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OE's August 2016 cover features the subsea compressor manifold station for Åsgard during the summer 2013 installation. Image courtesy of Statoil. Photo taken by Øyvind Hagen.

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

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What's Trending


The Al-Shaheen field. Photo from Maersk Oil.

Mixed bag

- Total ousts Maersk at Al-Shaheen
- Woodside sanctions $1.9 billion Greater Enfield project
- Wood Group wins Leviathan work

Activity

Shell updates Brent decommissioning plan

Super major Shell has set out its plans for decommissioning the Brent field facilities in the UK North Sea, including leaving its foundations in place. Next month, Elaine Maslin provides an update on the project, of which Shell has already spent 10 years developing the decommissioning plan.


The Brent Delta topsides. Photo from Shell.

People

CNOOC names new CEO

China National Offshore Oil Corp. (CNOOC) has appointed a company chairman, Yang Hua, as its new new CEO. Hua replaces Li Fanrong who will join China's National Energy Administration as deputy director.

Undercurrents

Under the sea

OE is proud to produce our first-ever Subsea Factory issue. In our August 2016 issue, we take our readers through the accomplishments of subsea processing while highlighting new technologies. ***OE***'s European Editor Elaine Maslin looks at solutions for subsea power distribution (p 20), variable speed drives (p 24), and subsea oil storage options (p 30). Rystad Energy and Quest Offshore shed light on the market outlook (p 26) and outline current project activity (p 29), respectively.

This issue also features a special report on the Dutch Offshore sector (pp 67-82), with particular emphasis on how the Netherlands is further embracing the offshore renewables market during this latest downturn.

"A number of operators have increased production from subsea wells by removing the near wellbore damage from the sand face. The use of a rigless option again provides for a substantial reduction in cost to perform the work."

The month of August is always a special time around ***OE*** as we get ready for our annual Deepwater Intervention Forum on 9-11 August 2016. This issue highlights the latest technologies in the sector, including recent game-changers that will be celebrated at the event, held in Galveston, Texas. Managing Editor Audrey Leon spoke with the forum's board members who highlighted positives in the sector (p 40). While most of the discussion didn't make it into the final article, we'd like to include some extra responses here. In terms of game-changing technologies, the board agreed rigless P&A is a worthy candidate, but also rigless subsea hydraulic stimulation equipment.

"A number of operators have increased production from subsea wells by removing the near wellbore damage from the sand face. The use of a rigless option again provides for a substantial reduction in cost to perform the work," one board member said.

Of course, while the industry faces many challenges due to the lowered oil price environment, one board member said that the industry needs to prepare for the emergence of a lack of skilled workers, if training isn't continued during the downturn. "[Training] will assist in reducing the consequence of the reduction in staff and help many companies perform safely and efficiently," one board member said.

The intervention market, while affected by the lowered oil prices, is very much needed, especially during times like these. A new report called "Global Well Intervention Market 2016-2021" says worldwide, well intervention is forecast to grow at a CAGR of 4.34% from 2016-2021, on account of rising demand for oil and gas, along with an aging well stock.

The report, from analyst firm ReportsnReports, says that Africa is the highest growing market led by Nigeria; North America will see high growth with the US providing momentum, while Europe is having sluggish growth.

Last, but certainly not least, this issue takes a look at activity in the North Sea, including the UK and Norwegian sectors (p 84). We also present an in-depth look at Statoil's Johan Castberg development (p 16). As the Norwegian oil major strives to bring down costs on the field development, it has moved to deploy new direct current fiber optic (DC/FO) cable technology for its power and communication infrastructure.

We're also proud to announce our new, enhanced digital edition: **ow.ly/Dol0302vIMg**. We hope you enjoy it reading this issue as much as we enjoyed bringing it to you. **OE**

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PUBLISHING & MARKETING
Chairman/Publisher
Shaun Wymes
swymes@atcomedia.com

EDITORIAL
Managing Editor
Audrey Leon
aleon@atcomedia.com
European Editor
Elaine Maslin
emaslin@atcomedia.com
Asia Pacific Editor
Audrey Raj
araj@atcomedia.com
Web Editor
Melissa Sustaita
msustaita@atcomedia.com
Contributors
John Bradbury
Meg Chesshyre
John Sheehan
Editorial Assistant
Jerry Lee

ART AND PRODUCTION
Bonnie James
Verzell James

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

PRINT
Quad Graphics, West Allis, Wisconsin, USA

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OPINION

The Barrel

Making the best of Brexit

The big surprise over the last few weeks was of course the UK referendum decision to exit the European Union (EU). At first sight, it looks like a vote for independence over economics. While the first part of that is certainly true, the economic aspect should be measured in years, and not days or weeks.

None of the politicians on either side of the debate emerge with any credit, given the widespread scaremongering, misrepresentation and duplicitous conduct on show. That has now been extended post-referendum with calls for the EU vote to be re-run and Nicola Sturgeon proposing a second Scottish independence referendum. Both suggestions represent an affront to democracy. They are also a big negative from an economic perspective because they exacerbate the uncertainty around the consequences of Brexit, which in turn jeopardizes key investment decisions.

The big risk is that Brexit jitters somehow trigger a global financial crisis that significantly impairs crude demand.

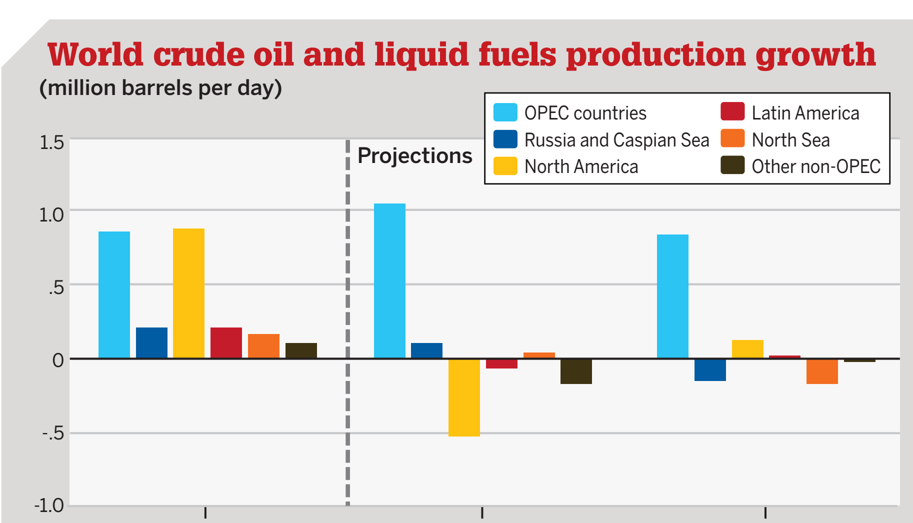
Like it or not the people have spoken and both politicians and the public should accept and respect that decision, and get on with it.

Another important consequence of the vote to leave is that it has shone a light on the fragility of the EU. Italian banks are on the brink of a crash, and Greece shows no signs of an economic recovery after seven years of recession and needs for a third bailout. Factions in France and the Netherlands want their own EU referendums. To compound matters, European Commission President Jean-Claude Juncker, an unelected bureaucrat, has reacted to the vote more like a petulant schoolboy than a respected statesman.

The fact is that there is a deep interdependence between the EU and the UK, so it is in the interests of both parties to come to a deal that minimizes the damage to both. Contrary to recent political and media rhetoric, when the time comes to negotiate its exit from the EU, the UK will be in a strong position given the extent of the UK's trade deficit with the EU (£24 billion in the first three months of this year alone) and because the UK contributes 12% to the EU budget (filling the gap will be a headache to the remaining members unless a phasing out can be agreed). The big issue is "Freedom of movement v. Free trade." Given the UK voted for controlled immigration, not no immigration, it's reasonable to assume that skilled negotiators (rather than politicians) on both sides will find a compromise that affords the UK Associate Member status. This would preserve existing free trade benefits without having to negotiate multiple individual trade deals.

As for the threat of another Scottish referendum, as a Scottish resident the feeling I get is that there is little appetite for that on the part of a referendum weary population. Moreover, the economics simply do not add up. Leaving the UK would put the £50 billion of annual Scottish exports to the rest of the UK at risk (Scotland exports just £12 billion to Europe). It would also forego the extensive subsidies that Westminster pays to shore up the Scottish budget deficit. In that event a combination of reduced public spending and higher taxes would be required.

As the drama plays out, the US dollar's value continues to rise. That will make it more difficult for crude prices to continue their upwards march even though the supply and demand balance is tightening. On the other hand, UK companies with US dollar revenues will find a welcome tailwind. The big risk is that Brexit jitters somehow trigger a global financial crisis that significantly impairs crude demand. In that event, crude prices will be well down the queue in our list of worries. In times of great uncertainty such as these it is always best to remember that things rarely turn out as bad as we feared or as well as we hoped. OE



Source: Data from the US Energy Information Administration.

***Colin Welsh** is head of international energy investment banking at Simmons & Company International, part of Piper Jaffray. He studied accountancy, economics and law at the University of Aberdeen and qualified as a Scottish Chartered Accountant with Ernst & Whinney (now EY).*

NEWS

Global E&P Briefs

A Mexico sets Round 2 terms

Mexico's Ministry of Energy will auction 15 shallow water areas in the Gulf of Mexico as part of Round 2.1. The blocks up for bid cover 8908sq km. The blocks include four shallow water tracts in the Tampico-Misantla basin. The area is thought to contain around 480 MMboe prospective resources and an original volume of approximately 220 MMboe. There is one block being auctioned off Veracruz, thought to hold an estimated 133MMboe prospective resources. Lastly, there are 10 blocks in the basins off the southeastern Gulf of Mexico up for grabs, with around 973 MMboe prospective resources and an original volume of 649 MMboe.

B Seismic ramps up off Mexico

Seismic activity offshore Mexico is ramping up with recent projects by Searcher and Fugro.

Searcher Seismic is acquiring the Buscador Near-Shore 2D seismic survey, offshore Mexico, using the *BGP Pioneer* vessel in early July. The project comprises 11,200km of high quality, long-offset 2D data and specifically targets the near shore areas covering rounds 2, 3 and 4.

Fugro has deployed multi-purpose offshore survey vessel *Fugro Gauss* to join the *Fugro Brasilis* offshore Mexico. Both Fugro vessels are using hull-mounted multibeam echosounders and sub-bottom profiler systems to map an area of approximately 625,000sq km. The survey is being conducted for TGS as part of its industry-funded, multiclient Gigante Survey, which also includes a regional 2D seismic survey.

C Lula FPSO starts up

Production started at the *Cidade de Saquarema* floating production and storage offloading unit on Petrobras' giant Lula field, offshore Brazil. Production at the first well, 8-LL-81D-RJS, stabilized at a rate of 30,000 b/d. The *Cidade de Saquarema* can process 150,000 bbl, and compress up to 6 MMcm/d of natural gas, and is currently moored in 2120m water depth. The vessel is owned and operated by a joint venture including SBM Offshore, Mitsubishi, Nippon Yusen Kabushiki Kaisha, and Queiroz Galvão Óleo e Gás.

D Noble brings Gunflint online

Noble Energy started production at Gunflint in the deepwater Gulf of Mexico in late July.

The Gunflint oil development, in Mississippi Canyon Block 948, is a subsea tieback to the Gulfstar One (*pictured*) facility owned by Williams Partners and Marubeni Corp. The two-well field is ramping up and is anticipated to reach a minimum gross production of 20,000 boe/d, with oil representing approximately 75% of the volumes produced, with 5000 boe/d net to Noble.

E Petrobras divests fields

Nine shallow water fields in the states of Ceará and Sergipe will be put up for sale as part of Petrobras' divestment plan.The fields in Ceará include Curimã, Espada, Atum, and Xaréu.

In Sergipe, the fields are Caioba, Camorim, Dourado, Guaricema, and Tatuí. The fields had an average production of 13,000 boe/d in 2015.

F Liza-2 shows billion bbl potential

New drilling results at ExxonMobil's deep water Liza discovery offshore Guyana have confirmed recoverable resources of between 800 million and 1.4 billion boe.

The Liza-2 well encountered more than 58m (190ft) of oil-bearing sandstone reservoirs in Upper Cretaceous formations. The well was drilled to 5475m (17,963ft) at 1692m (5551ft) water depth. The Liza wells are in the Stabroek block, some 193km (120mi) offshore Guyana. Liza-2 is about 3.3km from Liza-1.

G OGA begins UKCS seismic

The UK's Oil and Gas Authority has begun a seismic campaign to collect between 10,000-15,000km of new seismic data from under-explored frontier areas on the UK Continental Shelf. PGS vessel the *Nordic Explorer* will carry out seismic surveys across the East Shetland Platform, which includes the East Orkney Basin, East Fair Isle Basin and Dutch Bank Basin. WesternGeco vessel *WG Magellan* will carry out seismic surveys around South West Britain,

including; the Celtic Sea, Western English Channel, Bristol Channel, St George's Channel and the Irish Sea. Acquisition is expected to be completed during Q4 2016 and data released to industry in Q2 2017.

I EnQuest makes GKA hit

UK independent EnQuest has confirmed a discovery on the Eagle exploration well in the Greater Kittiwake Area in the UK Central North Sea.

Preliminary analysis indicates Fulmar oil bearing reservoir was encountered with a vertical thickness of 67ft and excellent reservoir properties. No oil water contact was encountered, representing potential upside volumes on the flank of the structure. Further evaluation of the Eagle results is ongoing.

J Porcupine gets 3D seismic

Norwegian seismic firm PGS is performing a new 3D seismic program in the Porcupine Basin offshore Ireland for Woodside.

The Bréanann 3D seismic program is over 2400sq km.

The program is expected to take five weeks to complete, but the processed and interpreted results will require many months thereafter.

K Woodside adds Senegal acreage

Australia's Woodside Energy has agreed to acquire all of ConocoPhillips' (COP) assets offshore Senegal, West Africa, for US$430 million.

