor alarms to prevent or mitigate adverse events, diagnose probable causes, and recommend remediation measures—all in real time. Image from Schlumberger.

Optimizing wells through monitoring and surveillance is proven to minimize downtime, maximize production, and reduce total operating cost. Image from Schlumberger.

Khaled Elsheikh, vice president of marketing and technology, Schlumberger Artificial Lift Solutions: The industry is moving to a digitally enhanced age where it is critical to pair equipment with data collection and precise interpretation to expand well performance. The Lift IQ production lifecycle management service is the premiere monitoring and surveillance platform for optimizing artificial lift systems. From monitoring hardware in a single well to optimizing equipment and operations across an entire field, customers can choose the level of service to suit their needs. The Lift IQ service taps into the renowned engineering, manufacturing and surveillance expertise of Schlumberger with access to global service centers 24/7/365.

Monitoring and surveillance minimize downtime, maximize production, and reduce total operating cost. Once considered only for high-value offshore wells, the Lift IQ service is increasingly important for achieving economic targets in large brownfields, especially where wells are widely dispersed or where in-person troubleshooting expertise is limited. Data is transferred via satellite or cellular connections to and from remote locations, hostile environments, and sites with limited or no data acquisition capabilities. Schlumberger Artificial Lift Surveillance Center engineers use the data to correct discrete problems, update pump regimes to match fluctuating conditions, or identify underperforming wells that could benefit from further pump optimization.

The Lift IQ service provides access to all critical wellsite data in one cohesive, solutions-based software platform. It seamlessly merges data for quick and easy management of all monitoring and troubleshooting requirements: well and field performance indicators; alarms and events management; and diagnostics and optimization.

Nathan Holland, product line director, Artificial Lift Systems, Baker Hughes: Baker Hughes recently launched the TransCoil rigless-deployed electrical submersible pumping (ESP) system. The TransCoil system – developed in participation with Saudi Aramco – features an inverted ESP system with the motor connected directly to a new, proprietary power cable configuration, eliminating the traditional ESP power cable-to-motor connection. This improves overall system reliability. Unlike wireline-deployed ESPs, the fully retrievable TransCoil system does not have an in-well wet connection, which requires a rig to pull and replace it if the wet connection fails.

The power cable design enhances the reliability of the deployment string compared to coiled tubing-deployed ESPs that simply pull the power cable through the coiled tubing. The TransCoil system cable design also extends the operating range to 12,000ft compared to traditional coiled tubing-deployed ESP systems, which are limited to approximately 7000ft because, at greater depths, the weight of the power cable will cause it to collapse inside the coiled tubing, creating an electrical failure.

Steven Seale, global director, artificial lift software and automation hardware, Weatherford: Weatherford has introduced the WellPilot ONE – a life-of-well controller. A well typically comes online flowing before moving to artificial lift. With our new life-of-well controller, operators are able to use the same hardware and software license as the well transitions to each phase. This gives operators greater freedom to shift to the optimal form of lift at the right time without worrying about changing monitoring platforms.

In the market today, we are starting to see operators in the shale plays move to gas lift earlier on in the cycle, in part because of advances in gas-lift technology. These new technologies reduce capital equipment expenses and increase cost savings. WellPilot ONE enhances these savings by enabling operators to manage injection gas use, and optimize the performance curve of the well. The system informs your decision making so you can inject just enough gas to get the oil lifted. Any extra gas can then be sold.

The system works with both intermittent gas lift and continuous gas lift systems. We have a couple of control algorithms that have been very effective for operators in south Texas and the shale plays.

The same technology applies to an offshore environment such as the Gulf of Mexico or the North Sea, where gas lift is used frequently. Gas lift is one of the predominate lift technologies in an offshore platform environment. It's very common.

Of course, one of the benefits of the WellPilot ONE controller is that you can use it for many different lift applications. This enables you to continue with the same controller across all forms of lift needed for the life of the well.

OE: Where do you see artificial lift technology going in the future?

Khaled Elsheikh: Three key technology advances are occurring in artificial lift.

TransCoil RIgless Deployed ESP System
Image from Baker Hughes.

First, is the digital era of artificial lift. The progression of artificial lift is twofold: the advancement of equipment functionality running in parallel with gathering and interpreting data metrics for well optimization. Adding sensors and measurements is the first step to run-life improvements; however, analyzing and interpreting this data is critical for enhanced well performance. This next generation of artificial lift closes the loop to achieve a holistic approach to run-life. Providers must configure all aspects of digital innovation including connectivity, data security and transmission, automation, custom calibration, interpretation, and response speed—all in real-time. The end game is to avoid shutdowns and prevent failures with automated feedback control, which leverages machine learning, robust analytics, and engineering expertise to optimize well operations.

Secondly, alternative deployment technology is a key area of development for the industry and all service companies are introducing some great innovations in this area. ESPs are often selected as an optimal artificial lift method; however, conventional ESPs are run on heavy jointed tubing, which frequently requires a rig or hoist for maintenance and failures. These interventions defer production, increase costs, and delay operations. One example of alternative deployment technology is the ZEiTECS Shuttle rigless ESP replacement system, which "shuttles" standard ESPs through tubing on wireline, coiled tubing, or sucker rods without a rig or hoist. This technology minimizes production deferment, operating costs, HSE risks, and disruptions to operations. Moving forward, new technology in alternative deployment will further advance artificial lift wells by simplifying preventive maintenance and lifecycle management in changing reservoir conditions.

Thirdly, managing the production lifecycle is critical to overall well success. Operators change from one lift methodology to another throughout the well's life. It is beneficial to make these transitions as seamless as possible, ensuring timely changes and choosing the best technology for well optimization. Companies utilizing the full suite of artificial lift will benefit directly from the industry moving toward a comprehensive approach to enrich well life.

WellPilot ONE, closed (left) and open (right). Images from Weatherford.

Nathan Holland: In the current "lower for longer" crude oil pricing environment, it is more important than ever that operators get the most out of existing assets where the cost of development has already been absorbed.

Artificial lift is an important part of improving recovery from existing fields or accessing stranded reserves in satellite fields that can produce back to existing production facilities.

Based on these market drivers, technology development is centered around three primary areas of focus: alternative deployment methods to drive down intervention costs; smaller diameter systems that can be installed and retrieved through the production tubing; and long-life systems.

Recovery factors from offshore fields are much lower than onshore fields and artificial lift methods used most often in offshore fields are not the ideal solution to improve the recovery factor. ESP systems more effectively draw down the reservoir pressure to release additional hydrocarbons and improve reserve recovery, but the high cost of intervention to install and retrieve ESPs in offshore wells limits the use of this technology. Therefore, a major initiative by the industry is to develop new technology innovations designed to extend the life of the ESP and to reduce the cost of deployment by eliminating the need for a rig. In mature fields, being able to install artificial lift systems through the existing tubing is critical to minimizing costs. But, that requires smaller diameter equipment that fits inside the tubing and can handle the production rates typically found in offshore wells.

Baker Hughes Artificial Lift Systems is continually communicating with operators to determine the most critical technology innovations to meet the future production needs of the industry.

TransCoil is a good example of technology innovations geared toward meeting these industry challenges. By eliminating the need for a rig, operators can lower the cost of installing and retrieving ESP systems. And, by eliminating in-well wet electrical connections the system offers greater reliability vs. other alternative deployment options.

Steven Seale: Weatherford is working to harness the Internet of Things (IoT), or in our case the Industrial Internet of Things (IIoT) and specifically Edge Analytics.

If you look at IIoT – most of the discussion is focused on cloud computing. There's a lot of terminology and hype around moving everything into the cloud and applying analytics, but if you look at large IT companies, they are pushing the Edge. When we talk about the Edge, we mean the edge of the network, which is where the WellPilot ONE operates today.

To give a general example of how the Edge differs from the cloud: there are refrigerators now that can tell you when you need to buy milk. The fridge in this case has Edge technology built into it. Information from the fridge can flow up into the cloud and an online retailer can enable you to make a decision to buy the milk and have it delivered.

In the oilfield, those Edge devices are at the well. The WellPilot ONE is known as an Edge device because it is at the well site. And a lot of intelligence and analytics are taking place at the well site using sophisticated control techniques on our Edge devices. The data and analytics from the well site would make their way into the cloud through Edge devices.

When operators run a SCADA system, it gathers information from Edge devices—which are simply known as controllers or RTUs (remote terminal unit) in today's world—and that information flows into your master data repository, your data historian, which is essentially in the cloud.

This is important because in the oilfield space, the RTU or controller is at a well site and the central database system and IT infrastructure is, for the most part, at the central headquarters.

For example, any alarms that we use today flow from the system at the wellsite into the central headquarters where you typically have a team of people monitoring the field.

As we continue forward and more computing power is available in the market with Edge devices like the WellPilot ONE, better decisions can be made closer to the well and the assets. OE

Glen Lyon **sets sail from South Korea.** Image from BP.

Faster start-up

Ronnie Bains, of Emerson Process Management, explains how the use of dynamic simulations and operator training systems can support engineering and workforce training to help bring offshore assets online quicker.

For any new offshore project there is the requirement to bring the asset online safely and as quickly as possible. Reduced engineering, commissioning and start-up periods directly affect when an asset can reach nameplate capacity. Making reductions to project schedules, while extending the level of design integrity, innovation and design quality, presents a difficult challenge.

Dynamic simulation can play a key role in helping to meet these challenges. Having evolved and become more accessible over recent years, the technology can be applied to a growing range of process industry applications. For the process industry, including offshore oil and gas, dynamic simulation solutions comprise of an integrated control and safety system (ICSS) communicating with a model of the process facility, which is designed to reflect actual plant process dynamics and to provide realistic feedback for the ICSS.

The human machine interface (HMI) and control logic will be a replica of what the operator would see in the real control room, creating an environment where an experienced operator would not be able to tell the difference between the real plant and the simulated plant.

Life cycle of a project

Dynamic simulation solutions can be used throughout the lifecycle of a project, from an initial standalone process model built to perform verification studies of process and control system design, to commissioning and operating procedure verification, or "virtual commissioning," and training, the traditional use of dynamic simulation.

In the initial design phase, the process model can be integrated with the control system configuration at various stages during the ICSS development. That allows it to be used as a tool to provide enhanced verification of the ICSS configuration, in addition to the traditional acceptance testing. This can include verifying alarm and trip settings, providing initial controller tuning values and enhanced verification of control logic. As more data becomes available, the dynamic simulation of the process can evolve and support different activities through the typical phases of a project.