The deal will see COP paid $350 million, then $80 million on completion, for 100% of the shares in ConocoPhillips Senegal, which holds a 35% working interest in a production sharing contract (PSC) with the government of Senegal covering three offshore exploration blocks, Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore. The PSC includes the FAN deepwater oil discoveries and the deepwater, basin opening SNE discovery with an estimated 560 MMbbl recoverable oil, is likely to be developed as a subsea project tieback to a floating production vessel.

L First gas at Alba B3

Houston-based Marathon Oil achieved first gas production from its new Alba B3 compression platform offshore Equatorial Guinea.

Production from the B3 platform allows Marathon Oil to convert approximately 130 MMboe of proved undeveloped reserves, more than doubling the company's

H ENGIE spuds Cara

ENGIE E&P Norge spudded the Cara exploration well in PL 636 in the northern Norwegian North Sea. The well is 35km offshore and approximately 6km from the Gjøa field in about 350m water depth.

The well, drilled by the *Transocean Arctic* semisubmersible drilling rig (*pictured*), is a standard exploration well, of conventional design, with a four string casing program.

In case of discovery, ENGIE will execute a drill stem test for an additional 25 days to assess the size of the reservoir. In the case of a commercial discovery, Cara could be a potential tieback to the Gjøa platform.

ENGIE E&P Norge, previously GDF Suez, is operator (30% interest) with partners Idemitsu Petroleum Norge (30%), Tullow Oil Norge (20%) and Wellesley Petroleum (20%).


Photo from Wintershall.

Contracts

Saipem gets Zohr work

Saipem won an engineering, procurement, construction and installation (EPCI) contract on the supergiant Zohr gas field off Egypt.

Saipem will install a 26in gas export trunkline and 14in and 8in service trunklines, as well as conduct EPCI work on six wells and the installation of the umbilical system.

Saipem will mobilize a fleet of vessels to carry out offshore operations, consisting of the ultra-deepwater pipelayer *Castorone*, the semisubmersible pipelayer *Castoro Sei*, the trench/pipelay barge *Castoro 10*, and other specialized vessels.

Saipem aims to complete work by the end of next year.

Aker, Idemitsu in Vietnam contract

Idemitsu Oil and Gas chose Aker Solutions to provide engineering services for the development of oil and gas resources in the Nam Con Son basin offshore Vietnam.

It is the first project for Aker Solutions and Idemitsu together in Asia Pacific and marks Aker's expansion into Vietnam.

The nine-month contract is for front-end engineering design (FEED) work for the Sao Vang and Dai Nguyet developments in the Idemitsu-operated blocks 05-1b and 05-1c in the Nam Con Son basin.

Idemitsu will use the FEED to make an investment decision for the first phase of development.

remaining proved developed reserve base in Equatorial Guinea.

The Alba field, one of the largest producers in the Gulf of Guinea, is located about 32km offshore from the capital Malabo, on the island of Bioko.

M BP sanctions Atoll

BP is targeting 1H 2018 for first gas from its deepwater Atoll field offshore Egypt. The firm has sanctioned Phase 1 development targeting up to 300 MMcf/d, with backing from the Egyptian Natural Gas Holding Co. (EGAS).

Phase 1 will comprise an early production scheme involving the recompletion of the existing exploration well as a producing well, the drilling of two additional wells and the installation of the necessary tie-ins and facilities. The Atoll wells will be drilled using Ensco's *DS-6* ultra-deepwater drillship, which is expected to start drilling in August for roughly 24 months.

N Noble to drill Tamar-8

Noble Energy will drill the Tamar-8 well offshore Israel in Q4 2016. Drilling will take about four months, including completion and connection to the production system. The budget is approximately US$265 million. Tamar-8 is designed to accelerate optimal production from the Tamar reservoir, and is expected to increase the redundancy in the production system and enable maximum supply during peak demand.

Tamar-8 is 100km west of Haifa, in 1670m water depth, with its final depth targeted at 5050m below sea level.

O Fugro studies India

Fugro has won a geotechnical site investigation contract fom ONGC India for the KG-DWN-98/2 project on the east coast of India. Fugro will gather site specific data to aid in the design and later installation of wellheads, manifolds, platforms, floating platform, storage and offloading vessel anchors,

Shawcor gets Tuxpan pipeline work

Canada's Shawcor received a conditional contract worth approximately US$231 million from Infraestructura Marina del Golfo (IMG), to provide pipeline coating solutions to the Comisión Federal de Electricidad (CFE) Sur de Texas – Tuxpan gas pipeline project.

Shawcor will provide coating approximately 690km of 42in pipe with the application of concrete weight coating in a variety of thicknesses (2.25in, 2.752in and 3.5in) and supply the installation of 5000 sacrificial anodes. Coating is expected to commence in the beginning of 2017 and complete by the end of 2017.

The Tuxpan Gas Pipeline project will transport natural gas along an underwater route in the Gulf of Mexico, from the South of Texas, to Tuxpan, Veracruz in Mexico. It will supply natural gas to the CFE's power generation plants in multiple regions of the country.

First Subsea wins Appomattox mooring work

Shell Offshore selected First Subsea to supply ballgrab subsea mooring line connectors for the Appomattox development in the deepwater Gulf of Mexico.
The semisubmersible four-column production platform will be moored in approximately 7200ft (2195m) of water using 16 Series III ballgrab subsea mooring connectors (SMCs) arranged in 4x4 clusters. The SMCs, with a MBL of 26,221kN (2600 ton), are manufactured in compliance with ABS 2009 Approval for special subsea mooring connectors. ■

umbilicals, pipelines and flowlines. Fugro will deploy its deepwater geotechnical vessel *Fugro Voyager*, which will perform work in water depths ranging from 50-1500m, starting by end of Q3 2016.

P Santos plugs Natuna appraisal

Santos has completed drilling the AAL-4XST1 appraisal well in the Northwest Natuna permit area, offshore Indonesia.

The well intersected the primary G Sand and secondary K Sand targets, which were fully cored for further analysis.

Drill stem tests (DSTs) were performed on both reservoirs and oil flowed successfully to surface, assisted by electrical submersible pumps, due to the heavy oil's viscosity. The G Sand DST showed an average stabilized flow rate of 828 bo/d, on a 64/64in choke, for a 10.7 API oil. The K Sand, with a 13.1 API oil, initially flowed at 1120 bo/d on a 64/64in choke, but after a mechanical failure of a downhole sand screen prevented stabilized flow, the rate varied from 536-1959 bo/d. The well, and was plugged and abandoned as planned and within budget.

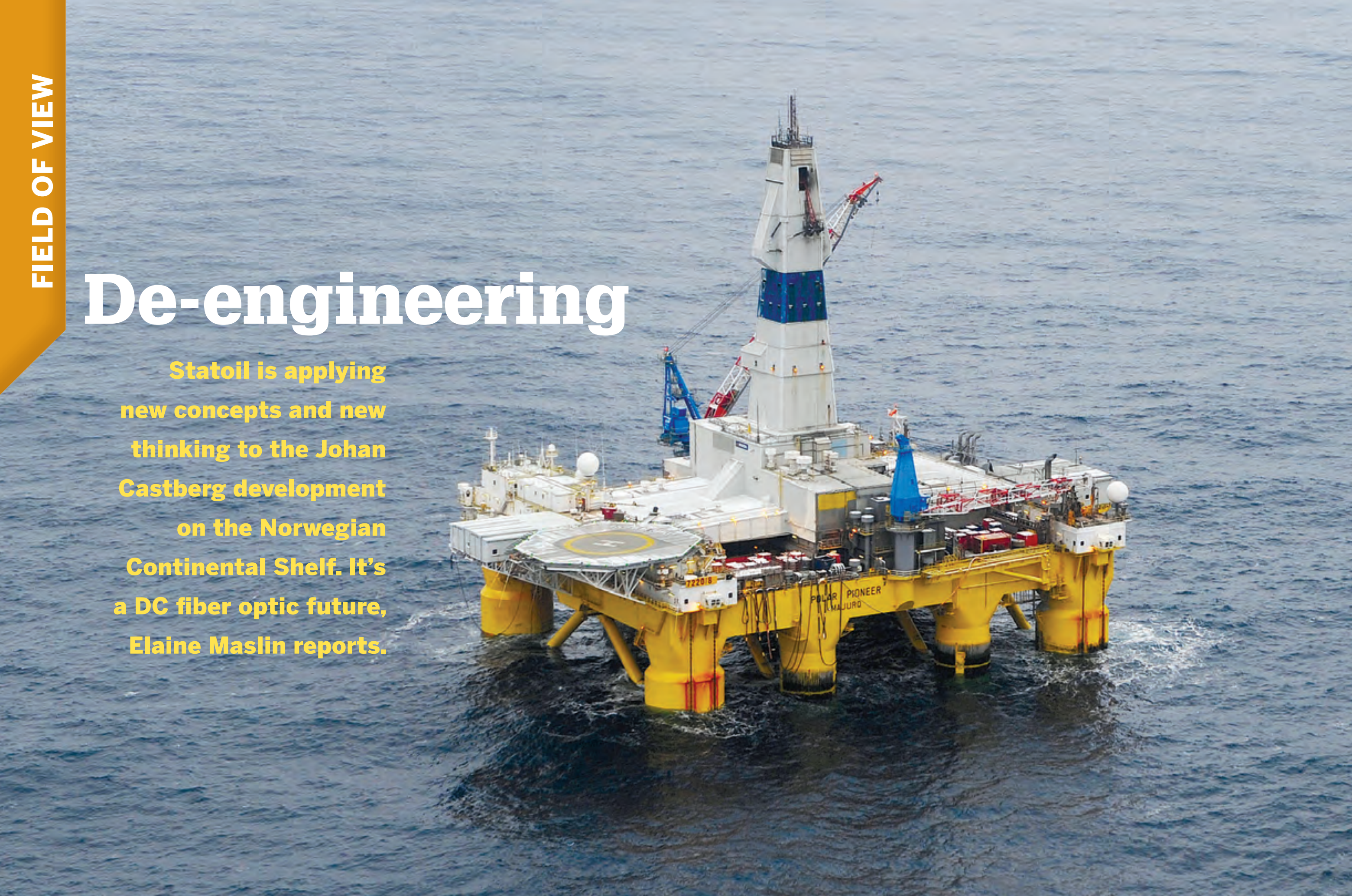
Q Quadrant to drill Driftwood-1

Quadrant Energy has optedto drill the Driftwood-1 well, instead of the Palmerston-1 well, in the Carnarvon Basin, offshore Western Australia, due to costs.

Driftwood-1 is in WA-320-P in the Barrow sub-basin of the Northern Carnarvon Basin, offshore Western Australia, approximately 1km north of the Rosily-1A exploration well which had minor oil shows.

Quadrant Energy will use the Noble Tom Prosser jackup drilling rig, with operations starting 1 August.

The well objective is to test the Early Cretaceous sandstones of the Mardie Greensand Member, Birdrong Member and Zeepaard Formation in a low-relief, northeast-southwest trending four-way dip closure.



De-engineering

Statoil is applying new concepts and new thinking to the Johan Castberg development on the Norwegian Continental Shelf. It's a DC fiber optic future, Elaine Maslin reports.

During this year's Subsea Valley Conference in Olso, Norway, Lundin's CEO Kristin Færøvik made a typically bold statement: "The good thing about the [low] oil price is it forces us to do things differently. The price had got too high on the Norwegian Continental Shelf. That's part of my optimism."

The amount of capex shaved off projects was a prominent topic for speakers at the annual event. Statoil's CEO Eldar Sætre stated that having had average US$70/bbl capex in 2013, some 80% of the firm's project portfolio now stood at $45/bbl and that was dropping to below $40/bbl.

But, while a large amount of that saving has been helped by a 25-30% drop in rig rates, there has also been, even before the oil price plummet, a hunt for innovative and smart solutions to help reduce costs and simplify developments.

Johan Castberg
(21 September 1862 – 24 December 1926) was a Norwegian jurist and politician best known for representing the Radical People's Party (Labour Democrats).

The Johan Castberg development is a case in point. Capex costs have been reduced by nearly 50%, from $11.3 billion to about $6 billion, thanks to "selecting a floating project combined with efficient subsea solutions and an effective drainage strategy," Sætre told Subsea Valley. "Innovative solutions and engineers with good smart ideas" have been brought to bear.


An artist's illustration of the FPSO. Image from Statoil.

One solution, which Statoil has been working on with French telecommunications cables firm Alcatel Lucent Submarine Networks (ASN), was to develop a new subsea power and communications cable system, reducing and simplifying the infield architecture. Statoil has also been taking a more risk based approach to infield flowlines protection and reassessed its drainage strategy.

The field

The Johan Castberg area is regarded as the next major development in the Norwegian Barents Sea, opening up a new province in the north. A final investment decision has been set back from the original mid-2014, with production start-up in 2018, to today's planned 2017 decision, with first oil possibly by late-2022. Delays have focused on costs, but also disappointing exploration results in the area and tax changes.

Transocean's *Polar Pioneer* semisub drilled the Skrugard prospect in 2011, now part of the Johan Castberg field.
Photo: Harald Pettersen/Statoil.

Johan Castberg, previously known as Skrugard, comprises three oil fields, Skrugard, Havis and Drivis, discovered in 2011, 2012 and 2014, respectively, in 380-400m water depth in PL532. The fields sit in a relatively under-produced part of the world. The nearest developments to Johan Castberg are Snøhvit, about 100km to the south, which has been producing since 2007, and Eni's Goliat, the Barents Sea's first oil development, some 150km away, and which only came onstream this year. Goliat is some 240km from Melkøya.

A key decision for the field has been around having a pipeline to shore, favored by the Norwegian government, and initially by the field partners, versus tanker offloading.

Early this year, Aker Solutions was selected to provide a concept study, focused on a floating production, storage and offloading (FPSO) unit, which will have a winterized design, qualified for ice loads, in the harsh Barents environment, plus measure including deck heating and falling ice protection, with tanker offloading. IKM Ocean Design also won a two-year contract for subsea integration pre-FEED and FEED, covering pipelines, risers, cables, tie-ins and related structures.

Reducing costs

The drainage strategy on Johan Castberg is based on long, horizontal producers, containing autonomous inflow control

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	2013	2014	2015	2016
Shallow (<500m)	74	73	56	9
Deep (500-1500m)	19	31	19	6
Ultradeep (>1500m)	34	13	12	4
Total	127	117	87	19
Start of 2016	127	114	72	-
date comparison	-	3	15	19

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

Reserves in the Golden Triangle

by water depth 2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Brazil			
Shallow	9	34.50	333.28
Deep	13	1,316.00	1,695.00
Ultradeep	41	11,586.00	12,773.00
United States			
Shallow	10	70.6	155.00
Deep	18	880.36	1,193.57
Ultradeep	21	2,967.00	2,818.00
West Africa			
Shallow	109	3,777.00	14,111.56
Deep	31	3,392.50	5,000.00
Ultradeep	10	1,335.00	1,000.00
Total	253	25,324.46	38,746.13
(last month)	(261)	(25,460.96)	(40,341.13)

Greenfield reserves

2015-19

Water depth	Field numbers	Liquid reserves (mmbbl)	Gas reserves (bcf)
Shallow	861	33,080.72	423,955.13
(last month)	(890)	33,712.87)	(462,647.13)
Deep	122	7,210.52	69,331.21
(last month)	(132)	(7455.52)	(81,970.71)
Ultradeep	78	16,176.40	41,688.00
(last month)	(79)	(16,191.40)	(41,748.00)
Total	1,061	56,467.64	534,974.34

Pipelines

(operational and 2015 onwards)

	(km)	(last month)
<8in.		
Operational/ installed	41,465	(41,457)
Planned/ possible	23,989	(24,400)
	65,454	(65,857)
8-16in.		
Operational/ installed	82,937	(82,961)
Planned/ possible	48,713	(48,031)
	131,650	(130,992)
>16in.		
Operational/ installed	93,986	(94,946)
Planned/ possible	44,457	(44,482)
	138,443	(139,428)

Production systems worldwide

(operational and 2015 onwards)

Floaters		(last month)
Operational	271	(270)
Construction/ Conversion	48	(49)
Planned/possible	301	(302)
	620	(621)
Fixed platforms		
Operational	9148	(9155)
Construction/ Conversion	88	(84)
Planned/possible	1351	(1351)
	10,587	(10,590)
Subsea wells		
Operational	4870	(4863)
Develop	381	(375)
Planned/possible	6355	(6351)
	11,606	(11,589)

Global offshore reserves (mmboe) onstream by water depth

	2014	2015	2016	2017	2018	2019	2020
Shallow	14,560.00	20,490.00	30,835.44	23,901.48	14,600.70	21,138.96	17,438.35
(last month)	(14,559.00)	(20,490.00)	(37,492.63)	(16,056.29)	(15,154.32)	(22,229.82)	(24,438.65)
Deep	4477.00	976.73	4847.45	2833.28	2585.84	4317.83	4849.48
(last month)	(4474.00)	(955.55)	(5090.04)	(2685.57)	(3232.20)	(5783.88)	(5115.43)
Ultradeep	2343 .00	1922.92	3141.08	2484.25	3674.65	4262.19	9964.21
(last month)	(2343.00)	(1922.92)	(3141.08)	(3190.03)	(4437.08)	(4942.40)	(7841.37)
Total	21,379.96	23,389.65	38,823.97	29,219.01	20,861.19	29,718.98	32,252.04

7 Jul 2016

Rig stats

Worldwide

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	104	68	36	65%
Jackup	398	251	147	63%
Semisub	127	87	40	68%
Tenders	31	21	10	67%
Total	660	427	233	64%

North America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	30	26	4	86%
Jackup	24	6	18	25%
Semisub	14	9	5	64%
Tenders	N/A	N/A	N/A	N/A
Total	68	41	27	60%

Asia Pacific

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	11	3	8	27%
Jackup	120	69	51	57%
Semisub	29	15	14	51%
Tenders	22	14	8	63%
Total	182	101	81	55%

Latin America

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	31	20	11	64%
Jackup	51	33	18	64%
Semisub	25	21	4	84%
Tenders	2	2	0	100%
Total	109	76	33	69%

Northwest European Continental Shelf

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	N/A	N/A	N/A	N/A
Jackup	48	38	10	79%
Semisub	40	33	7	82%
Tenders	N/A	N/A	N/A	N/A
Total	88	71	17	80%

Middle East & Caspian Sea

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	0	1	0%
Jackup	111	84	27	75%
Semisub	4	3	1	75%
Tenders	N/A	N/A	N/A	N/A
Total	116	87	29	75%

Sub-Saharan Africa

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	21	16	5	76%
Jackup	22	11	11	50%
Semisub	6	3	3	50%
Tenders	7	5	2	71%
Total	56	35	21	62%

Eastern Europe

Rig Type	Total Rigs	Contracted	Available	Utilization
Drillship	1	1	0	100%
Jackup	2	1	1	50%
Semisub	2	1	1	50%
Tenders	N/A	N/A	N/A	N/A
Total	5	3	2	60%

Source: InfieldRigs 13 July 2016

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

devices and gas lift, with gas-reinjection and water injection for pressure support.

In the latest incarnation of the development, the number of wells needed has been dropped from 40 to 31 and the number of templates from 15 to 10, plus two satellite, said Tore Karlsen, flowline manager Johan Castberg project, Statoil, at Subsea Valley. This means the number of risers has also dropped, from 18 to 11. All of which has reduced the length of pipe and umbilicals required to 116km, cutting materials and installation costs, as well as the number of rig days.

DC fiber future

A significant new element to Johan Castberg is its electric and communications infrastructure – in the form of new direct current fiber optic (DC/FO) cable technology. ASN, now part of Finnish communications giant Nokia, has been working on the technology since forming an agreement with Statoil in 2011-12, which Chevron has also supported. The goal was to design a solution incorporating high-bandwidth communications with reliable electrical power supply into subsea control systems, with "near-unlimited distances at any sea depth," says Håkon Frøyshov, principal engineer, subsea cables leader Johan Castberg project, Statoil. The result is an electrical and optical fiber infrastructure – separate from service umbilicals – to connect a production facility with subsea nodes, which can be placed inside or outside the subsea template, anywhere along the cable. The daisy infrastructure can feed 10kW downstepping the backbone high voltage to low voltage wet mate user interfaces, without any requirement for high voltage connectors, and wet mate direct fiber optic connection from the platform.

Depending on how it is configured, each node could serve 1-2 templates, or, to put it another way, at each node four electric outputs independent of each other can provide 2.5kW power, plus two fiber optic wet connectors. The nodes, which can will be controlled from the FPSO, have also been designed to have a standardized interface, to be independent of any subsea supplier.

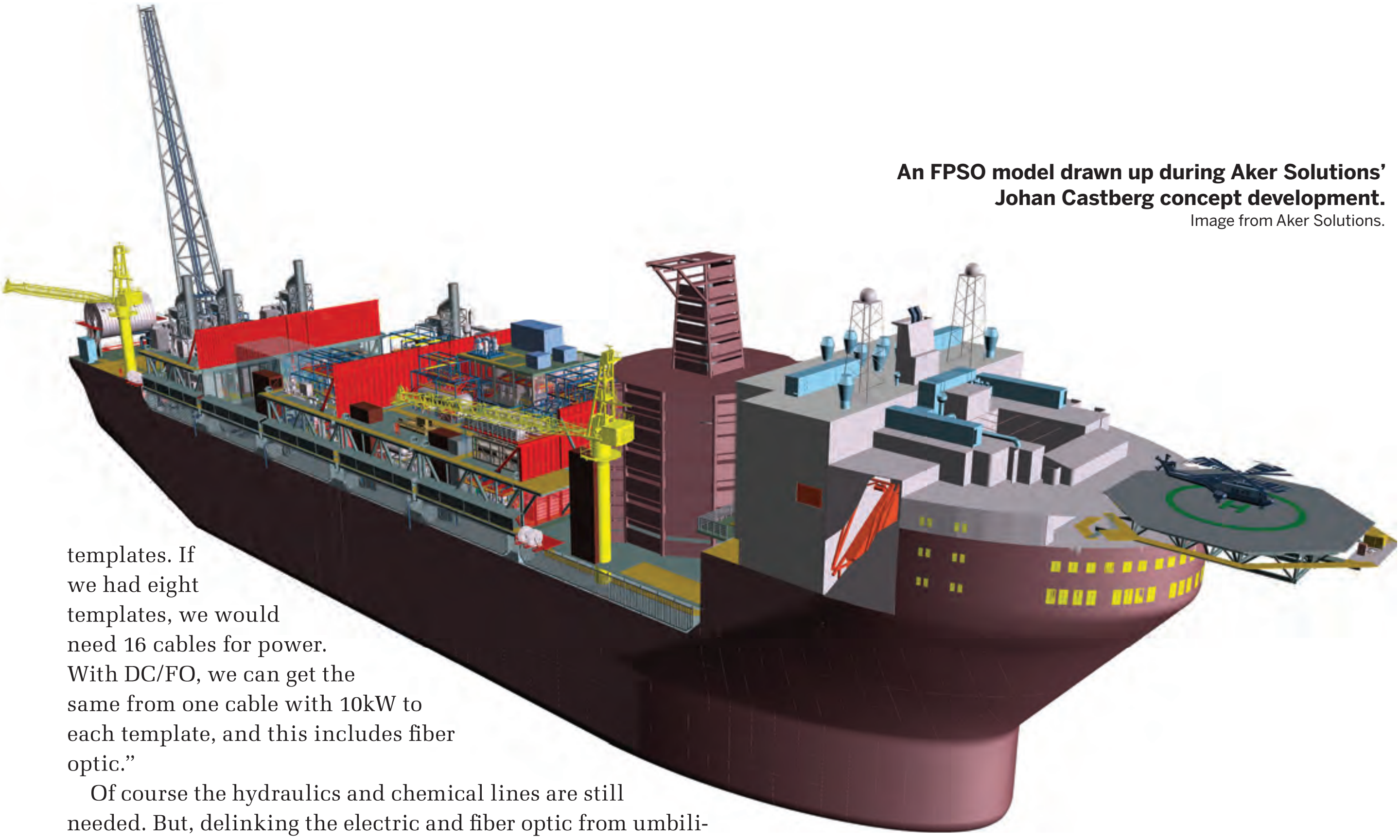
"They have a standard DC 400V interface, can communicate with any subsea control module on the market and can have optional inverters, to AC 220V, 400V or 500V," said Ronan Michel, O&G product line manager at ASN, at the Underwater Technology Conference (UTC) in Bergen this June.

The cable, which is in the final stages of qualification, is comprised of two electric conductors with fiber optic in the middle, and can either be powered by the production facility, or for long-distance step-outs, of up to 350km, with 100kW, Frøyshov says. The system may be equipped with more than eight nodes providing that overall system power (100kW) is not exceeded.

"The cable is fully repairable re-using standard telecommunications techniques that have been proven in 8000m water depth," Michel says. "Cable end boxes and Y-splices enable future tie-ins."

As well as extending cable length capabilities (current limitations are up to about 150km), the beauty of the design is that, on Johan Castberg, which would have had some 16 separate cables feeding eight templates, just two DC/FO cables will be needed, looping around the lot, Frøyshov says.

"Traditionally, one template, you would have two electric leads to provide electric power, each providing 1.5kW, for redundancy," he says. "For Johan Castberg, we have many



An FPSO model drawn up during Aker Solutions' Johan Castberg concept development.
Image from Aker Solutions.

templates. If we had eight templates, we would need 16 cables for power. With DC/FO, we can get the same from one cable with 10kW to each template, and this includes fiber optic."

Of course the hydraulics and chemical lines are still needed. But, delinking the electric and fiber optic from umbilicals means there's more space in the umbilicals, which also become cheaper and more reliable, just supplying hydraulics and chemicals, he says. It'd also be easier to make repairs to a DC/FO cable, being able to cut and splice sections, rather than having to replace whole hybrid umbilical cables, Frøyshov adds.

"The most vulnerable part in such a system is the electric," he says. "Hydraulic is more reliable, so you can put more templates in series. If you have damage, you can repair that in this system while leaving the hydraulics. It simplifies the riser base, as you don't need so many connections, and it makes installation easier. It simplifies the dynamic umbilical and you can have more flexibility in it as more space is available [for hydraulics, chemicals, etc.) so there is more future flexibility.

"There are other upsides too," including lighter topsides support equipment. "It's also an enabler for control functions for future tiebacks at least below 200km distance, i.e. there are no length limitations below 200km."

Add in electric-trees, which Statoil is moving towards and hoped to see within five years, another presenter told a session during UTC, and you have the potential for an even more simplified system. Indeed, Michel says, if you went all electric, all you would need would be the DC/FO cable and a chemical line – or use local chemical storage on the seafloor.

The DC/FO can be installed and ploughed within a single pass from a single and cost-effective standard installation cable ship. Rock dumping or mattressing are typically limited to e.g. pipe crossing. In addition, since the DC/FO is repairable from a standard maintenance cable ship, in areas where external risk aggression (e.g trawling) is limited, ploughing may be replaced by surface lay.

Flowline risk management

Karlsen's focus has been on simplifying the flowlines at Johan Castberg. It's a very irregular seabed, he says. Traditionally, this would mean all the production pipelines have to be protected by rock, which means excavation works and precise rock placement.