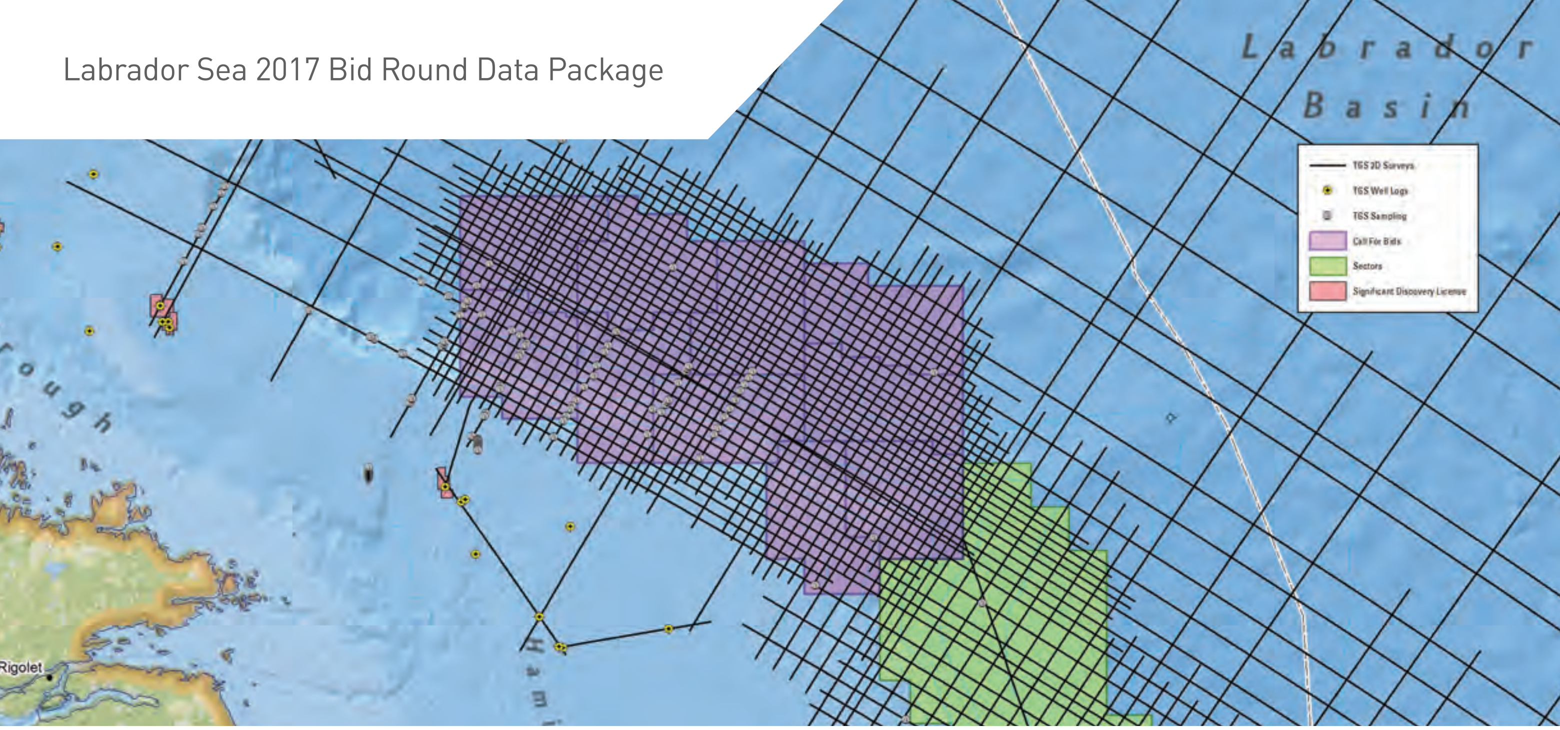
In commissioning phases, dynamic simulation can do "virtual commissioning," where issues that would otherwise be highlighted during commissioning can be identified and addressed prior to commissioning.

Training

Operators are usually required to be certified to ensure that they meet company standards for competence. Operator training solutions (OTS) are increasingly used to support this, but realistic dynamic process simulation and operating scenarios are key to their effectiveness.

OTS consists of a software-based representation of the dynamic and behavior of a process, residing on dedicated computer hardware and are usually integrated with a replica of the ICSS. OTS enables operations personnel to gain experience in an offline, non-intrusive environment, and expose them to what they will experience in their actual control room. Operators learn

Labrador Sea 2017 Bid Round Data Package



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When you have unlimited insight into Labrador Sea you have unbeatable advantages.

TGS is pleased to offer a comprehensive data package including over 20,191 km of seismic, gravity, interpretation and well data covering the NL01-LS Sector area in preparation for the upcoming East Coast Canada bid round. This dataset of newly acquired and older vintage data is currently undergoing pre-stack time and depth reprocessing, incorporating unsurpassed flow with enhanced multiple suppression, prestack time and depth migrations with AVO compliance through the entire flow.

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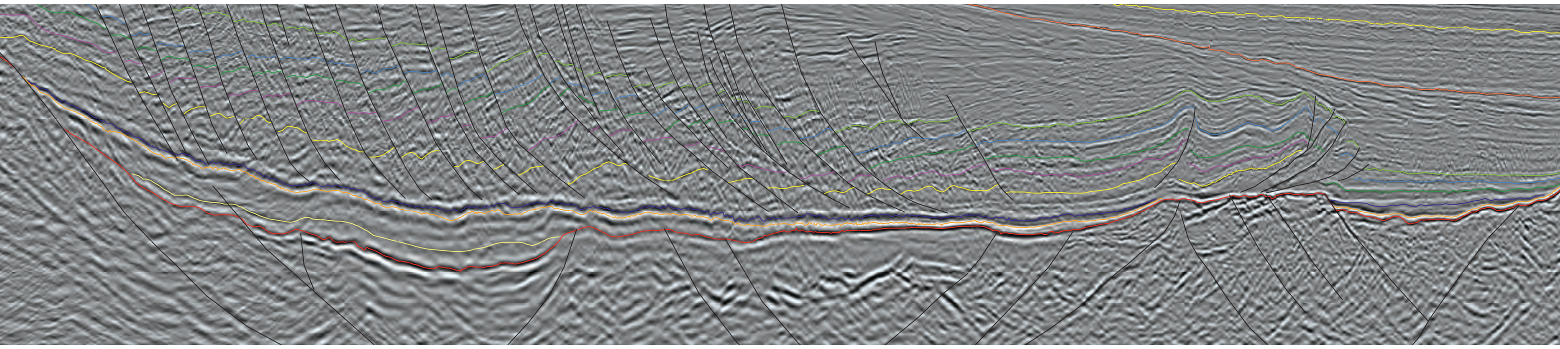


Labrador Sea 2D Reprocessed

See the energy at **TGS.com**

BP's *Glen Lyon* FPSO, moored west of Shetland.
Image from BP.

about control and safety system operating concepts, while gaining experience of their actual process in preparation to effectively handle incidents, process upsets, and the management of abnormal situations.

Training on a process-specific training platform raises skills levels, leading to faster and smoother start-ups, less downtime, less off-spec products, less supervision and increased energy efficiency. An American Petroleum Institute study found there was a US$350,000/year per operator positive financial impact when an operator was upskilled from an average level to an advance level.

Improved operator effectiveness also leads to increased plant-wide safety. Dynamic simulation can also replicate very unusual situations with transients, such as start-ups and shutdowns, that operators may rarely otherwise experience.

How does it work in practice? The following examples demonstrate how dynamic simulation has supported the engineering phase of two BP projects to reduce commissioning time and how an OTS was used for operator training and competency assessment, so that operators were better prepared and able to minimize production trips.

Glen Lyon

An OTS with dynamic simulation is currently supporting the *Glen Lyon* floating production, storage and offloading (FPSO) deployment. The *Glen Lyon* FPSO will be installed in the West of

Schiehallion was discovered in 1993, and Loyal a year later, with production starting in 1998 from the *Schiehallion* FPSO, which the *Glen Lyon* will replace. Schiehallion and Loyal together had more than a billion barrels in place and recovery to date had been about 15%.

As a result of the redevelopment, which could include polymer enhanced oil recovery, BP hopes it can maximize recovery to above 30% and extend production out to at least 2035.

The *Glen Lyon* FPSO was constructed at Hyundai Heavy Industries shipyard in Ulsan, South Korea, over a four-year period, amounting to some 21 million hours.

Shetland, replacing the *Schiehallion* FPSO, as part of a redevelopment of the Schiehallion and Loyal fields. At 270m-long and 52m-wide, the unit, which arrived on station in June of last year, with start-up expected this year, is one of the largest FPSOs in the North Sea.

A high fidelity dynamic simulation was developed by Emerson to support a number of activities including engineering and training.

Emerson is providing a fully operational training replica of the *Glen Lyon* project, in BP's Aberdeen offices, prior to start-up. Training provided by the OTS could help BP personnel achieve safe, efficient operations and take full advantage of the ICSS that Emerson is providing for the new vessel. The OTS includes a virtualized DeltaV system that will control production, and a DeltaV SIS process safety system for process and emergency shutdowns. Personnel will learn both DeltaV operating concepts and the actual process, preparing operators to effectively handle abnormal situations and process upsets, as well as providing decision support.

Before the dynamic simulation/process model was developed and the complete multi-unit OTS delivered, Emerson provided BP with a simple separate standalone unit without dynamic simulation. This was used to evaluate graphics, provide HMI familiarization and support pre-tow training and ICSS engineering.

The standalone unit was based in Aberdeen, but networked to allow remote access by operators located throughout the UK and also in Korea, where the FPSO was being built. This enabled a larger group of BP operating technicians to carry out training, evaluation and competency assessment.

It is anticipated that the dynamic simulation will provide future benefits for BP in *Glen Lyon*'s project stage as well as ongoing operations. **OE**

***Ronnie Bains** is the dynamic simulation and process optimization business manager at Emerson. Bains has an Executive MBA from the University of Leicester Business School and a bachelor's in chemical engineering from Loughborough University.*

OE REGION

MEXICO

Mexico poised for growth

Pushing forward

Mexico's energy reform has weathered both the storms of public scrutiny as well as the bad luck of launching during a global oil price downturn. Despite the challenges, Mexico has seen some modest success, but will it continue? Audrey Leon reports.

The first real test of Mexico's energy reform came in 2016 when the country carried out its first deepwater round, as well as selecting state-owned oil company Pemex's first farm-out partner. With a successful deepwater bid round under its belt, the country is poised for future growth, but many outside factors could influence where the industry goes from here.

In 2013, Mexico's President Enrique Peña Nieto and his political party PRI (Institutional Revolutionary Party) presided over an ambitious plan, teaming up with political rivals, including the center-right PAN (National Action Party), to secure enough votes in the country's legislature to open Mexico's oil and gas industry to private and foreign investment for the first time in seven decades.

In 2015, Mexican officials learned much from a disappointing Round One (in which only two of 14 areas were awarded), choosing to incorporate feedback from the oil and gas industry in order to make future rounds more attractive.

"The Mexican hydrocarbon authorities managed to tailor terms to what interested companies deemed encouraging, such as the minimum working program commitment and the size of the blocks," says Adrian Lara, GlobalData's senior upstream analyst covering the Americas.

"The exploratory terms offered are attractive based on the relatively large size of the areas and on their minimum work program," he continues. "The exploration contract establishes the working program on a system of committed points that make it possible for the operator not to drill a single well in the first four-year exploration period, if these points are accumulated in other ways such as seismic acquisition."

Local content

Last March, in preparation for December 2016's deepwater round (1.4), Mexico's Ministry of Economy lowered the local content requirements for deepwater leases. The rule, announced in Mexico's official journal of the federation, requires oil and gas companies to use 8% local content in deep and ultra-deep waters by 2025.

December's long-awaited Round 1.4 was broadcast live over the internet (like the

Pemex's Abkatun A Permanente platform. Photo from Pemex's Flickr.