It's a huge cost, so Statoil took another look. "We started using a risk-based approach," says Karlsen, to both protection covers and rock placement. Using locking of inline structures on infield flowlines, not just on export lines, enables the removal of protection covers and reassessing the rock dumping regime reduces 70% of the cost for this work, he estimated. "This is in area with no trawling, so why cover non hydrocarbon carrying products? We don't have a total solution, but have road map and tool box now," he says. "This is what we call a design to cost way of thinking."

"The total saving today is NOK1 billion ($118.5 million). But we are not stopping there. We are using the tool box to ask if bigger pipe can protect smaller pipe," i.e. if something did trawl over the pipe, if a smaller pipe was laid next to a larger pipe, would its strength prevent damage to the smaller pipe. Furthermore, could residual curvature in the pipe be used and matched to the seabed?

The work is ongoing and is no doubt more comprehensive than what we can cover here. Indeed, there have also been discussions around whether Johan Castberg's FPSO, and therefore the subsea infrastructure, could be powered from shore. When it finally does get to project sanction, and first oil, Johan Castberg will be a further step for the industry into the Barents Sea, however.

What's more, developing Johan Castberg could mean infrastructure is in place for other nearby fields, such as Lundin Petroleum's Gohta and Alta finds. OE

FURTHER **READING**

Subsea power distribution for larger power consumers such as pumps and compressors are being developed. See page 20.

Power trip

Subsea power remains on the agenda for the subsea processing systems of the future. Elaine Maslin surveys the main players' progress in producing subsea power distribution systems.

The future of subsea processing systems based on long-distance step-outs has long been seen as a challenge.

For projects requiring power for pumps, booster stations or even compressors, etc., power has to be supplied from somewhere at a cost that doesn't inhibit the economics of the project.

Subsea power distribution, through a system able to deliver power to multiple users – pumps, compressors etc. – via one power cable to the subsea system, instead of needing separate cables to each user, has been seen as an enabling technology. It could help to increase step-out distances and reduce costs for medium-long distance tiebacks, as well as reduce topside space requirements.

The challenge has been to make subsea power electronics, controls, drives, etc., work in the subsea environment, up to 3000m deep. This includes switchgear, variable speed drives and controls, and auxiliary equipment. Switchgear systems enable many loads on one cable, for power distribution. The variable speed drives enable the pumps and compressors to vary their speeds—this is the biggest and most complex component—and the controls enable remote control and monitoring. The auxiliary equipment covers components such as power to magnetic bearings, instrumentation, etc.

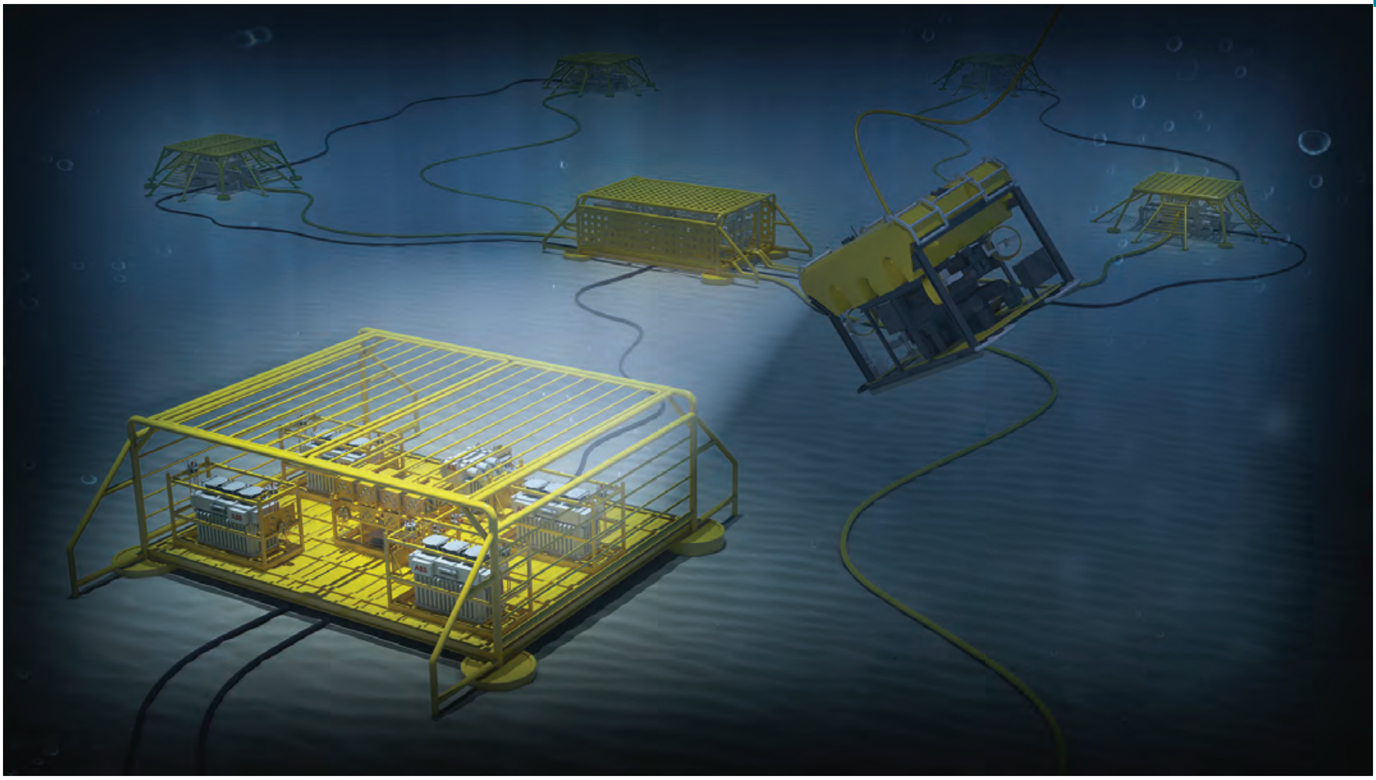
While subsea pumping, boosting and now compression (with a record 43km-long 18MVA, 120Hz step out at Åsgard), have been achieved, the rollout has been limited, in terms of the number of projects. To date, they have also relied on being connected to a topside's variable speed drives and switchgear. So far, only transformers and motors have been placed on the seafloor.

"Oil companies see the potential for subsea boosting and pumping, but they see the electric power system as one of the main costs, due to the cable costs," says Asmund Maland, alliance manager, ABB, on the ABB/Aker Solutions alliance, formed earlier this year. "If you can make a smarter solution, more projects will be realized."

"Building platforms and shipping people back and forth is very expensive," adds Jan Bugge, vice president and project manager of ABB and Statoil's subsea power joint industry project (JIP). "By putting equipment on the seabed you can use less power, because you are closer to the reservoir, and reduce operational costs. That's why this is important."

Qualified

GE Oil & Gas has a qualified system, after years of work on component, sub-assembly and full system testing for Shell's Ormen Lange subsea compression project. The system would transmit power from shore some 120km to Ormen Lange. GE says the system is based on known and understood surface components, which have been marinized in one-atmosphere



ABB's subsea power distribution station, an artist's impression. Images from ABB.

containers to be used on the seafloor.

While the project it was meant for was put on hold in 2014, GE Oil & Gas went through completion of the system, which successfully completed a 4000-hour testing regime late last year. This resulted in it being "the world's first system test incorporating a subsea switchgear and subsea drives."

Gilles Chene, senior sales manager, GE Power Conversion, outlined the project at the Underwater Technology Conference in Bergen in June. "For us, the project started in 2007. From 2009, testing started, followed by integration and, in 2011, submerged installation at Nyhamna pit [at Shell's plant]," he said. Testing has been running from 2012 to late last year, he said, amounting to some 4000 hours, including a 72-hour full load test.

The system incorporated a 20MVA transformer, switch gear unit, with 35kV circuit breakers and control systems, variable speed drive (VSD), a 12.5MW, vertically installed compressor and 500kW pump, and other auxiliary systems. The full load test ran with 10,100 rpm motor speed.

"The objective was to ensure a high speed drive could be created subsea," Chene says. "It exceeded expectations. The whole uninterruptable power system (UPS) proved reliable through the full campaign."

An "ultimate test" saw the system's fans switched off to test performance and this worked, Chene says. While the system was designed to operate without fans, using natural air circulation, it was seen that use of fans could prolong operational life.

A concern around subsea power supply from encased units has been the potentially limited information available as all elements are out of reach, Chene says. To mitigate this, a condition monitoring system was put on all units to provide measurements and run different data.

As qualified, the system could provide power to a hub, from which power could be distributed up to 20km out to 10 or more boosting stations, depending on power requirement, Chene says. "The final arrangement will be a tradeoff between size of modules, connectors, cable size and size of the units," he says.

The aim now is to build on this technology to develop a far more compact system, looking at the different materials that have become available since the project started in 2007, as well as progress in power electronics, but also because this system was designed for use with a large compression project. "For us now it is about industrialization, not changing the technology," says Kristin Elgsaas, senior product manager, GE Oil & Gas. "Changing the configuration so it is easier to assemble and reduce risk."

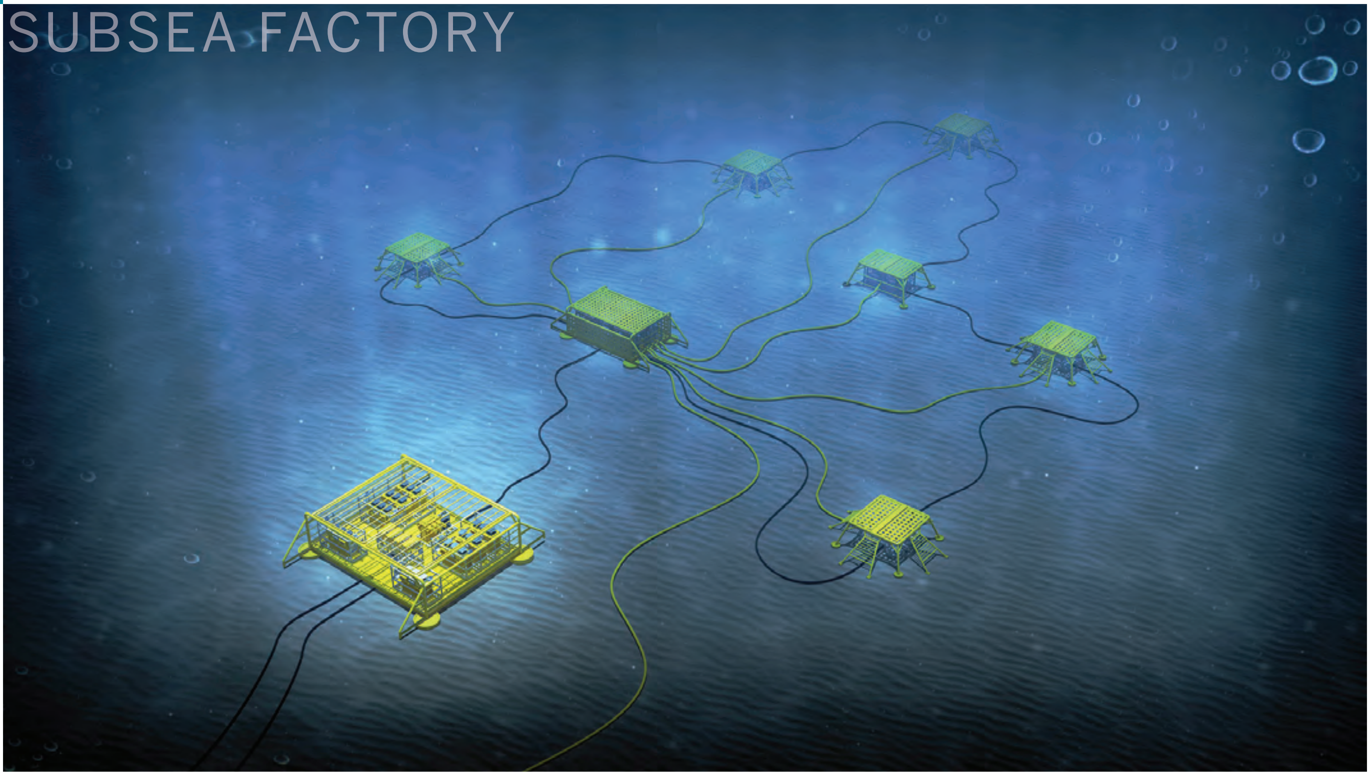
On show

ABB also has a full system ready – in model form for show at least. The firm is working on a US$100 million JIP with Statoil, signed in 2013, to qualify a system able to transfer 100MW over up to 300km in up to 3000m water depth. Chevron and Total are also partners.

ABB will have a scaled 3D model of the system it is working towards qualification on at its stand during ONS in Stavanger this month [August].

Bugge says that the JIP is going well. ABB is putting its components in pressure balanced oil-filled containers, so that they can withstand the pressures at 3000m water depth without large, thick containers and make use of cooling mechanisms using the oil. "Reliability is key," he says. These components need to live and operate reliably at 3000m water depth for years.

Currently, the large power and automation firm is working on qualifying components, including the power cells, which will form part of the variable speed drives. ABB will then start building the first prototypes this year. Full system testing, covering 3000-hour testing, is due in 2018. Market



The subsea factory – as envisioned by ABB.

application is most likely after 2020.

"We are working on the building blocks, [such as] circuit breakers, which go into the switchgear, and then building the first prototype switchgear towards next year. In the same way, we are building up components for the power cells for the subsea drives."

Testing on the first drive will be done in Finland, where all the shallow water tests for the transformers have already been completed.

"The variable speed drive is complex," Bugge says. "It is built from key power electronic components, power transistors, and has to be able to handle large power." Indeed, there's a lot of detail across the whole project. "And that's what we are discussing with customers as we speak," he says. "It's hundreds and hundreds of tests." Maland also highlights detailed work being done around software to enable the switchgear to provide a smooth power supply to users.