Inside

previous three), reflecting the country's desire for transparency. The round was largely a success with eight of 10 blocks awarded. The round offered four blocks in the much-coveted Perdido Fold Belt, covering 8218sq km, about 320km south of Texas, and 250km from Matamoros, Mexico.

The round's success, in a way, also proved that Mexico's regulators ultimately made the right call on their bid round strategy.

"To some extent [the success] allows the Mexican authorities [to believe] that they were right to be a bit slower than others had expected in auctioning these areas because they had to learn a little bit first," says Francisco J. Monaldi, a fellow in Latin American Energy Policy for the Baker Institute at Rice University. "They significantly learned and adopted recommendations offered by the companies. Overall, they should be, and are, very happy."

Perdido

The Perdido Fold Belt is of obvious interest to deepwater players, as it has been developed and studied from the US side of the transboundary line, and currently supermajor Shell operates there. In the 2016 Mexico Offshore Supplement, we reported that the deepwater Gulf of Mexico basin, including the Perdido Fold Belt, contains the greatest amount of undiscovered resources with of approximately 27.1 billion boe.

The big surprise of the ceremony was China National Offshore Oil Corp. (CNOOC) winning two blocks in the Perdido area; Blocks 1 and 4. Block 1 covers 1678sq km in 2515m water depth, and is estimated to hold 458 MMboe of super light oil resource. Block 4 covers 1877sq km in 1264m water depth, and is estimated to hold 408 MMboe resource.

While CNOOC has deepwater experience, its entry into Mexico's deepwater sector has interesting geopolitical implications, Monaldi says. "CNOOC is geopolitically and strategically very interesting for the Mexicans," he says. "After Donald Trump's presidential election victory (in the US), the Mexican government is trying to improve its relationship with China.

"The relationship (with China) was relatively bad as [Mexico] saw them as a competitor. I do think that now the priorities have changed. And [Mexico] would like to hedge a bit, now that the US is opening a new era of not so friendly relations with Mexico," he says.

Other winners in the Perdido Fold Belt were a consortium of Total and ExxonMobil (Block 2), and a consortium of Chevron, Pemex and Inpex (Block 3).

Six blocks in the Salina basin, in the southeastern Gulf of Mexico, were also offered during the deepwater round. A consortium of Statoil, BP and Total won Blocks 1 and 3, while Blocks 2 and 6 received no bids. A consortium comprising Petronas subsidiary PC Carigali and Sierra Oil & Gas took Block 4, while a consortium of Murphy Oil, Ophir, and PC Carigali won Block 5.

Farm-out first

In addition to the deepwater round winners being chosen in December, Pemex's first-ever farm-out partner, BHP Billiton, was also chosen during a live ceremony for the deepwater Trion field. Following the deepwater round, Juan Carlos Zepeda, President Commissioner for Mexico's National Hydrocarbons Commission (CNH), said that production could start at Trion by 2023.

Pemex's farm-out process is a bit unusual. To gain a partner on a field, the company must go through a two-step process, says Jose Valera, Houston-based partner and co-head of law firm Mayer Brown's oil and gas practice. Due to Mexico's hydrocarbons law, Pemex must convert the assigned areas (assigned in Round Zero) into a contract, and select a partner through a competitive bid process, whereby regulators will choose the winner. "This is unusual and uncommon," Valera says. "Typically, even NOCs (national oil companies) are able to pick their own partners when an area is adjudicated to them, but the [Hydrocarbons] law is what it is."

SENER's Pedro Joaquín Coldwell, Mexican President Enrique Peña Nieto, and Pemex CEO José Antonio González Anaya. Photo from Pemex's Flickr.

Last November, Pemex rolled out its 2017-2021 business plan, where CEO José Antonio González Anaya presented the company's aggressive farm-out plan, which includes five more projects for 2017, including two offshore: the shallow water complexes Ayín-Batsil and Ayatsil-Tekel-Utsil, both within the Bay of Campeche off the states of Tabasco and Veracruz.

Monaldi calls the farm-out plan, "ambitious." "Clearly, [González] has a mandate," he says. "My perception is that he wanted to focus the cash flow of the company in the most profitable areas where Pemex already has production." Monaldi notes that in Round Zero, Pemex kept a lot of areas for itself, and if the firm doesn't invest in them, then it must return the fields to the government. "It's in [Pemex's] best interest to partner, rather than wait," he adds.

González has a reason to embrace an agressive farm-out strategy. President Peña Nieto replaced his predecessor Emilio Lozoya Austin in February 2016 for not moving fast enough to complete the partnerships necessary to help curb Pemex's declining production numbers.

And, Pemex needs these farm-outs to be successful. "Clearly Pemex needs partners, not just for exploration and production, but for other assets, such as refinery assets, etc.," Valera adds. "It behooves them to be a good company to work with. The financial plan of the company to reduce expenditures hinges on passing on costs and capital investments to partners. [Pemex] needs to be good a partner."

Political implications

President Peña Nieto staked his legacy on the success of the country's energy reform, but while it was a remarkable success in getting political adversaries to come together to pass changes to Mexico's constitution, the speed of the roll out coupled with some missteps may tarnish that reputation.

The public's perception of the energy reform is not overwhelming positive, especially due to the government roll-out of higher domestic gasoline prices in early January this year, which led to riots and protests.

"The recent riots and protests because of the gasoline price, will significantly damage the reputation of the energy reform," Monaldi says. "Because for consumers, all this is abstract. The other thing they see is that production continues to decline. There is frustration that Mexico is soon to have a negative balance of payment in liquid hydrocarbons." He adds: "For the wider public, this is not going to be a winning issue."

And for those reasons, Monaldi believes it is unlikely Peña Nieto's PRI will win the next presidential election in 2018. Currently, leftist candidate Andrés Manuel López Obrador (of the MORENA party) is ahead in polls in the country. López Obrador, a former mayor of Mexico City, first ran for president in 2006, losing to PAN candidate Felipe Calderón. He then ran again in 2012, losing to Peña Nieto. When he runs again in 2018, López Obrador will face former president Calderón's wife Margarita Zavala (PAN), current Mexico City Mayor Miguel Angel Mancera (PRD), and Peña Nieto's current Secretary of the Interior Miguel Angel Osorio Chong (PRI).

In a 31 January poll published by *El Financiero*, López Obrador polled 6% over Zavala with 33% of the polled voters saying if the election was held then, they would vote for the leftist candidate. And any failure related to implementation of the energy reform could give López Obrador a political flag, Monaldi says. And if he wins, the leftist candidate could decide to appoint officials who will slow future efforts related to the reform.

So what does the price of gasoline have to do with upstream? Monaldi says the gasoline prices not only creates tension with the general public with respect to the reform, but it affects Pemex in the end.

"Depending on how things play out, it might have some negative implications (i.e. people asking for heads to roll)," Monaldi says. "On the other hand, it is important that they do the downstream opening, even for upstream, because if Pemex continues to be the only supplier of refined products in the market, Pemex cannot use more of its cash flow to roll into upstream. That could create bigger cash problems, and produce more farm-outs. It's a problem if Pemex is in bad shape."

The future

We're starting to see some movement from winners of the second shallow water round. In September 2015, during Round 1.2, Italian explorer Eni won Block 1, which includes the Amoca, Miztón and Tecoalli oil fields. Last year, CNH approved Eni's plans to drill the Amoca 2 well, which was scheduled to begin in December and end in March 2017.

"These three fields (Amoca, Mitzon and Teocalli) were highly valued given their nearness to shore, the shallow depth and the amount of estimated resources," Lara says, adding that Eni is also interested in participating in the upcoming round 2.1, which is set for 19 June.

Round 2.1 will offer 15 shallow water areas in the Gulf of Mexico in Tampico-Misantla, Veracruz and Cuencas del Sureste Basins. ■

Engineering for Mexico's deepwater developments

Fernando C. Hernandez, of SECC Oil & Gas, and Efrain Rodriguez, of IMP, discuss efforts to research rigless production solutions for Mexican deepwater operations.

Mexico's December 2016 Round 1.4 ushered in a new era for Mexico's deepwater industry, with unprecedented commitments from international oil companies (IOCs).

The infusion of international technology will be key to Mexico's success in unlocking deepwater developments. Mexico's proximity to the US will support this quantum leap into deepwater, due to the supply chain, intellectual capital, and the workforce experienced in managing and delivering deepwater projects for many of the IOCs, who will now be expanding into Mexico.

Instituto Mexicano del Petroleo (IMP), a public research organization, has carried out extensive preparatory work to develop Mexico's deepwater fields, years before the blocks were awarded to the IOCs, leveraging over 50 years of experience. In the last 30 years, IMP has provided state oil firm Pemex with technological support for the planning and development of offshore fields. Moreover, IMP's researchers, complemented with SECC Oil & Gas' global subsea experience, set out with the following objectives: (1) Increasing the feasibility of having future deepwater fields in Mexico produce optimally at first oil; (2) to enhance fields by incorporating and centralizing global lessons learned and best industry practices; (3) to reduce the reactionary and unplanned interventions that are common with deepwater fields

Rigless production

A key emphasis, from IMP's researchers and SECC's engineering and technical group, has been on introducing rigless production systems. This method was borne out of a step-change maneuver of pre-installing SECC's female connectors on subsea manifolds in the North Sea. This, in turn, allows all wells linked to a manifold to be stimulated and intervened on, via single access point, by way of a DP (dynamically positioned) vessel. Rigless production differs from rigless interventions, as intervention equipment is bypassed altogether, and operations focus on an entire subsea production scheme, instead of just Xmas trees.

Figure 1: SECC's connector installed on a manifold. Images from SECC.

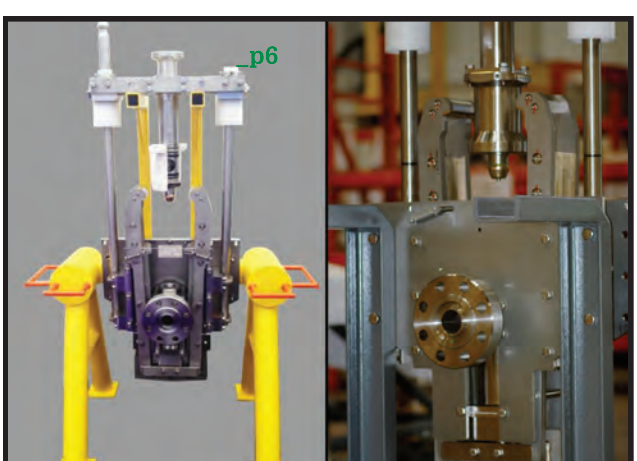


Figure 2: A view of the connector's inner workings.

Operationally, once a manifold is installed subsea, a rigless male connector is deployed from a DP2+ vessel—via an open water downline, and mated with the corresponding female on a manifold, allowing for well stimulations to be carried out to the tune of 16-56 bbl/min, at 15,000psi. This methodology highly benefits deepwater developments, as it allows for the following:

- Stimulating horizontal (and vertical) trees without removing crown plugs.
- A vessel no longer has to test, deploy and recover equipment multiple times for different wells during an intervention campaign.
- The access point can equally be utilized to inject chemicals throughout an entire field, and export lines, to support flow assurance operations, and deter hydrates and asphaltene blockages.