While investment appetite is low currently, due to the low oil price, there's no reduced appetite for the work ABB is conducting on subsea power, Bugge says. "Oil companies are focusing on what's closer [nearfield exploration and tie-backs]," he says of the current climate. "But, new technology is required and new technology will enable different ways to get resources out of the ground. The very long step-out is a natural step. In the depressed economy, the focus is on what's near but it [long step-outs] will definitely come, and with it the need for new equipment at the seabed."

Earlier this year, ABB and Aker Solutions formed an alliance that will see them pool forces in this area. "One of the key areas is subsea boosting as well as subsea compression project," Maland says. "ABB and Aker have complimentary technologies. They cover hardware for subsea production equipment and ABB is mainly in the power space but also control and automation."

On something like subsea compression, Aker Solutions would be and is looking to reduce the equipment footprint, while ABB will look at how electrification can be optimized so it's ready for new projects.

Siemens

Siemens is also working on a subsea power distribution system, which it calls Siemens Subsea Power Grid (SPG), since 2010, alongside a joint industrial partnership program with selected oil majors.

The firm says all major design and engineering work is in its final phase and that its current focus is on final assembly and testing at its purpose-built Siemens Subsea Technology Centre in Trondheim, Norway.

Siemens' subsea transformer was qualified with a full load shallow water test in 2012, and is currently being commercialized. Siemens' subsea adjustable speed drive and subsea switchgear are being assembled and tested successfully. All main units will run through a system integration test in the factory in early 2017, with a plan to perform a full load system test in water during summer 2017.

"More than 80 engineers are currently working on this major development program, which has allowed Siemens to file for more than 120 patents," says Patrick Brandmaier, head of Siemens Subsea Systems. "The substantial investment and competence build-up has allowed the launch of further programs successfully, with industrial partnerships in related areas of technology such as subsea power and subsea control." OE

FURTHER **READING**

An alternative simplified power distribution system, one which doesn't have to power pumps or compressors, has been developed by Alcatel Lucent and is set to be used on the Johan Castberg project. Read more on page 16.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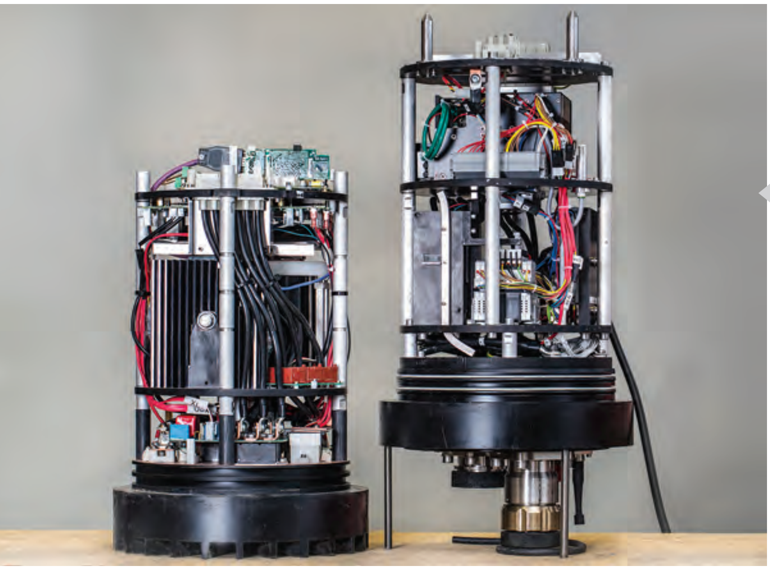
Small and smart



The 45kW subsea variable speed drive. Photo from Nebb Engineering.

Power requirements are not always huge, nor are companies – and sometimes smaller can be better. Elaine Maslin reports on work to qualify lower power subsea variable speed drives.

Norway's Nebb has its eye on a market the larger players are overlooking – subsea variable speed drives (VSD) for power users requiring smaller amounts of power than the likes of compressors.

To date, subsea VSDs, used to regulate the speed and rotational force of an electric motor, have only been deployed once, in a pilot at Shell's Nyhamna plant in Norway. These were designed for the large Ormen Lange subsea compression system, which Shell put on hold in 2014.

Yet now, Nebb Engineering, based in Asker, near Oslo, has qualified a 45kW subsea VSD, for operations down to 3000m, and is now working on VSDs for the 4kW and 350-1500kW ranges.

While 45kW VSDs wouldn't be quite big enough for the likes of a subsea compression project, they could be used to power actuators or small pumps. Using electric power transmission, instead of hydraulic, for subsea power users, removes the need for hydraulic power units and topside VSDs, in cases where electric power is supplied direct from the topside to seafloor users.

Nebb's 45kW, 400V VSD was in part developed for a project with Kongsberg Oil & Gas and Fuglesangs, to develop an active subsea cooler, to cool production fluid for export or compression, and which could be controlled to prevent hydrate formation. This project was due to complete full qualification this summer. The system comprises a heat exchanger, a pump, from Fuglesangs, which incorporates an oil-filled motor isolated from the pump by a magnetic couple, and a control system, all for use up to 3000m water depth.

Nebb's part of the project was developing the control system and communications including the 45kW subsea VSD, which is contained in a 1053mm high, 356mm-diameter canister. This system could have been used on Shell's Ormen Lange project, until it was put on hold in 2014.

A 20-45kW VSD could also be used to power medium sized pumps. Meanwhile 300-1500kW VSDs, could be used for electrical submersible pumps (ESPs), water injection or condensate pumps. This size VSD Nebb hopes to have ready in 2017. The 4kW VSD, due to be qualified this year, contained in a 450mm-high, 210mm diameter canister, could be for use on small pumps (for grease, hydraulics etc.) and valve operation (from remotely operated vehicles). They could also be used in brownfield applications by incorporating a battery pack, that Nebb also has in development.

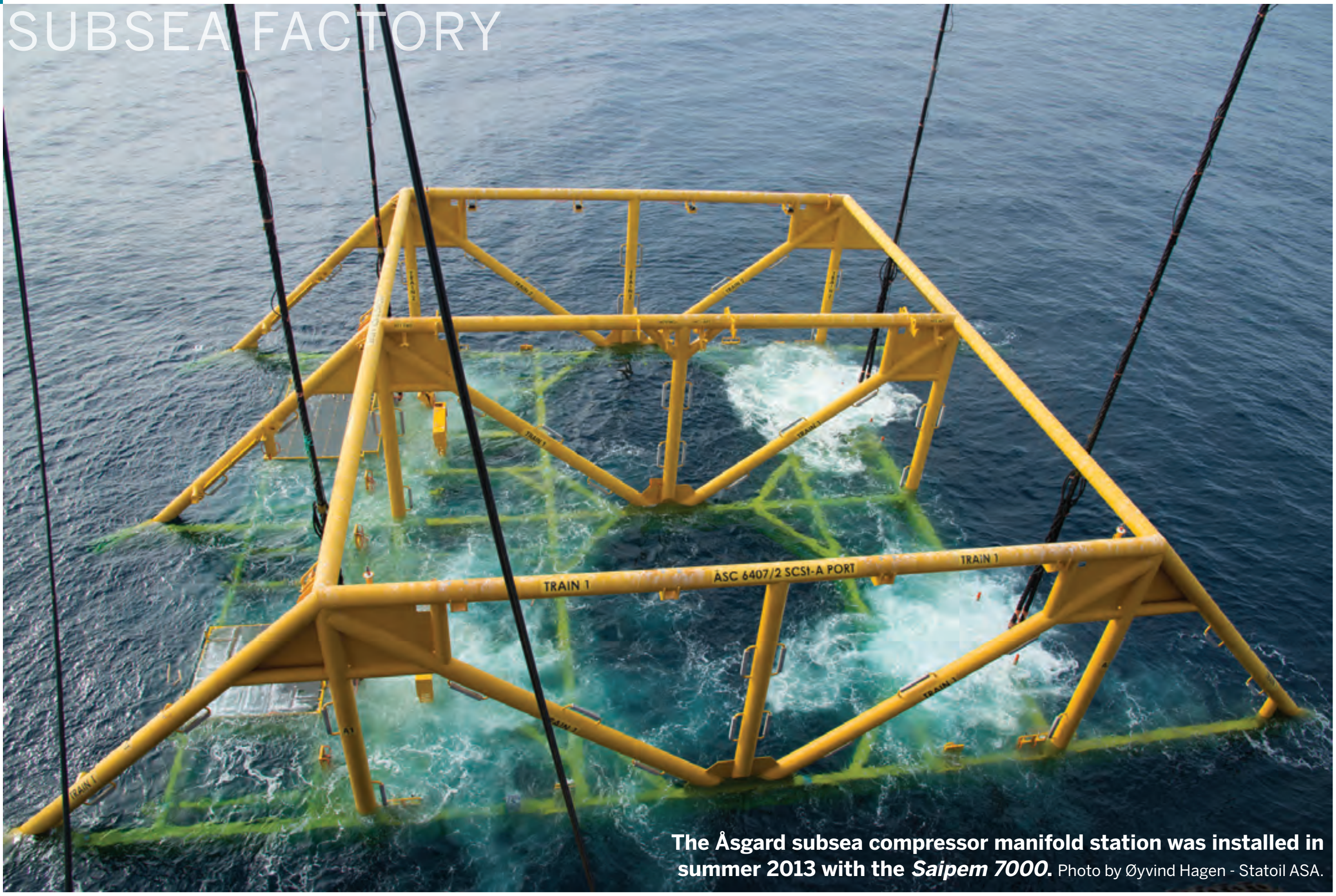
Alexander Risøy

"This is an enabler for all electric subsea control," says Alexander Risøy, managing director at Nebb Engineering.

One of the main challenges is to get rid of the heat, he says. "On a 45kW VSD you need to get rid of 1.5kW heat and keep it below 35°C to extend the life time." This is Nebb's secret and they're not willing to say how they do it. "It is difficult, but possible to do," says Wolfgang Trötscher, chief engineer. "It is even more difficult with 500kW unit, which produces 5kW heat."

Nebb's goal is a 1MW VSD, for which there would be a larger market than say a 500kW VSD. For this, the firm will be looking to work with oil majors.

The company was founded in 1996, and has about 40 staff, with an office in Macedonia. It also provides automation control and safety systems, SCADA and information management, as well as subsea control modules. OE



The Åsgard subsea compressor manifold station was installed in summer 2013 with the *Saipem 7000*. Photo by Øyvind Hagen - Statoil ASA.

Down but not out

The oil price crash brings subsea processing opportunities, says Rystad Energy's Jon Fredrik Müller.

There have been few subsea developments sanctioned over the last year due to the falling oil prices. With oil prices currently in the US$50/bbl range, sanctioning activity is still moving slowly. Cost compression and re-engineering of previously planned concepts are lowering breakevens of many projects, towards levels that could warrant sanctioning. Although Rystad Energy believes in a strengthening of the oil price towards 2020, we still see few offshore projects sanctioned this year. However, we do see an increasing interest to discuss possibilities for subsea processing. Especially subsea boosting and compression solutions, which could bring additional volumes from existing fields in a profitable way, have recently received increased focus from the operators.

Of the different kinds of subsea processing, it is subsea boosting that has matured the most. The main advantages of subsea boosting are accelerated production, increased production and recovery, and development of low energy reservoirs, heavy oil fields, long tiebacks, and other fields where pressure differentials might be an issue. The first subsea booster pump was a twin-screw multiphase pump developed by GE Oil & Gas, which was installed on Eni's Prezioso field in Italy in 1994. Although GE was first, it is OneSubsea (through Framo Engineering) that has become the market leader with their helico-axial pumps. Today, several different solutions for subsea boosting have been installed, or awarded. Currently, the portfolio of projects count close to 40 fields around the globe, see figure 1.

Conventional subsea boosting solutions have often involved large topside structures like variable speed drives (VSDs). For brownfield applications, the need for topside equipment have in many instances resulted in potential subsea boosting projects being shelved, due to limited topside availability. However, new technology developments will likely reduce the need for topside equipment, or almost remove it all together. Several developments point in this direction, like developments of subsea booster pumps with integrated VSDs, like Fuglesangs Subsea is developing, or marinization of equipment that is normally put topside. There are also ongoing developments on smaller booster pumps, optimized for boosting single well streams. These solutions will likely increase the number of fields applicable for subsea boosting. These pumps could be configured as a traditional booster pump, but there are also developments integrating the boosters into flowline jumpers, as Aker Solutions and Baker Hughes have done.

Another subsea processing technology that could increase production from producing fields is subsea compression. Traditionally, producing gas fields with need for compression have installed gas compressors on an existing platform, or built a new platform. By taking the compression subsea one can reduce the need for additional platforms and place the compressor close to the well, which increases the effect. However, subsea compression systems are complex and require large gas resources to justify the investments.