Furthermore, should an operator opt to not install a connector at the build stage, a spare hub can be used to land seabed-based equipment. This is accomplished by mating a modified jumper—to a hub on a manifold—which ties in into a female SECC connector—reference Figure 3. Safety wise, SECC's connectors allow for a vessel to connect and disconnect, with zero spills during normal operations. Should a DP2 vessel have a drift off, requiring an emergency disconnect, the connector solely requires tension or pull from the downline to disconnect. Upon this occurring, the connector instantaneously seals at both the male and female end, ensuring that the downline, and the well, are secured.

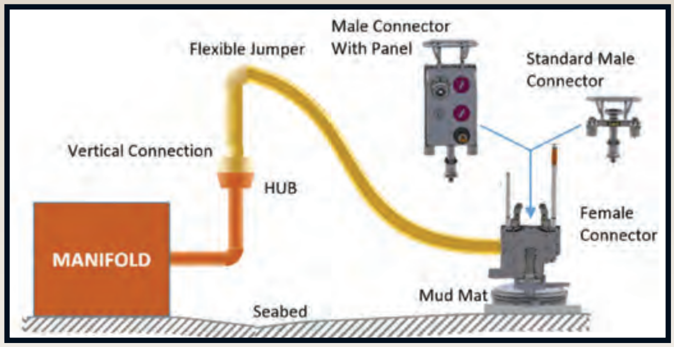


Figure 3: The retrofit approach, which allows a connector to enhance a field

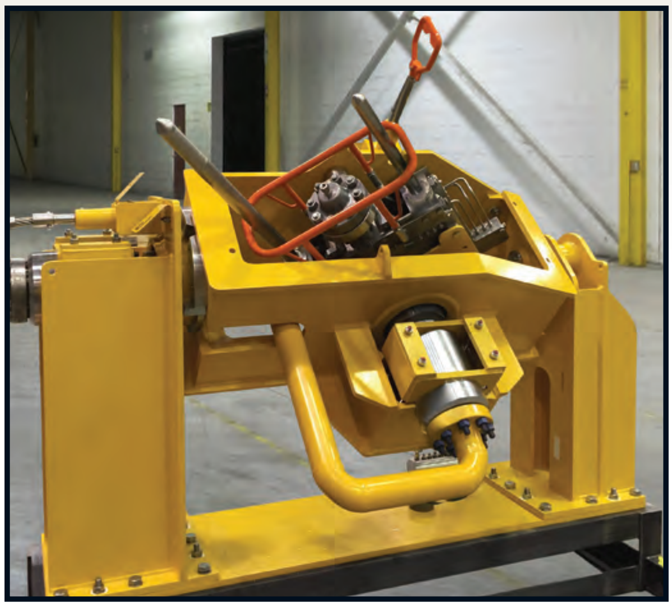


Figure 4: SECC's seabed based equipment, with gimbaling and swiveling capabilities, for retrofit operations

Intelligent access points and hydrates

Because deepwater temperatures are inseparably linked with hydrate formation, the international venture analyzed fields where production was disrupted due to blockages, or where hydrates indefinitely blocked an export line. IMP and SECC realized that key access points were not always accounted for – to inject chemicals to disassociate/remediate hydrates – instead an improvisation philosophy was used to find/create entry points.

The aforementioned improvisation demonstrated the effectiveness of the rigless production method in proactively creating intelligent access points at the build stage, or via the retrofit option, on manifolds. Furthermore, such points can also be created on pipeline end manifolds (PLEMs), to further target hydrates throughout a field lifetime.

There are, however, limitations to improvisation. In a scenario where a API 17H hot stab is the only means of injecting chemicals into a field, the stab severely restricts injection flow rates. Furthermore, if the access point is located on a PLEM that is kilometers away from the blockage near a manifold, the chemicals success is limited, as it comingles with a pipeline's content, diluting a chemical's effectiveness.

Reactive access points

Alternatively, dedicated injection points can become blocked, requiring alterations to the subsea architecture. This is highlighted by pulling a jumper from a manifold, to create an access point, to enable a bespoke intervention panel with a hot stab entry point—for chemical injections—to be installed. This is common when an export line is completely blocked. Moreover, the bespoke panel must be designed, built, and tested, before it is deployed subsea: all of which delays hydrate remediation efforts.

Alternatively, when an export line isn't blocked, but half of the flowlines that connect to a manifold are blocked, a jumper is also pulled, to create an entry point (jumpers with blockages cannot be pulled, as the hydrocarbons cannot be flushed). The drawback is that a producing well is now offline as the jumper linked to it has been pulled.

Importance of depressurization

IMP and SECC equally concluded that access points need to equally enable remotely operated vehicles (ROVs), and subsea depressurization/remediation equipment, to remove blockages via a vacuum. Depressurization is paramount, as chemical injections doesn't guarantee the removal of obstructions. Furthermore, SECC's male connectors are designed to accept a male intervention panel, enabling ROVs to swiftly mate the male connector, without a downline, onto a manifold to depressurize a subsea production scheme (See Figure 3).

Additionally, removing hydrates from a singular hot stab entry point on a subsea asset is to be avoided, as hydrates tend to reform in hydrate remediation equipment when removed. Thus, it is vital to outfit an intervention panel with ROV paddle valves and a hot stab, with a large bore, to remove hydrates at an efficient rate. A secondary hot stab is used to methodically inject chemicals—via the paddle valves—at the large bore stab. This allays hydrates from reforming as they exit, as they are dosed with chemicals, increasing the success rate of a remediation project. Failing to dose inevitably leads to additional downtime, as the subsea equipment must itself be cleared of hydrates before it can resume operations, which can occur multiple times.

Conclusion

IMP and SECC's collaborative work concluded that the following be accounted for in Mexico's imminent deepwater fields: (1) A minimum of one spare hub be available for two manifolds that connect to each other, or one spare hub if only one manifold is brought online; (2) that a manifold have access to all the flowlines and export lines (via intelligent valve arrangements) for flow assurance operations; (3) that said valve arrangement allows for well interventions to be carried out on all the wells linked to it. Furthermore, the creation of intelligent access points is not limited to manifolds, but it is to be equally applied to trees, as well as PLEM's, to increase the productivity of future fields. ■


Fernando C. Hernandez Hernandez is the subsea technical advisor at SECC. Hernandez speaks three languages and has extensive international experience in the ROV tooling, automated controls, subsea and well intervention sectors.


Efrain Rodriguez is an offshore field development project manager at IMP. He holds a PhD in mechanical engineering from University College London and has 30 years' experience in the offshore oil industry.

CGG sheds light on Mexico's seismic scene

Audrey Leon speaks with Karim Lassel, Director General, CGG México, to get the company's perspective on Mexico's geology, the energy reform, and much more.

CGG's sister vessels, the *Oceanic Sirius* and *Oceanic Vega*, are heading the five-vessel fleet currently acquiring Mexico's first offshore orthogonal wide-azimuth (WAZ) seismic program on behalf of Pemex. Photo from CGG.

OE: CGG has been in Mexico for nearly 30 years (established in 1988), can you tell me your thoughts on Mexico pre- and post- the energy reform. What was it like to come into the country and establish operations, and what is it like in this new environment working within the country? Is there a noticeable difference?

CGG will indeed be celebrating 30 years of presence in Mexico next year. From the outset, we've been committed to bringing our latest technology to the country to accompany Pemex in its exploration and production projects. This has put CGG in quite a unique position in terms of our in-depth local/regional understanding of the petroleum systems in Mexico and the Gulf and also in terms of our long-standing operational experience and relationship with Pemex, pre-energy reform. Since the beginning of the energy reform and throughout all the changes, CGG has adjusted its structure and business offering to address the new market and new requirements. For instance, CGG was among the first companies to propose multi-client projects and has been an early investor in this newly established Mexico business model.

Switching from a national oil company (NOC)-dominated market to an independent oil company (IOC)/NOC multi-client market in such a short time is a big change, especially when it takes place against the backdrop of a severe industry downturn globally. For the last two years, and this will probably be the case in 2017 too, operators have all been in a transition phase… a period of adjustment and change for some or a learning curve for others. However, although the depressed global market has led to a major slowdown in investment, we are seeing a high level of investment in Mexico as a result of the unique opportunities generated by the energy reform. Our Encontrado multi-client reprocessing project in the Perdido fold belt is a key example of this. The energy reform has also clearly given rise to a different, new level of competition where cost is often used as a key differentiator. We are meeting this challenge by optimizing the design of our solutions through smart integration of all the geological and geophysical data available and using the best technologies, in order to help jump-start industry understanding of the new opportunities available in Mexico and reduce cycle times.

OE: What resources have you brought with you to Mexico?

At the end of last year, Pemex awarded CGG a key contract to acquire and process Mexico's first offshore orthogonal wide-azimuth (WAZ) seismic program, which is specifically designed to optimize sub-salt seismic imaging in the geologically complex deepwaters of the Perdido area. We are therefore bringing a highly specialized fleet of five vessels into Mexico to acquire this new WAZ 3D data set. We are also teaming up the resources and capabilities of our Villahermosa and Houston subsurface imaging centers to deliver advanced processing of the newly acquired data combined with the data from an existing WAZ survey CGG acquired in the area in 2010.

The new WAZ survey, covering approximately 10,000sq km, will be acquired perpendicularly over the existing WAZ seismic data. The imaging of this first large-scale combined orthogonal WAZ data set is expected to provide significantly enhanced sub-salt imaging results due to the improved illumination of the targets beneath the complex salt canopy combined with our advanced subsurface imaging technology.

At this stage we are finalizing mobilization of the fleet of vessels we'll be deploying so that the survey can start in February; with the delivery of full production processing results in early 2018.

OE: What does the seismic scene look like in Mexico currently? What is your perspective on current activity off Mexico?

Seismic activity in Mexico remained at quite a high level during 2016 despite the global industry downturn although it wasn't as spectacular as we saw in 2015. In terms of multi-client activity, 18 or so companies are registered to acquire and/or process seismic data and, interestingly, the focus of this acquisition work was for 2D seismic, although

3D acquisition took a much larger share of overall multi-client spend. Among the 40 or so multi-client projects approved by CNH, CGG had six in total and is currently conducting one acquisition and one reprocessing project that should be completed by mid-2017. Considering that only Pemex is actively doing proprietary exploration, exclusive projects are rather limited. That being said, two tenders were awarded in 2016 and CGG won the challenging deepwater program mentioned earlier.

In my opinion, the multi-client seismic acquisition market will slow down slightly, pending the interest shown by the new IOCs that arrived in Mexico in December 2016, and its focus is also likely to shift from large 2D to acquiring smaller areas with higher resolution that can be mainly achieved with 3D.

OE: Could you tell me about some of the projects CGG is working on in Mexico?

The highlight of our multi-client data offshore Mexico is the Encontrado reprocessing. This involves the reprocessing of over 38,000sq km of legacy wide- and narrow-azimuth 3D data in the Perdido fold belt, linking this frontier region to our US data sets. An "Early-Out" RTM pre-stack depth migrated (PSDM) version of this merged dataset will be available in February. Nine surveys acquired with different orientations have been merged together to create a huge seamless data set. The intention is to turn this frontier area into a well-understood basin by using the latest technology to resolve large-scale complex geological challenges. The detailed regional PSDM volume will be suitable for both basin-scale exploration and potential prospect evaluation and will enable structures offshore Mexico and the US to be correlated to define an accurate interpretation of the area.

We are also currently acquiring 200,000 line-km of multi-client airborne gravity and magnetic data over six blocks off Mexico. The survey will provide coverage over the most prospective areas, from the prolific Perdido fold belt (Block 1) to the more mature near-shore heavy oil belt (Block 6). The data will help explorers map crystalline basement and magnetic and density anomalies from within the sedimentary section. The airborne survey will also collect continuous data through the "transition zone" from the marine environment to onshore.

A comprehensive interpretation, combining this new data set with available geologic and geophysical data, will also be undertaken by CGG's in-house interpretation team. Deliverables will include a full geophysical interpretation report, including definition of basement lithology and structure, mapping of sediment fairways and depositional-centers and any intrusives or salt which may be present in the sedimentary section. These will provide important insights to exploration and de-risking of prospective areas by oil companies.

Block 1 of the airborne gravity and magnetic multi-client data has been acquired, processed and delivered to the participants.

OE: What are some of the challenges CGG sees in the Mexico market (workforce, equipment, etc.), and what are some ways the company has worked to resolve them?

The industry has experienced some serious challenges during the last few years and Mexico has not been exempt from those. If we look at the challenges specific to the local market the obvious ones are operational security concerns in certain onshore areas and the shortage of foreign investment to execute the projects that are planned or needed.

The fast-changing Mexican market, as led by the energy reform's tempo, is also seen by some companies as introducing an element of uncertainty and therefore being seen as a challenge.

The key to addressing these challenges is to remain very attentive to any early signs of change and to be flexible so that we always maintain the right team in country with the technologies that are needed.

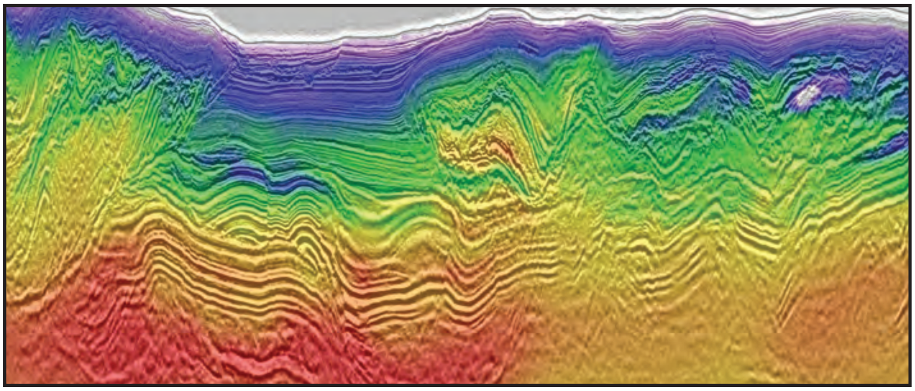
OE: As a company that has been present in Mexico for almost three decades, what is the long-term outlook for Mexico's oil and gas industry from your perspective?

Without any doubt, offshore Mexico currently offers the most interesting and promising unexplored and underexplored basins worldwide; by this I mean that, in terms of their potential for new discoveries, Mexico's waters are by far one of the most attractive areas on Earth today. This means that the growing industry interest in exploring these areas, as seen over the last three years, will very likely continue and probably grow further.

However, the "below ground" aspects are only half of the equation for exploration companies. The other aspects, that are certainly no less critical, are the "above ground" conditions, which include all the regulations, fiscal terms and overall working conditions that Mexico needs to consider to increase its attractiveness, particularly with respect to other countries that are also competing to attract investors. In this regard, one has to recognize that the Mexican authorities are very alert and active at comparing and adjusting, when and where necessary, to secure a leading position for the attractiveness of the Mexico brand.

In my opinion, we will continue to see many changes in the years to come and we will witness Mexico continuously striving to be a better place for investors. ■

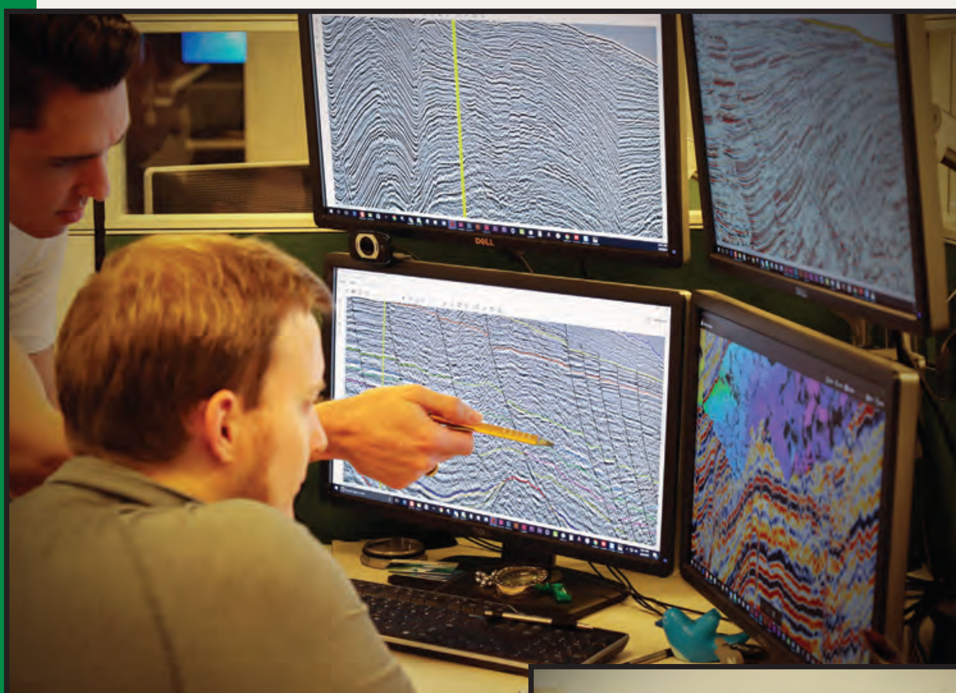
Karim Lassel is Director General of CGG México and has over 25 years' experience in the oil and gas industry. After joining CGG in 2012, he held various sales and marketing positions within its Land Acquisition business line before being appointed VP, Geomarket Director & Country Manager for Mexico, based in Mexico City. He spent 17 years working for Schlumberger, where he held various technical and managerial positions. Lassel has an engineering degree from the University of Science & Technology in Algiers and a Master's in Geotechniques from the Paris School of Mines and is an INSEAD Alumni.



Full waveform inversion velocity modeling is being applied over the entire 38,000sq km area of CGG's Encontrado multi-client reprocessing project in the Perdido fold belt. The fine detail obtained can also aid geological interpretation. Image from CGG Multi-Client & New Ventures.

A ‘Gigante’ splash

Audrey Leon catches up with TGS’ Chris Corona on some of the geophysical firm’s latest programs offshore Mexico.

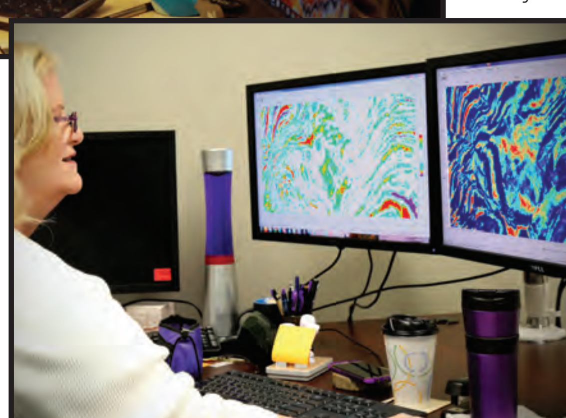


OE: What is your perspective on current activity off Mexico?

It’s very encouraging. The CNH (National Hydrocarbons Commission) has already announced two rounds for 2017. With the price of oil trending upward, we are anticipating that more companies will be taking a harder look at investing in exploration in Mexico. The CNH has done a great job getting a system into place for multi-client data and having a plan for licensing rounds that extends out a few years.

OE: Which offshore exploration areas are considered the most exciting?

Perdido has attracted the most attention, based on Round 1, Phase 4 (the deepwater round). Perdido interest is driven by large discoveries on both the US and Mexican side, such as Great White, Trident, Maximo and Trion, to name a few. The play type here has been concentric thrust propagated folds. That being said, our interpreters are very excited about what we are seeing on the 2D in the Mexican Ridges area, such as the Vera Cruz deepwater canyon system and Salina del Istmo. There is a big variation in play types amongst these areas.



TGS’ Connie VanSchuyver, technical training and development manager, reviews depth slices in the GoM.
Photos from TGS.

OE: Tell us about some of the multi-client projects TGS is currently working on in Mexico?

TGS is presently completing the depth processing of the Gigante survey along with the geochemical analysis of the 1100 cores that were taken as part of our Gigante SeaSeep program.

Gigante is a 190,000 km 2D regional survey. It covers the entire Mexican Gulf of Mexico. The purpose of the survey was to have a regional survey with a consistent set of acquisition and processing parameters.

These could be used to 1) tie into TGS’ seismic grid in the US Gulf of Mexico, and 2) tie into analog fields both in the US and Mexican Gulf of Mexico – knowing that there is no variation in the acquisition or processing parameters, and 3) creating a comprehensive regional understanding of the entire Gulf of Mexico basin.

Structural Interpretation and gravity and magnetic products are available from the survey.

Additionally, the Gigante SeaSeep program covers 625,000sq km (the entire Mexican Gulf of Mexico basin and the Caribbean). This survey uses multibeam data to identify natural seeps, which are cored and geochemical analysis performed. Approximately 1100 cores were taken. This information can be used determine the grade of hydrocarbon seeping out of the subsurface. This can be a very useful tool for exploration companies to determine where they would like to explore. The goal of Gigante is to provide industry with a comprehensive regional understanding.

OE: What is the long-term outlook for Mexico’s oil and gas industry from your perspective?

Much of this will depend on the 2018 presidential election. But, we are optimistic that no matter which party is elected, Mexico will still be open to foreign investment. The regulations could become more burdensome, which could deter some companies.

Chris Corona is the director of Latin America for TGS. He has been employed at TGS for 28 years, working in sales and project development.

Providing a boost

Audrey Leon speaks with Cesar Granados, Mexico country manager at Weatherford, to get the service company's perspective on Mexico's newly opened oil and gas industry, and what role Weatherford aims to play in it.

A Weatherford operation offshore Mexico. Photo from Weatherford.

OE: What are your thoughts on Mexico, pre- and post- the energy reform?
Weatherford entered Mexico in 1976, with a manufacturing facility for its cementing products. Today, we are one of Mexico's largest and most diversified service companies, thanks to our strong local infrastructure and core values, including our great local people, our entrepreneurial spirit, and our large footprint in the country.

Our industry is a living, ever-changing, cyclical environment. The drastic reduction in oil prices, capital flows, and exploration and production activities starting in mid-2014 offered an opportunity for us to innovate. We have transformed our operational workflows and are integrating technologies and processes in a way that creates value through operational efficiency. During a difficult time, we focused on developing and preserving the right combination of people, technologies, and processes.