Currently, there are two subsea compression systems in operation, a dry gas compressor at Åsgard and a wet gas compressor at Gullfaks South, both Statoil operated fields. Aker Solutions

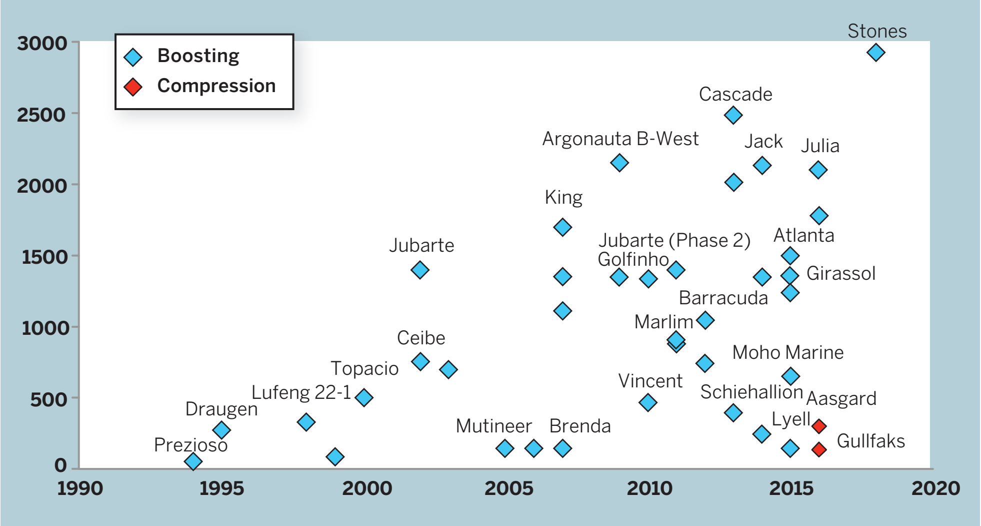
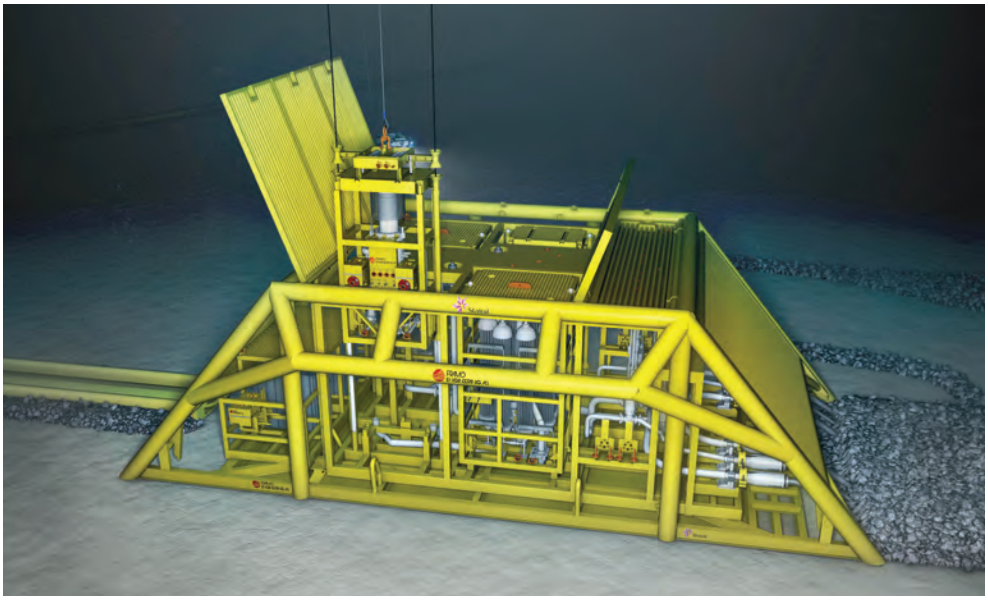


Figure 1: Subsea boosting and compression projects by water depth (meters) and installation year. Source: Rystad Energy.



An illustraton of the the wet gas compressor meant for the Gullfaks South subsea factory.
Illustration from Statoil.

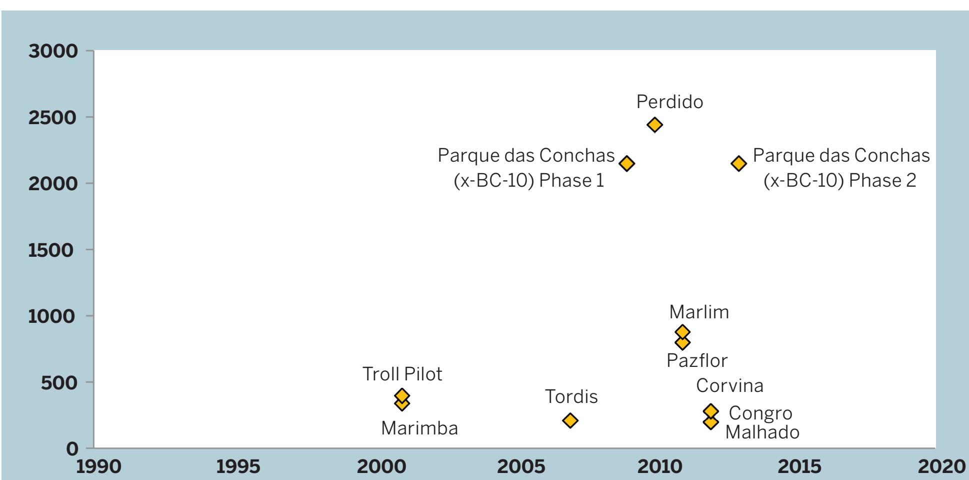


Figure 2: Subsea separation projects by water depth (meters) and installation year.
Source: Rystad Energy.

delivered the Åsgard project, which includes pre-compression separation, while OneSubsea delivered the system for Gullfaks South. The Gullfaks South project has had some initial problems, but the Åsgard system has so far run like clockwork. Although somewhat costly projects, part of the costs should probably be allocated to research and development, and thus, future systems are likely to be considerably cheaper.

Subsea separation is the concept of separating gas/liquids or oil/water at the seabed, and might in some instances be a prerequisite for other subsea processing systems. Many of the applications so far have been in conjunction with subsea booster pumps, and subsea separation is today a proven technology. While OneSubsea has taken the largest share of the booster market, it is FMC Technologies that has become the market leader in the separation segment, being system provider on the majority of projects completed, see figure 2.

Booster pumps are mainly used on oil fields with low gas to oil ratios, both for heavier and lighter crudes. The key regions have been, and will continue to be, Brazil, the US Gulf of Mexico, the North Sea and West Africa due to the water depths, reservoir characteristics and tie back distances. Subsea gas compression projects require somewhat larger resource base than the booster pumps, in order to be commercial. Key regions for this technology over the next coming years will likely be the North Sea, Australia, East Africa and the Mediterranean. Subsea separation systems have now been installed at 11 fields operated by Petrobras, Statoil, Shell and Total. All the fields lay in Brazil, Norway, US GoM or Angola, and going forward these areas, including the rest of the North Sea and West Africa, are seen as the primary markets for such systems.

Considering the number of subsea fields (~1500) compared to the number of subsea boosting (~40), compression projects (2) and subsea separation (11) systems, the current technology adoption is low. The main reasons for this are related to costs, uncertainty regarding reliability (proven on boosting and separation by now), and a general conservatism in the industry. In the current low price oil environment, we have seen clear signs that operators are looking into how to increase the production from existing fields to improve cash flows short/medium term. In some instances, the operator may prioritize such projects, over greenfield developments, due to a lower overall capex and time to production. Due to this, the current downturn may yield an increase in subsea processing projects for brownfield applications. Brownfield processing could be some of the more interesting projects before greenfield sanctioning picks up with an estimated recovery in the oil price towards 2020. **OE**

Jon Fredrik *joined Rystad Energy in 2010. Before that, he worked as a consultant at Accenture. His area of expertise includes strategy and market assessments, macro analysis, transaction support and valuation for upstream E&P, oilfield services, financial institutions and governments. He holds an M.Sc. in Industrial Economics and Technology Management from NTNU, Norway and participated in a graduate exchange program at the Haskayne School of Business, University of Calgary.*

Charting Subsea Processing

Quest Offshore provides a look at subsea processing systems by type.

Subsea Processing Project List (Onstream 2010+)

Subsea Processing Application	Region	Operator	Project
Boosting	Africa/Medit.	Murphy	Azurite
Boosting	South America	Petrobras	Espadarte-22 (Pipa-2)
Boosting	South America	Petrobras	Golfinho Mod 3
Boosting	South America	Petrobras	Jubarte 2 (subsea tieback to P-57)
Boosting	South America	Petrobras	Barracuda
Boosting	North America	Petrobras	Cascade Chinook
Boosting	South America	Shell	Parque das Conchas Ph 2
Boosting	Africa/Medit.	Total	Girassol Resource Initiative (GirRI)
Boosting	Africa/Medit.	Total	CLOV
Boosting	Africa/Medit.	Repsol	Montanzo-Lubina
Boosting	North America	Chevron	Jack St. Malo (JSM)
Boosting	North Sea	Shell	Draugen Multiphase Boosting
Boosting	Africa/Medit.	Total	Moho Phs 1 bis
Boosting	South America	Petrobras	Whale Park N (Parque das Baleias)
Boosting	North Sea	BP	Schiehallion (Quad 204)
Boosting	North America	ExxonMobil	Julia
Gas Compression	North Sea	Statoil	Asgard Gas Compression
Gas Compression	North Sea	Statoil	Gullfaks South Gas Compression
Separation & Boosting	North America	Shell	Perdido
Separation & Boosting	Africa/Medit.	Total	Pazflor
Separation & Boosting	South America	Petrobras	Marlim

Source: Quest Offshore

The Solan facilities with the *Bibby Polaris*. Photo from Bibby Offshore.

Tanked up

The Solan subsea tank prior to installation. Photo from Atkins.

Subsea oil storage solutions could help unlock marginal fields; how easy would it be? Elaine Maslin reports from a workshop that assessed the issue.

How to tackle the North Sea's small pools – discovered fields containing under 15 MMbbl – has been under sharp focus in Aberdeen.

According to a study, there are 210 "small pools" of hydrocarbons on the UK Continental Shelf, totaling some 1.5 billion boe.

A hunt is on to find economic ways to produce these deposits and for some the answer lies in producing fields without the use of umbilicals to topsides facilities or even export pipelines (*OE*: December 2015, "Cutting the Umbilical").

Producing power on the seafloor (to power subsea equipment) and wireless communication for controls (via a buoy at the surface) are seen as being feasible, if not already proven. Subsea chemical injection solutions are also being worked on... But, how do you get the produced fluids to market?

Subsea storage is an option and the topi was the subject of a one-day workshop run by the National Subsea Research Institute (NSRI) near Aberdeen.

History

For some, it's a proven concept. There are examples in the North Sea and elsewhere, including the Prinos oil field, offshore Greece, and the 500,000 bbl Khazzan subsea storage tanks. The latter were installed 60mi off Dubai in 154ft water depth in 1969, to store oil from the Fateh field. Both are still operating.

"Over the last 40 years, subsea storage tanks have figured into [North Sea] oil and gas production," said Graham Whitehead, field development manager at EnQuest and a part of the UK's Technology Leadership Board's small pools team, during the NRSI event. "In 1978, Thistle was storing oil in the steel legs of a jacket, with export of crude over a SAL (single anchor loading assembly), because there was no infrastructure in place at the time. The Brent pipeline was still being built. Other examples in the 1970s include Kittiwake. It was the first asset that had subsea storage over the platform base."

There was also Harding in the mid-1990s; Siri, in the Danish sector, in the late 1990s, and most recently, Premier Oil's Solan. "That is excluding gravity-based structures and big concrete structures, or spars," he says.

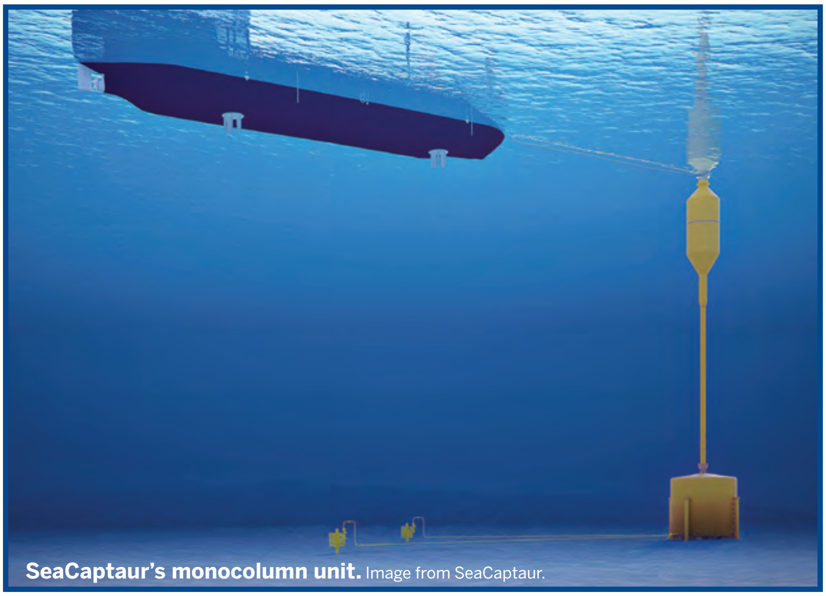
The two main drivers for use of subsea oil storage have been remoteness and a lack of oil export solutions, Whitehead says. But, other reasons could include field size, and fluid and field complexity – Harding produced a fairly heavy oil and it wasn't possible to just put it in a common network, he says – as well as the succession plan for when existing infrastructure becomes too costly to operate.

Most recently, Premier Oil used a steel subsea oil storage tank on its not normally manned Solan facility, west of Shetland, as a way of compensating for the lack of infrastructure in the area. The Solan subsea tank is a beast, using 10,000-tone of steel, and measuring 25m-tall, 45m-wide, and 45m-long, with a capacity of about 300,000 bbl. The tank features a honeycomb of small chambers, containing anodes, to ensure integrity as waves pass over and to prevent corrosion on the steel, the event heard. Biocides and biopenetrants will also be used to prevent corrosive bacteria and marine life from forming. The tank is offset from the steel jacket-supported platform and connected by flowlines. Premier's initial plans estimated that tanker offloading will occur every 7-10 days, taking 24-36 hours each time.

Scaledown

However, something the size of the Solan tank, which was fabricated in Dubai, would not be needed or economical for a "small pool." More crucially, most subsea tanks, to date, have been for use with processed fluids. Storing unprocessed fluids offers significant challenges.

Considerations for subsea oil storage designs for small fields include fluid co-mingling, differential pressure in the tank, gas dispersal on fields with gas content, slugs dispersal, low energy fields and dealing with corrosive fluids, Whitehead says.



SeaCaptaur's monocolumn unit. Image from SeaCaptaur.

Steve Howell, technical director at Aberdeen-based engineering simulation firm Abercus, suggested the storage process could be used to settle out multiphase fluids – as a crude separator. But, he says, some processing would likely still be needed and if water ballasting is used to even out the differential pressure during filling and periodic offloading, then flow assurance issues would need to be addressed in case emulsions form.

Others issues raised include how to handle produced gas and water. Water could be handled, potentially, through treatment and re-injection, but gas separation and handling remains a primary technology challenge, according to a post-event report. Depending on the fluids, it could also be that the tank would have to be heated to prevent wax or slurry formation.

One potential solution was to have tank farms. David Sinclair, engineering manager, Bibby Offshore, suggests, for small pools, having several small tanks, which would be easier to fabricate and install and then recover for offloading or reuse.

"With quicker decline rates on small pools, they could also be designed to be recoverable for reuse elsewhere," Sinclair says, using construction support vessels instead of heavy lift vessels. It would also mean local fabrication could be easier, with fewer issues relating to concerns around internal integrity, he says. This could also mean decommissioning would be easier than it has been for some of the large existing storage tanks.

Gordon Drummond

A new business model?

Such a concept could offer the potential for a new business model. Part of the problem around small pools is that they are small and fairly widely distributed, so that not one operator has "enough skin in the game" said Gordon Drummond, NSRI manager.

Designing one and building many would enable standardization and simplification, he suggests. Having a subsea tank as a business akin to shipping containers may also address unprocessed fluids, moving the problem from subsea to onshore where it can be cheaper and easier, albeit it is accepted this would lose the benefits of processing closer to the reservoir and would mean transporting at least some product with little or no value.

Membrane

Norway's Kongsberg has been designing a solution – the Kongsberg flexible storage unit. It would store part-processed oil within a flexible membrane, inside a protective structure, providing a double barrier with integral leakage control and monitoring, says Astrid Kristoffersen, vice president subsea products.

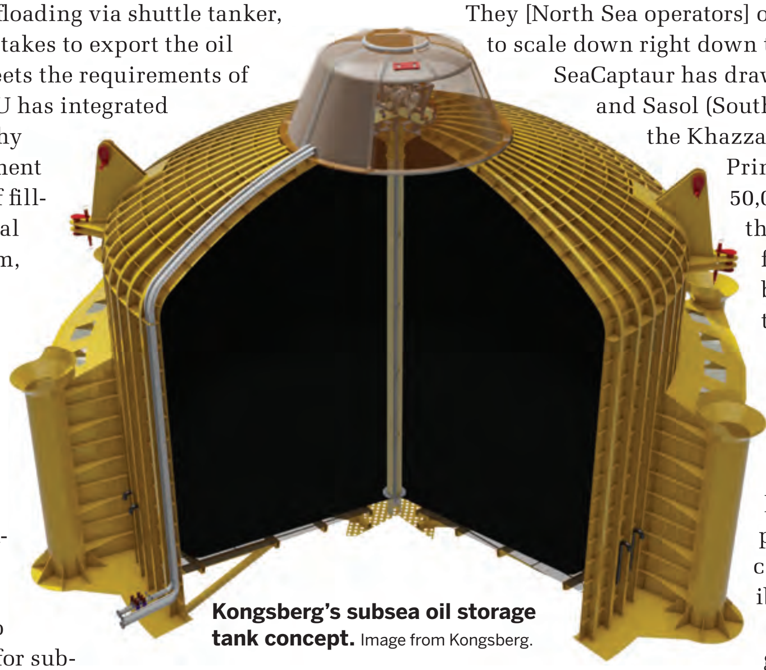
The flexible membrane helps overcome differential pressure concerns and also prevents emulsion layers from forming, he says.

The flexible bag would be made from a coated fabric membrane with a hatch at the top with an inlet and outlet. The bag, containing up to 150,000 bbl in a reference case, is attached to the top and bottom of a center pipe, and both are inside a ballasted solid protection structure, into which seawater is allowed to flow, filling or exiting the structure, never in contact with the oil. The bag and center pipe can be retrieved.

Kongsberg designs the SSU (subsea storage unit) system from the riser, from a topsides facility where it has been through separation, to offloading via shuttle tanker, to ensure that the time it takes to export the oil and heat management meets the requirements of the specific field. The SSU has integrated sensors, barrier philosophy and operational management ensuring full overview of filling, discharge and thermal performance of the system, says Kongsberg.

The project was given Demo 2000 funding and is part of a joint industry project with Statoil, Det Norske, Lundin, and the Research Council of Norway. As part of the DEMO 2000 funding, testing was carried out on a 1/9 scale model.

Kongsberg is looking to offer similar technology for subsea chemical storage and produced water storage.



Kongsberg's subsea oil storage tank concept. Image from Kongsberg.

Seacaptaur

Australian firm SeaCaptaur has another solution. Alan Roberts, the firm's managing director, and Max Begley, of Matrix Composites & Engineering, joined forces to create a system to develop small pools.

SeaCaptaur is focusing on fields containing 5-15 MMbbl recoverable in 10-300m water depth. Roberts says there're around 2000 small pools around the world, but to develop them at US$50/bbl you need a solution that has 50% of the capex and opex cost of present day FPSOs (floating production, storage and offloading vessels). SeaCaptaur thinks the North Sea has the most potential in terms of producing its small pools. But, Roberts says, "there's a cultural problem. They [North Sea operators] only understand big. They need to scale down right down to small and basic."

SeaCaptaur has drawn on the Apache (Australia) and Sasol (South Africa) control buoy systems, the Khazzan oil storage tanks and the Prinos tank. It has a base case 50,000 bbl oil storage tank on the seafloor. The tank would be floated out using a tug and then ballasting for positioning. The tank would be connected, using tethers, to a rigid monolithic production spar buoy, which pierces the surface for gas flaring and offtake.

The buoy would contain four levels, or decks, containing the processing systems – which could support electric submersible pumps. Access for maintenance would be via an access gangway, the like those being used in theoffshore wind industry.

The system would require a specialized, 65,000 bbl capacity shuttle tanker for offtake. SeaCaptaur has designed a DP shuttle tanker for this job, complete with motion compensated gangway, which could in effect do a milk round of several facilities and take the crude straight to the terminal, to avoid third party lifting charges or tariffs.

"It is still cheaper than a FPSO," but, you have to have a number of small pools running, say 2-3, to maintain a production rate of 10-11,000/d, to make it work, Robert says. OE

Relying on infrastructure

While there is a large prize to be had in the UK North Sea's small pools, individually it's hard to make these small reservoirs pay their way.

According to a University of Aberdeen report looking at the possible profitability of small pools (containing 3-15 MMbbl recoverable), at $60/bbl, the smallest size pool that becomes economic is 11 MMbbl.

The current technology to develop such a field is a single well, with a single flowline, a single umbilical for tieback to a host. But, "if we could cut the cost by 25%, it would take the field size to 9 MMbbl. If we could reduce it by 50%, it would be 6 MMbbl," says Peter Blake, chairman of the National Subsea Research Institute, part of Subsea UK. "Obviously we are not operating in a $60/bbl world, it is $42 today [at the time of the NRSI event in April]. There is a considerable challenge to get capex down if we want small pools to be developed."

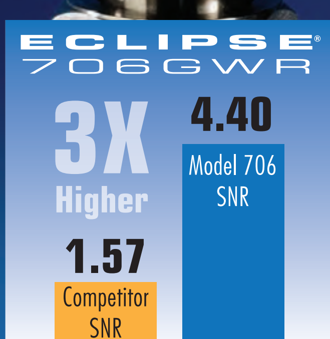
Another study, by the UK's Oil and Gas Authority, found that many of these small pools are tantalizingly close to near infrastructure, however. Many of the pools containing less than 50 MMbbl, are within 50km of a pipeline – although what type of pipeline this was needs defining in further work. Some 80% contained less than 20 MMbbl but were less than 10km from a pipeline.

Peter Blake

By far, most of the opportunities are in the central North Sea, followed by west of Shetland and then the northern North Sea. "The central North Sea and northern North Sea is where there is already a lot of infrastructure," Blake says. "There is not a lot of infrastructure west of Shetland."

"There is a possibility to hook this stuff into other things or hook it together," Blake says. "The scope for standalone infrastructure isn't as big as expected." But, "there is [also] a valid concern this infrastructure could disappear. In this environment can subsea storage be competitive and what does the overall system around that system look like?" And it's not just a UK North Sea opportunity. Blake thinks subsea storage could be used in shallow water basins elsewhere around the globe. "But it cannot be technology for technology sake, it needs to be at a price that can make developments happen."

break through the NOISE



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A joint industry project to reduce the time and effort spent on documentation around subsea projects has given the industry food for thought. Elaine Maslin reports.

Photo from iStock.

Paper shredding

"Subsea documentation has really hit a nerve," says Bjørn Søgård, segment director, subsea and floating production, oil and gas, business development, DNV GL.

Work by DNV GL under a joint industry project (JIP) looking into the documentation shared during subsea project engineering revealed some staggering numbers.

Between 2012 and 2015, subsea documentation increased by a factor of four, according to one contractor. Previously, a contractor in a typical subsea project would delivery around 10,000 documents, with each one averaging three revisions, resulting in up to 30,000 transactions between two actors. Today, projects can deliver 40,000 documents, with three revisions resulting in 120,000 transactions. Handling time has also doubled per revision.

The result is cash, in staff and time. The JIP addressed the issue by looking at what documents were necessary and what added cost without adding value. The idea, which resulted in a recommended practice (RP), is to define what needs to be shared, and what doesn't, and where some documents can be standardized.

One JIP participant thinks that by adopting the subsea documentation RP, a 42% reduction in engineering hours could be delivered, by reducing reviews through reuse of documents and having more standardized documents and avoiding unnecessary reviews on non-critical documents. Another member of the JIP thought up to 70% reduction in amount of documentation could be delivered.

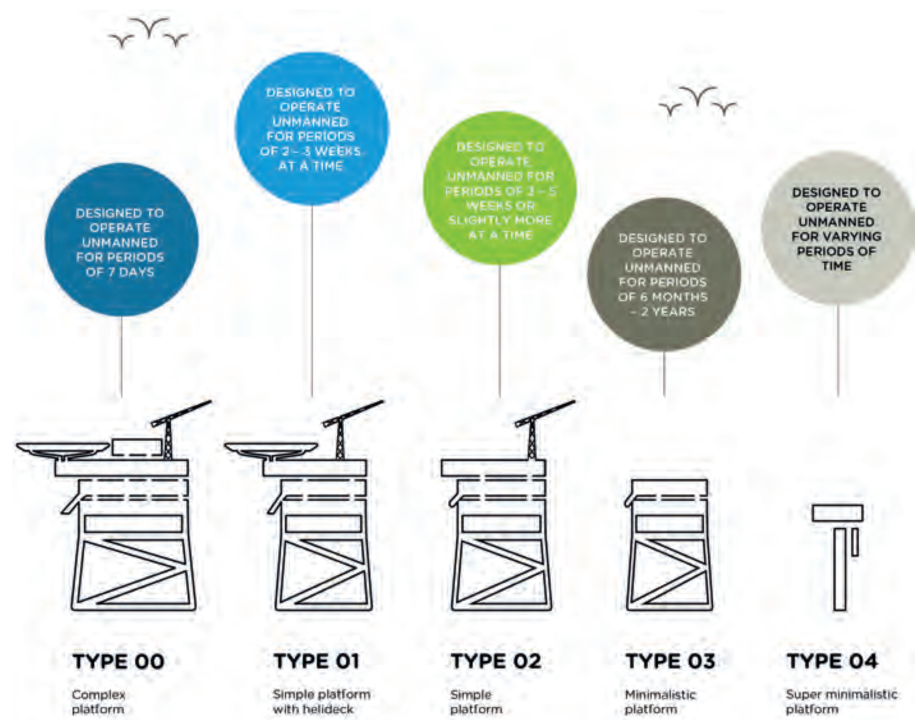
A draft version of the RP was used on Statoil's Johan Sverdrup project last year. The Norwegian oil major leaned heavily on companies to comply with the RP or leave, says Roald Sirevaag, project manager for subsea standardization, boosting and compression, at UTC Bergen. "It is a sign of what we are achieving," Søgård says. "And, it is getting more attention than we had at the start. This industry had become expensive and inefficient. You have lots of documents shared between vendors and buyers and quite a few are 'for information' and quite a few for review. The buyer sends back the review documents and the vendor updates them accordingly. But the trend had become that documents for information only were also being red-lined and required updating by the supplier. This was adding complexity." Everything is done for the best intention but, what was happening, he says, was that although the market was growing, costs were also growing 15% year on year. In a growth period this creates more talent mobility in the market and as staff turnover increases, reducing the number of staff with knowledge of projects, which continues the cycle.

Another factor driving cost in this area has been operators adding their own requirements on top of the routines vendors were already working to, including welding procedures, forging systems, etc. In the maritime industry, this isn't such an issue as buyers trust the yards thanks to governance procedures established by the class societies. Maritime suppliers making components know how they need to be made and how quality will be assessed," Søgård says. "This isn't the case in the offshore industry. We need greater governance and trust."

The industry is taking the RP on board, however, he says, and DNV GL is also looking to take it over to the UK sector, where it is in discussion with the Efficiency Task Force, a group set up to drive efficiencies like subsea documentation standardization. OE

Less is more

Unmanned facilities are being given serious consideration offshore Norway. Elaine Maslin reports.



Minimal facilities scopes. Image from Ramboll.

For some regions, unmanned facilities are the norm. The southern North Sea – off Denmark, the Netherlands and the UK – is strewn with them, for example.

Yet, in the same basin, they're a little bit anathema. For Norwegian operators, the choice seems to be one between a manned facility and a subsea development. Until now. Last year, faced with wallet busting subsea development costs, Statoil opted for a remote controlled unmanned wellhead platform for the Vestflanken 2 project at Oseberg.

Earlier this year, the Norwegian Petroleum Directorate (NPD), which has welcomed Statoil's move at Vestflanken 2, commissioned a report from engineering house Ramboll on unmanned facilities. The report says that unmanned platforms can be cost- and production-efficient development concepts in shallow water on the Norwegian shelf.