OE: What does the drilling services sector look like in Mexico currently? What is your perspective on current activity offshore Mexico?
The recent industry challenges that we faced have made our sector even more solid and efficient than before. Our long-term commitment to doing business in Mexico drove our decision to preserve our local talent and capacity during this severe downturn.

Our preserved infrastructure now makes it possible for us to absorb additional activity resulting from CIEPS (integrated exploration and production contracts) and COPFS (financed public works contracts) migrations, and to become a major service provider for the independent operators taking on these projects.

There are some challenges for deepwater development in Mexico. If you compare the service profile and technical characteristics of deepwater fields in the US and Mexico, the biggest difference is the capacity and infrastructure in place. Mexico is working to explore and to develop this complex and relatively new environment.

Shallow water is different, as Mexico is already a leader in this area and has an entire infrastructure in place for further development. Weatherford has experience in both deepwater and shallow water environments. Some noteworthy successes in this area include integrated borehole enlargement operations using our RipTide RFID drilling reamer, which is especially effective in Mexico's deepwater fields, and a long and successful track record of installing liner hangers in the country.

OE: What are some of the challenges Weatherford sees in the Mexico market (workforce, equipment, etc.), and what are some ways the company has worked to overcome them?

There are many challenges in the industry today, not only in Mexico. During the current downturn, our industry has shifted to a single-purpose value mindset. Our clients had an urgent need for greater cost and operational efficiencies, innovative and integrated work flows as well as optimized production.

With regard to workforce, we continue to invest in human capital, maintaining close relationships with Mexican universities in order to incorporate and to develop local talent. This has remained important to us even during the recent downturn. We firmly believe that developing and strengthening our talent bench is essential to driving incremental performance into our business.

OE: As a company that has been present in Mexico for decades, what is the long-term outlook for Mexico's oil and gas industry from your perspective?
The biggest opportunities we anticipate will be in unconventional and offshore operations. Higher activity from the private sector will increase competitiveness in the marketplace, and will certainly help develop our local industry. Weatherford has reacted very quickly to the changes in the Mexican oil and gas market, adjusting the company through smart internal restructuring. However, to succeed in the Mexican oil and gas industry, we need to continue demonstrating our integrated approach and our capacity to provide high-quality service in all environments.

The energy reform was enacted at the right time and is attracting more and more investors to the country, so more opportunities will be available to all of us.

Cesar Granados has over 20 years' experience in the oil and gas industry, 17 of which have been with Weatherford. Granados holds a BSc in petroleum engineering and is pursuing an executive MBA. He is an active member of the Society of Petroleum Engineers, and has authored several technical papers and presentations.

Fanning the (E&P) **flames**

All eyes may be on Guyana, but there's plenty of other countries worthy of attention in South America. Audrey Leon surveys the current spike in exploration activity in the region.

While the downturn in oil prices has cooled many companies offshore exploration aspirations, more than a few majors and small firms are taking the plunge in South America.

After ExxonMobil's massive 2015 Liza find offshore Guyana, there are many who are interested in that upcoming oil-bearing country, as well as others, including neighboring Suriname. South of Brazil, there is Uruguay, where Total drilled the then-world's deepest water well, Raya, in 2016.

Traditional oil-bearing countries such as Colombia are also seeing renewed exploration investment from both international and national oil firms.

Colombia

Colombia is South America's third largest oil producer after Venezuela and Brazil, according to the US Energy Information Administration. At the end of 2016, the country's state-owned oil company Ecopetrol announced that it intended to ramp up exploration in 2017, both off- and onshore, to curb its falling production. In November, Ecopetrol's Exploration Vice President Max Torres noted that of the 15 exploration wells the Colombian operator planned to drill in 2017, five would be offshore (*OE:* January 2017).

US Independent Anadarko Petroleum is drilling offshore Colombia. In February, during its Q4 earnings call, the Houston-based oil company confirmed that the Purple Angel exploration well spudded in December and, as ***OE*** went to press, operations were ongoing, using Fred. Olsen's *Bolette Dolphin* drillship.

"We are testing effectively the Kronos discovery in this Purple Angel location right now," said Ernest A. Leyendecker, executive vice president of International and Deepwater Exploration, during the call. "When we're done, we're going to go up north and test another analogous structure to the feature we're on right now, called Gorgon. So, really a lot more to come in the context of the Grand Fuerte area gas frontier in the future."

Anadarko also said that it is evaluating multiple large-scale opportunities identified from the Esmeralda 3D seismic survey, which covers about 30,000sq km and potential drilling locations for possible operations in 2018 are being evaluated.

The *Bolette Dolphin* drillship offshore Colombia.
Photo from Anadarko Petroleum.

"We're obviously pretty encouraged about what we're seeing," Leyendecker added, who described the acreage as "pretty deepwater out there in the Grand Col area."

Anadarko has a 50-50 partnership with Ecopetrol on Purple Angel. Anadarko holds 100% working interest in the Gran Col area (Blocks Col 1, Col 2, Col 6 and

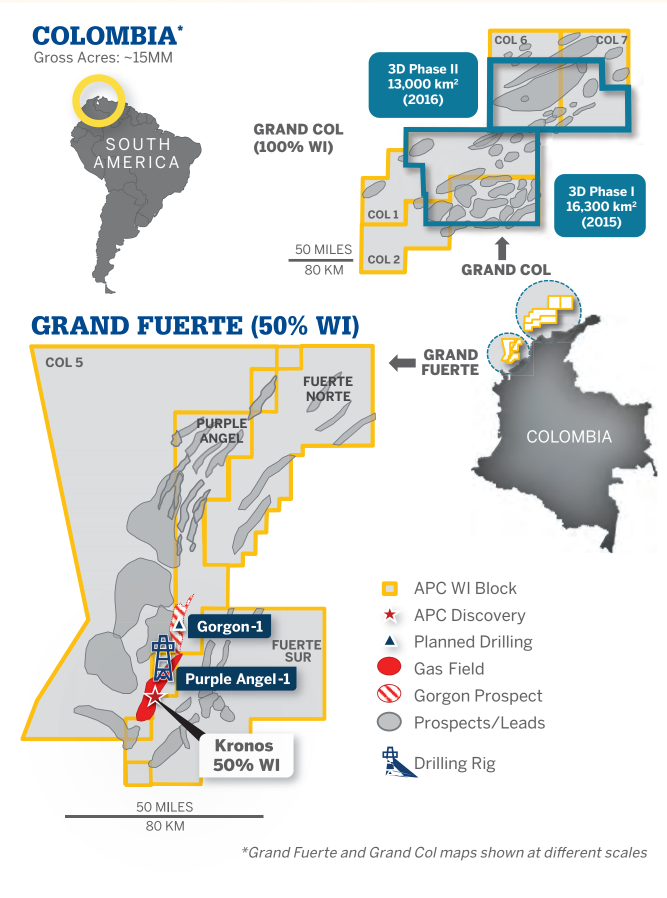
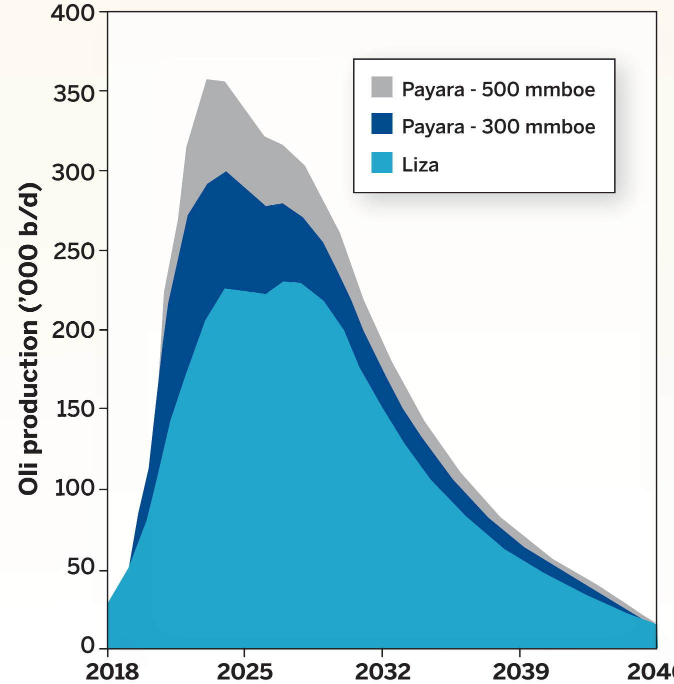


Image from Anadarko Petroleum's Q4 Operations Report.

Charting Guyana's oil production



Source: Wood Mackenzie.

Col 7), where the Esmeralda survey was conducted.

In early January, Spain's Repsol contracted Maersk Drilling's *Maersk Developer* semisubmersible drilling rig to drill the Siluro-1 exploration well in block RC-11, offshore western Colombia. Drilling is planned for Q2 2017 and will take about 42 days. The estimated contract value is US$12 million, including mobilization and demobilization, Maersk Drilling says.

According to a 2014 presentation by Repsol, Siluro is a lower Micocene Carbonate prospect, with 1.6 Tcf gas resources, in 90m water depth.

Guyana

Arguably, all eyes will be on Guyana in 2017, as US supermajor ExxonMobil aims to fast-track its recent major finds in the country. According to Exxon's Q4 earnings call late January, the firm expects final investment decision on Liza by year's end, with start-up possible by 2020.

In mid-2015, ExxonMobil confirmed the huge Liza discovery, in the Stabroek block, 120mi offshore Guyana. Ever since, the supermajor and its partners have been evaluating and increasing potential recoverable resource estimates at the block, which are thought to hover well over 1 billion boe.

The Stabroek block comprises 6.6 million acres (26,800sq km). Exxon subsidiary Esso Exploration and Production Guyana operates the block with 45% interest. Its partners include Hess (30%) and CNOOC Nexen Petroleum Guyana (25%).

In January 2017, ExxonMobil then made the ultra-deepwater Payara-1 well, inside the Starbroek block, which was drilled using the *Stena Carron* drillship to 18,080ft (5512m) in 6660ft (2030m) water depth.

Payara-1 encountered more than 95ft (29m) of high-quality, oil-bearing sandstone in two upper Cretaceous reservoirs of Maastrichtian-Aptian age – like those found at the Liza discovery, says analysts Wood Mackenzie. Exxon said a production test is planned to further evaluate the discovery and appraisal drilling is planned for later this year to determine the full resource potential. The Payara field is about 10mi (16km) northwest of the Liza discovery.

During its Q4 earnings call, Exxon said that two sidetracks have been drilled at Payara. "We moved very quickly to drill additional sidetracks in order to better define the reservoir," said Jeff Woodbury, vice president of investor relations and secretary, ExxonMobil. The company said a well test is underway, which would help the company better understand the full resource potential and development options.

In addition to Payara, Exxon also said that appraisal drilling at Liza-3 identified an additional high-quality, deeper reservoir directly below the Liza field, which is estimated to contain between 100-150 MMboe. This additional resource is currently being evaluated for development in conjunction with the Liza discovery.

The *Stena Carron* drillship will move next to the Snoek exploration prospect, about 6mi (10km) south of the Liza-1 discovery well.

In December 2016, Exxon awarded contracts to SBM Offshore for a 100,000 b/d floating production, storage and offloading (FPSO) vessel, a key step in moving the Liza field toward first production. SBM Offshore will perform front-end engineering and design for the FPSO, and, subject to a final investment decision on the project in 2017, will construct, install and operate the vessel.

Latin America

Apache: Offshore Suriname Position

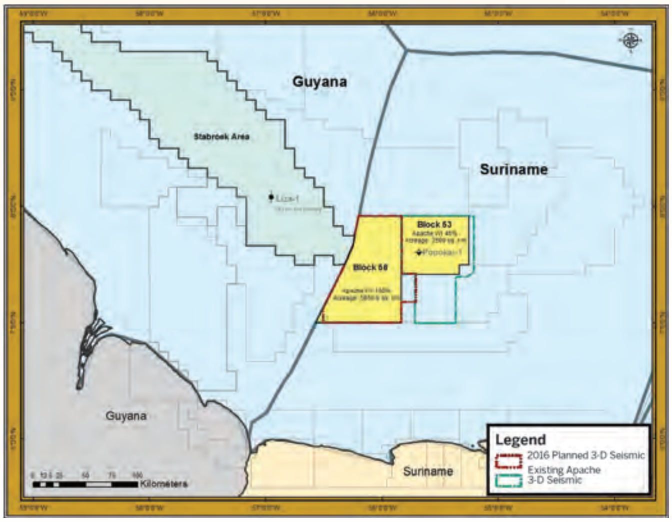


Image from Apache.

Peru offshore acreage map

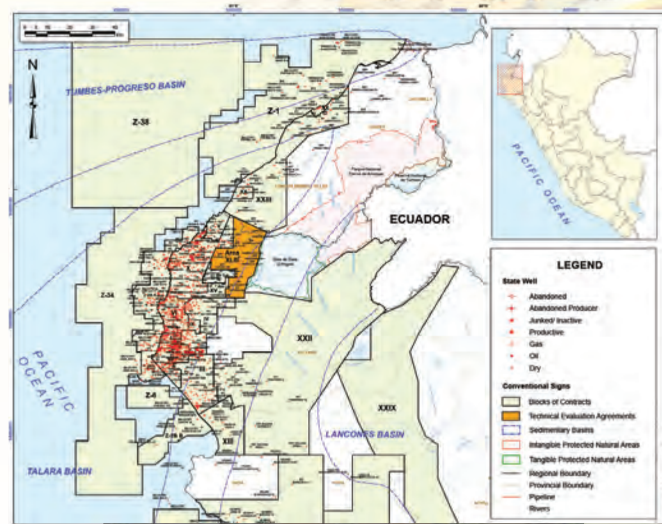


Image from PeruPetro.

At the time, Exxon also said it had applied for a production license and submitted its initial development plan for the Liza field to the Guyana Ministry of Natural Resources. The plan includes development drilling, operation of the FPSO, and subsea, umbilical, riser and flowline systems.

Wood Mackenzie said in early February that there are huge expectations for Guyana to become a serious upstream player by the next decade, despite the challenges associated with developing an oil industry from the ground up. "It's not often that a country goes from zero to 60 so fast like this," Matt Blomerth, Wood Mackenzie head of Latin America upstream research, told the *New York Times* in January.

"After [Exxon] drilled a dry hole at the Skipjack prospect in September, Payara and Liza-3 reconfirmed the high potential of the Cretaceous play in Guyana's deepwaters," Wood Mackenzie said in a statement in January. "Payara's proximity to Liza enables economies of scale for the area's development. The Guyanese government's approval of a $500 million oil and gas service hub on Crab Island will give added impetus."

Of course, there are challenges ahead, including a lack of infrastructure. Wood Mackenzie estimates wellhead gas volumes of 2.1-2.5 Tcf between Liza and Payara. "With no offshore infrastructure or nearby gas market, the partners will face high costs to dispose whatever gas that cannot be reinjected or flared," the consultants said.

However, Wood Mackenzie's analysis of Guyana remains optimistic, saying in January that Guyana's production could reach 350,000 b/d by 2023.

To address some of the country's growing needs, Guyana's Ministry of Natural Resources announced in January that it plans to have a new petroleum directorate established and functioning during Q1 this year.

The ministry says the new directorate will follow international models that separate policy development from regulation monitoring. A $965,000 (GY$200.7 million) budget was allocated in the 2017 for petroleum management.

Elsewhere in Guyana, UK Independent Tullow announced in February that it plans to acquire 3D seismic data over the offshore Orinduik license, awarded in 2016, and the Kanuku license. Both are up-dip of the Liza discovery. The two programs are expected to cover up to 6000sq km and will enable evaluation of attractive leads mapped on existing 2D seismic data.

Suriname

Tullow's Exploration Director Angus McCoss referred to the Guyana-Suriname basin as the industry's "hotspot at the moment," in the company's Q4 earnings call early February, and its Araku prospect there, a "game-changer." The company is calling its test of the Araku prospect, in offshore Block 54, its "main drilling event" this year.

Tullow plans to drill the high impact Araku prospect in 2H 2017. McCoss said that the reservoir Tullow is targeting is a Maastrichtian, a younger Cretaceous turbidite sand, and a similar-aged rock to what Payara is targeting off Guyana.

The block has a large structural trap with resource potential of 500 MMbo, and has been significantly de-risked by a 4000sq km 3D seismic survey carried out in 2015, says Tullow. A rig is currently being sourced for the well, which is expected to cost $14 million net to Tullow to drill. The Block 54 contract area is 8824sq km and is about 200km offshore in the Suriname-Guyana Basin.

"It's a giant prospect over a 300sq km closure," McCoss said. "It's a four-way structural closure. This is a structural closure, it's a dome-shaped structure, which is a good, safe, lower risk type of prospect to go for.

"[There] is a lot of follow-up potential in this area," he continued. "It's not just this play. There are other plays there are stratigraphic plays, carbonate plays. A great set of opportunities. We're hopeful for Araku. [It] is our best prospect in the portfolio. But, should it not [be], there are a lot of alternative play types to follow-up on in this rich acreage."

For Tullow and its partners Statoil and Noble Energy, the

Map of Blocks awarded during Uruguay's Round 2

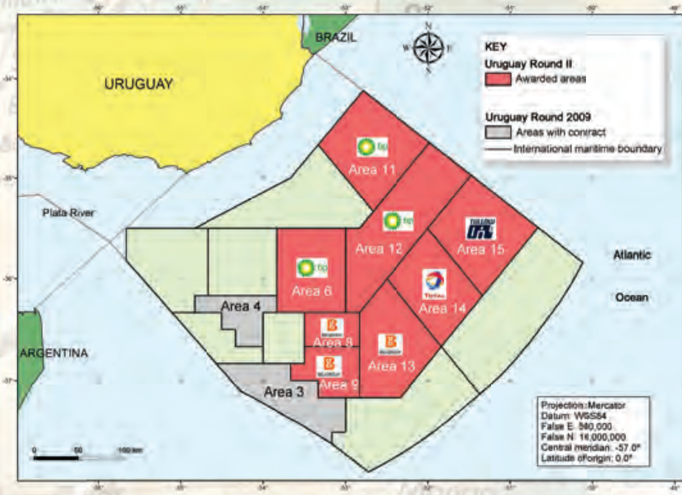


Image from ANCAP.

The *Maersk Venturer* drillship, which was used by Total for its Raya-1 exploration well offshore Uruguay. Photo from Maersk Drilling.

well is not just about opening a new play area, but also an exercise in keeping well costs down.

"The $14 million net to Tullow relates to about $40-45 million gross well cost," McCoss explained. "Now, if you compare that to previous years that would have cost about $100 million to drill. So, you can see [there is] quite a very significant offshore cost deflation in the sector that we're taking advantage of."

Other players with acreage in Suriname include US independent Hess, which is partnering with Exxon for Liza offshore neighboring Guyana. In May 2016, Hess picked up a one-third stake in Block 42 offshore Suriname from US-based explorer Kosmos Energy.

In Kosmos' Q3 earnings call, the firm said that it began a new 3D seismic survey of Block 42 in Suriname near the Peruvian-Guyana Suriname Basin, adjacent to the Liza discovery, in October 2016. Results are expected in early 2017. Kosmos' Chairman and CEO Andy Inglis said that the firm hopes to drill toward the end of 2017, into 2018, into Turonian-aged source rock. Inglis says there is a drill-ready prospect in Block 45, different from the trend seen in Liza offshore Guyana.

US-based Apache has interest in Blocks 53 and 58 offshore Suriname. In the company's Q3 earnings call, CEO John J. Christmann said the firm is very excited about its prospects in Suriname.

Timothy J. Sullivan, executive vice president, operations support, said during the call that Apache completed a 3D seismic shoot on Block 58 in September 2016, and expects to have a fully processed data set by Q3 2017. In Block 53, Apache will drill an exploration well in Q1 2017.

"While this is an attractive and sizable exploration prospect (in Block 53), very few wells have been drilled to this depth offshore Suriname, and as such, carries a significant amount of risk," Sullivan said during the call in November. "The dry hole cost to Apache for this well is estimated at less than $40 million."

Peru

In February, Regulator PeruPetro approved UK-based Baron Oil and partner Uruguay-based Union Oil and Gas Group's (UOGG) plan to drill the Cuy-Z34-13-1X exploration well offshore of northwest Peru in Block Z-34, some 15km from an existing producing field in the offshore/onshore Talara Basin.

The well will be drilled in 5764ft of water to a total depth of 12,553ft. Block Z-34 is in an undrilled deepwater basin and covers a 3713sq km area. Baron's internal estimates of gross unrisked best estimate (P50) prospective resources for the Cuy prospect is 413 MMbbl recoverable.

UOGG, which holds 80% interest, is continuing farm-out efforts for a partner to share the drilling costs. Baron hold the remaining 20%. The well, according to Baron, cannot be drilled until another partner comes on board, in addition to contracting a semisubmersible drilling unit, and all permits in place.

Uruguay

Uruguay has been in the spotlight because French oil major Total drilled the then-deepest water well in the world, Raya-1, there in 2016, using Maersk's ultra-deepwater *Maersk Venturer* drillship. However, while the Raya reservoir was believed to be good, not much more information has been released about the prospect since.

"Uruguay has been successful in making attractive offshore areas open for exploration activities," says Adrian Lara, senior upstream analyst, GlobalData. "So far key major companies have participated and some, such as Shell, BG, Tullow Oil, ExxonMobil and Inpex, remain in the country doing exploratory activity. Round 3 is supposed to be announced soon and is aimed at continuing collecting exploratory information on the offshore areas."

In January 2017, Tullow started a 2500sq km 3D seismic program offshore Uruguay to capture data over high-quality leads identified in Block 15 in the Pelotas Basin. **OE**

Latin America

South American **Spotlight**

Old and new provinces continue to bring forth new activity in Latin America, from new finds in Guyana to the ongoing pre-salt programs in Brazil. Michael Borrel sets out the detail.

Latin America has become increasingly attractive to both local and foreign investors. Mexico held its first ever offshore deepwater auction (Round 1.4), open to both local and international firms, in December 2016, which was comprised of 10 blocks in both the Perdido and Salina Basins in the Gulf of Mexico.

Eight of the 10 blocks were awarded to some of the largest oil and gas firms in the world, including BP, Chevron, CNOOC, ExxonMobil, Statoil and Total. Mexico's Round Two auctions, which will include both onshore and offshore blocks, will take place in summer 2017.

Pemex, Mexico's state-owned petroleum company, is set to

Number of active and future offshore projects and estimated CAPEX ($m) in select Latin American countries

	Argentina	Brazil	Colombia	Guyana	Mexico	Peru	Trinidad & Tobago	Uruguay	Venezuela
# of Projects	1	59	2	2	31	2	11	1	8
CAPEX ($Mn)	$165	$145,430	$2,000	$2,300	$65,023	$630	$4,531	$1,000	$7,750

Source: EICDataStream

increase production at its Abkatun-Pol-Chuc offshore reservoir complex, which is made up of 18 fields, of which 10 are currently productive. However, the reservoir complex is temporarily out of service due to a fire that destroyed the production platform. The engineering, procurement and commissioning (EPC) contract for the construction of a new platform was awarded to McDermott.

Sea Trucks Group (STG) was awarded a contract for its *Jascon 31* vessel to provide accommodation and lifting services.

During the December round, Mexico awarded Australia's BHP Billiton a 60% operatorship farm-out to partner with Pemex in its Trion development, which is in the deepwater Perdido area.

Brazil

Recent offshore contracting activity in Brazil has been mainly associated with Petrobras projects, with key contracts awarded for the massive Libra field in the pre-salt province. In September 2016, local company MFX do Brasil was awarded the supply of 33km of umbilicals for Libra's extended well test, while in November 2016, Halliburton obtained a contract to provide drilling services and equipment for the construction of up to nine wells.

The much-delayed tender for the 20-year charter of an FPSO for Libra's pilot production project has encountered another setback. A federal court has suspended the bidding process following an injunction from Brazil's shipbuilder's association SINAVAL, which claims that Petrobras is not complying with local content requirements.

Another Petrobras project closely watched by the industry is the expansion of the Mexilhão fixed gas platform. Local player Enaval was confirmed in September 2016 as the EPC contractor, with Radix Engenharia responsible for the detailed engineering.

Statoil, Brazil's second largest oil and gas producer, is progressing with the second development phase of the Peregrino heavy oil field. Cameron Sense, a Schlumberger unit, is understood to be supplying the drilling equipment package for the field's third wellhead platform, known as WHP-C.

Guyana

Last December, in neighboring Guyana, SBM Offshore was awarded a contract by ExxonMobil to perform front-end engineering and design for a 100,000 b/d FPSO that will operate on the Liza oil field. Subject to a final investment decision in 2017, SBM will also build, install and operate the production unit.

Argentina

Meanwhile, in July 2016, in Argentina, Enap Sipetrol awarded a contract to STG for pipelay work on the Magallanes field. The contract scope includes, among other elements, the engineering, project management and installation of three pipelines of different sizes. OE

Michael Borrel is Regional Analyst (North & Central America) at Energy Industries Council (EIC).

Michael is the EIC's Regional Analyst for North and Central America. He researches and analyses project information and contracting activity in the oil and gas, power, nuclear and renewables sectors in these regions.

Solutions

HAL broadens Dash system

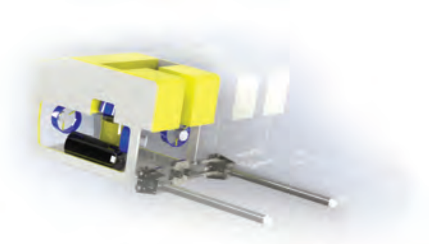
Halliburton (HAL) released the Dash Large Bore Subsea Safety System, which provides full electrohydraulic control of well safety and intervention functions. The fully customizable system brings new benefits to deepwater operators for completion and intervention work that improve critical well control of the subsea safety system, tubing hanger and deepwater subsea field developments.

HAL designed the system to isolate the lower landing string in six seconds or less, disconnect from the lower landing string in ten seconds or less and provide downhole data for greater confidence in decision-making.

The two larger bore sizes, 6.375in and 7.375in, in addition to the existing Dash 3in system, broadens the use of HAL electrohydraulic subsea safety systems. Operators will now have the ability to deploy this technology across the full breath of their ultra-deepwater offshore operations to help minimize operational risk.

Noble Energy used the Dash large bore system during recent plug and abandonment operations in the Gulf of Mexico. Dash served as the primary well control barrier and blowout preventer. According to HAL, this dual functionality eliminated the need for alternative measures during the operation, which reduced rig time by several days.

www.halliburton.com



STR enters inspection market

Subsea Technology & Rentals (STR) developed the SeaGamma Flooded Member Detection (FMD) System to inspect and monitor subsea structural members for the detection of water ingress.

With climate change warming our coastal waters, progressive marine growth means traditional methods of nondestructive testing inspection can be costly and inefficient. The STR SeaGamma FMD standard system has been designed to survey components up to 2m diameter from an inspection or work class remotely operated vehicle and requires no marine growth removal to deliver results.

The FMD inspection technique can also be applied to locate blockages in pipelines due to pigging or silt build up.

www.str-subsea.com

Archer develops SPARTAN plugs

Archer Oiltools has released the SPARTAN plug family, designed for well integrity during operations, well suspension and plug and abandonment (P&A) for all wells.

The SPARTAN plug delivers protection for short-, medium- or long-term suspensions, and rapid deployment and retrieval, which can lead to safer wells and reduced operational time and costs. In addition to the SPARTAN everyday plug, Archer Oiltools' plugs portfolio includes three additional plug systems – VAULT, HUNTER and SPEARHEAD.

The VAULT dual plug system enables two Archer plugs to be installed in one run, streamlining plug operations. The SPEARHEAD plug system is designed to withstand increased hangoff loads or pull forces, which improves the efficiency of P&A operations. The HUNTER tandem plug system allows a barrier plug to be run in combination with other downhole tools, due to its versatile design, which sets new standards in operational efficiency, saving the number of trips and rig time.

www.archerwell.com

Webtool designs resettable cutter

Hydraulic cutting systems specialist Webtool has developed a resettable emergency disconnect (ED) cutter for light and medium subsea well intervention. The Webtool guillotine cutter can now be reset subsea by remotely operated vehicles (ROVs), avoiding the need to return the cutter to the surface vessel for resetting.

The Webtool emergency cutter is designed to be a simpler and quicker emergency disconnection for mixed material bundles. In the event of an emergency disconnection, the Webtool cutter is reset by a ROV releasing the blade and recharging the hydraulic system. The ROV then places the new bundle in the jaw of the cutter and cutter is set and ready. The bundles can then be cut in a single guillotine action taking just a few seconds.

The Webtool cutter offers weight savings compared with other emergency disconnect methods, and is retrofit to intervention systems.

www.webtool.co.uk

Activity

Subsea UK awards winners

The Subsea UK awards winners have been officially announced, with Hydro Group winning the Subsea Company of the Year award, and EC-OG winning the Small Company of the Year award.

"Being presented with this award is testament to the growth and success the company has achieved over the past three decades," said Doug Whyte, managing director, Hydro Group. "I am proud of our team for their dedicated support, adapting to the ever-changing industry, while also securing a stronghold in additional markets including oceanographic and renewable energies, and defense."

In addition, the Global Exports award went to JDR Cable Systems, the Innovation for Safety award went to The Underwater Centre, and the Innovation and Technology award went to Proserv.

Individuals also received recognition. Aidan O'Sullivan from Universal Pegasus was recognized as the Young Emerging Talent, and Ian Donald of Enpro Subsea was recognized as the individual who has made the most outstanding contribution to the subsea sector.

"The past two years have been extremely challenging for the oil and gas sector, however we have continued to see an unwavering commitment from companies of all sizes to drive a real change across our industry," said Neil Gordon, chief executive of Subsea UK. "Despite the ongoing challenges we face as an industry, it's vital that we continue to celebrate and recognize the finest talent, leadership and contributions as we adapt to this new environment in the coming years." ▪

SUBSEA UK™ AWARDS

SPE/IADC returns to The Hague

Bringing together drilling professionals from around the world, the leading SPE/IADC Drilling Conference and Exhibition returns this month (March) to The Hague.

This year's technical program features high caliber peer-selected papers and sessions covering current applications and emerging technologies within all phases of exploration and production. The conference will provide an opportunity for learning and collaboration during sessions, forums, and training courses, while the exhibition running alongside will showcase the latest technologies from around the world.

International petroleum professionals, and industry leaders, innovators and investors will be in attendance including panel session speakers from Schlumberger; Energy Ventures; BP; McLaren Applied Technologies; Maersk Drilling; European Space Agency (ESA) and Evercore.

Israel's Delek in Ithaca takeover bid

Israel's Delek Group has made a US$524 million offer for UK independent explorer and producer Ithaca Energy.

The offer would see Delek take over Ithaca's UK North Sea portfolio, including the Greater Stella Area development, a floating production project, which went into production in mid-February.

Delek, which is a partner with Noble Energy on the massive Leviathan and Tamar fields offshore Israel, says the move is part of its strategy to expand its international energy operations. Delek already holds 19.7% interest in Ithaca. Last year, the firm attempted to acquire a 20% stake in EnQuest's Kraken development, but the deal fell through.

Scottish decom fund launched

A new US$6.29 million (£5 million) fund has been launched to provide opportunities for the supply chain in Scotland to benefit from the decommissioning of North Sea infrastructure.

The Decommissioning Challenge Fund (DCF), launched by the Scottish government, will support infrastructure upgrades and innovation in salvage and transport methods at Scotland's ports and harbors.

It will also encourage engineering scoping work at key sites to build business cases that will attract further private investment. Alongside the Decommissioning Action Plan, launched by Scottish Enterprise, and Highlands and Islands Enterprise last year, the DCF will help Scotland's oil and gas sector make the most of decommissioning opportunities at home and abroad.

Cathie eyes US wind

Offshore geoscience and geotechnical engineering consultancy Cathie Associates has formed a US entity: Cathie Associates, based in Boston.

The move is part of the company's plans for international expansion and will enable them to serve offshore wind development in the US.

David Cathie, CEO and founder of the international consultancy commented: "We have been following the industry for over five years and supporting a number of planned developments; we feel the time is right to demonstrate our future commitment to US offshore wind, and to recognize the importance of local content and American jobs."

Petrobras, Halliburton ink technology pact

Halliburton and Brazil's Petrobras have signed a technology cooperation agreement that will advance collaboration in a diverse set of projects targeting complex reservoirs such as deepwater pre-salt and mature fields, offshore Brazil.

The multi-year agreement will facilitate the development of innovative solutions in geophysics, drilling and completions, reservoir characterization, well testing, flow assurance and production. The project portfolio will focus on three main challenges: reducing well construction investment, long-term reservoir monitoring and increasing well productivity. The project collaboration uses Halliburton's Brazil Technology Center in Rio de Janeiro.

Editorial Index

What's next

Coming up in OE April

Asset Integrity

- EPIC – Brownfields
- Subsea – Tiebacks
- Production – Well Intervention
- Drilling & Completions – Drilling Technologies
- Regional Overview – Southeast Asia

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