For the NPD, unmanned facilities could be a solution for shallow water marginal fields. Here, a minimal-facility would act as a satellite platform tied back to a host installation, with power, chemicals, utilities, signals and controls typically supplied by the host via an umbilical. The benefits, it says, are reducing initial capex, in terms of facilities cost, but also installation costs and opex.

Track record

In the North Sea, there are already more than 200 unmanned wellhead platforms, dating back to the 1980s, according to Ramboll, which has designed many unmanned and minimal facilities platforms for the southern North Sea as well as the Gulf of Mexico and Middle East. Some 148 of the 200 are in the UK sector (which has 590 platforms in total), mostly in the southern North Sea gas basin in 20-150m water depth. Some 14 are offshore Denmark and 47 are in the Dutch sector, in 20-70m water depth.

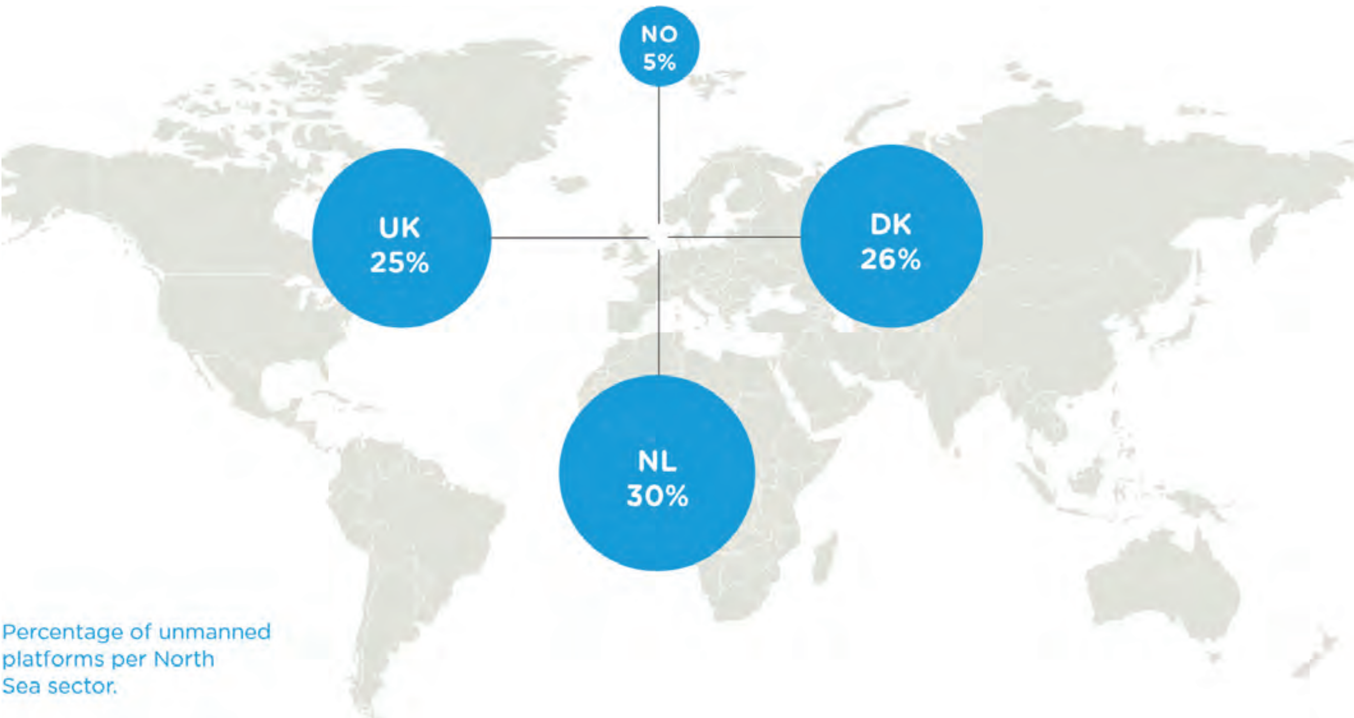
The attraction in those areas is water depth and availability of other facilities to tie into. Unmanned facilities are at home in 35-150m depth, Ramboll says, and have helped to tap smaller fields where lower capex has been key. There are 200 in the Middle East, and around 1000, or 25%, in the US Gulf of Mexico, according to Ramboll's report for the NPD.

Norway has five normally unmanned facilities, in 70-125m water depth: Tambar and Hod (operated by BP), Embla (ConocoPhillips), Sleipner B (Statoil) and Huldra (Statoil), which was shut-in in 2014, according to Statoil.

Henrik Juhl

While in other areas, shallow water, small reservoirs and proximity to infrastructure have helped drive use of normally unmanned facilities, the norm in Norway has been for bigger fields, driving up the scale of its facilities, says Henrik Juhl, Ramboll's senior director, offshore pipelines, subsea and jackets. "Going small hasn't been part of the mindset," he says. There also hasn't been the same proximity to infrastructure and shallow water depths as in other areas, and regulatory requirements have been limiting, says the Ramboll report.

Yet, there appears to be potential. According to the NPD there are approximately 90 discoveries on the



Unmanned distribution. Image from Ramboll.

Norwegian Continental Shelf (NCS) under consideration for development. The lion's share is marginal in volume, and many of them are candidates as tiebacks to nearby host platforms. But, many are located less than 50km from existing infrastructure, and many even less than 20km, a range which an unmanned wellhead platform could become a very efficient solution, Juhl says.

There are various options for minimal facilities, Juhl says, with the smallest being a monopile, or a "wellhead on a stick," as it's been called. It has been used in the Gulf of Mexico, Middle East, Denmark [Tyra South East A and Cecilie] and the Netherlands. These often just operate one well.

Mono column designs

Indeed, mono-column platforms (MCPs) are a viable option for the Norwegian market, according to Bergen Group and Singapore-based Calm Oceans, which agreed to an agency deal to market the concept earlier this year. Their concept is a self-elevating, multipurpose jackup with up to 5000-tonne deck load, for up to 130m water depth.

The platform essentially comprises a deck box, four-chord square truss structure (mono-column) and a mat foundation. With the mat design, the MCP can operate in oil fields with soft seabed, seen as challenging for conventional jackups.

The MCP design, which comes from Brian Chang, who owns Calm Oceans

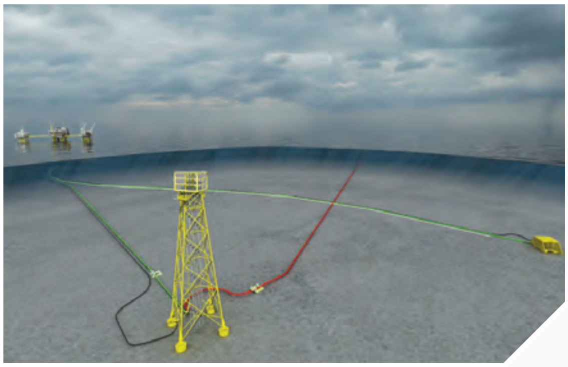
Vestflanken 2

Statoil and partners Petoro, Total and ConocoPhillips have estimated the development cost for Vestflanken 2 as NOK 8.2 billion (US$960 million). This investment will enable the production of around 110 MMboe.

The wellhead facility will have 10 well slots. To increase the recovery of oil, two of the slots will be used to inject gas. In addition, two production wells will be drilled from an existing subsea template on the Vestflanken.

Further injection will take place by bringing in gas through a new pipeline from the gas injection system which already exists in this area. The wells on Vestflanken 2 will be controlled from the Oseberg field center, where the oil and gas will also be processed.

The wells at Oseberg Vestflanken 2 will be drilled by the new category J jackup drilling rig Askepott, which is currently under construction. It is owned by the Oseberg license.



Vestflanken 2, artists' impression. Image from Statoil.

Contractors selected for work bringing on Vestflanken 2 include Technip (pipelaying), Ocean Installer (marine construction), Heerema Fabrication Group (EPC of the unmanned wellhead facility), and Heerema Marine Contractors (transport and installation). In addition, Aibel will work on the Oseberg field center to receive the well stream from Vestflanken 2, and FMC Technologies will supply two subsea trees. ▪

and 33.1% in Bergen Group, has been classed by ABS, adhering to mobile offshore unit code 2008 and other relevant IMO guidelines.

The advent of access solutions such as walk-to-work systems could be seen to be an enabler for this technology, because it means helicopter decks are not required, which come with all manner of support systems, from lighting to deluge systems and power systems to support those, increasing facility size, Juhl says. Indeed, Statoil is planning to use gangway access systems off support vessels for when staff are needed on the Vestflanken 2 facility.

Just how welcome using motion compensated gangways will be offshore Norway is yet to be seen. Such technology has been used in the North Sea for a number of years, both in response to helicopter groundings in 2013-14, giving an alternative means to get staff to work in the UK sector, and also as a regular access option for offshore wind farms from smaller vessels. To economically make use of such a system, ideally you would need 2-3 normally unmanned or minimal facilities operating that could be served by one vessel.

Regulations

There are also regulations with which to contend. "In Norway there are challenges in terms of regulations and meeting all the guidelines in place," Juhl says. "In other areas regulations are driven more by a safety case [which enables more freedom in the design]." In Norway, regulations and guidelines were drawn up for an industry that had been focused on very large facilities, so it is felt they don't address unmanned facilities.

Ramboll's report says that regulations do support the concept of unmanned wellhead platforms. But, it says the industry's "underlying guidelines and NORSOK standards have more focus on mitigation measures requiring more systems, equipment and maintenance, and therefore do not support the concept of unmanned wellhead platforms, and most unmanned wellhead platform concepts will be non-compliant with the guidelines and the NORSOK standards. But in principle, the underlying guidelines and NORSOK standards are only one way of fulfilling regulations. Alternative solutions may be chosen, provided that the operator can demonstrate that these are safe and fulfil the detailed requirements in the regulations."

However, the report suggests a new guideline and/or a NORSOK standard should be developed that provides an approach for the design of unmanned platforms on the NCS.

There is interest in this concept, not just from Statoil. So far, Ramboll has done 5-10 studies for minimal facilities in Norway, including Statoil's Vestflanken 2, but also for projects for ConocoPhillips and Total.

For Total, Ramboll made a study for an alternative for the Tor field, where the facilities were shut in on 1 January this year, having reached the end of their life. Yet, it is thought that there are still reserves that could be extracted if an economic option could be found. Ramboll also did studies for unmanned and not normally manned satellites for the Johan Sverdrup field. OE

Marginal in Malaysia

Malaysia's MISC has built a minimal facilities FPSO for use on marginal fields. John Sheehan takes a look.

Tapping the potential of marginal oil and gas fields offshore Malaysia will be a key to the country's aims to grow oil and gas production by 5%/yr up to 2020.

Malaysia, which has 409 oil and gas fields and the second largest reserves in Southeast Asia, currently produces about 730,000 b/d of crude oil and 2 Bcf/d of natural gas, making it the world's third largest exporter of LNG.

Production growth is expected to come from enhancing output from existing fields as well as from new marginal fields coming onstream. These marginal fields are expected to contribute an additional 55,000 b/d in output by 2020.

Shipping company MISC Berhad, which is continuing to expand into the offshore arena, has developed a solution for tapping these smaller fields with a marginal mobile production unit (MaMPU), which complies with marine standards for offshore oil and gas production.

Syed Hashim Syed Abdullah, vice president of offshore business, MISC, told OTC Asia earlier this year: "We looked at how we could address the economic requirements of marginal fields. There is a huge capex involved in developing fields with FPSOs, FSOs and FSUs, so MISC came up with the MaMPU concept to provide a technical solution to monetize stranded fields."

He said the marginal fields off Malaysia could remain undeveloped because of the huge cost of putting in infrastructure.

To cut these costs, MISC has converted an oil tanker into the *MaMPU1* production unit, which offers 318,000 bbl of storage capacity, 15,000 b/d of oil processing capacity, and gas handling capacity of 25 MMcf/d.

The spread-moored vessel is designed to produce from fields with proven reserves of between 3-10 MMbbl. It is aimed at tapping a cluster of 4-6 oil fields to be developed over a 10-15 year time span.

The tanker was converted at the Malaysia Marine and Heavy Engineering yard in Johor in just eight months. It contains a central control room and an accommodation block for up to 45 people.

An NGLTech Sep i-SYS crude oil separation unit has been installed on the topsides to separate the produced oil, gas and water. The compact system is relatively lightweight and has minimal controls. It is capable of handling a large slug volume as well as sand without causing flow fluctuations.

MISC is understood to be offering the *MaMPU1* for use on the Ophir field development project off Malaysia. Development plans for the field involve a single wellhead platform, from which three producers will be drilled, and a leased FPSO.

The MaMPU concept is similar to one being touted for marginal fields in the North Sea by Amplus Energy Services for its versatile production unit (VPU).

The Amplus VPU *(OE: May 2016)* uses proven FPSO and DP vessel technology and is based on the concept of the *Seillean* (gaelic for honeybee) FPSO. The Seillean was originally developed by BP in the mid-late 1980s to perform production, storage and transportation operations on the various marginal field developments BP had in its North Sea portfolio at that time. It was designed to suck up oil from small fields and quickly move on.

Amplus Managing Director Ian Herd said that the VPU is based on a standardized approach, with the concept being dubbed "project Mondeo" after the ubiquitous Ford car.

"We already have invested more than US$5 million in the development of our VPU, and it has been specifically designed for small/medium-sized fields or as an early production system on larger fields," Herd said. OE

Malaysia Marine and Heavy Engineering handle the conversion (fabrication, installation and integration) of the FSO *MaMPU 1.*
Photo from Malaysia Marine and Heavy Engineering

Changing the game

In advance of OE's 2016 Deepwater Intervention Forum, held in Galveston, Texas, Audrey Leon discusses the next game-changing technologies with the forum's board members.

The Helix *Well Enhancer.*
Photo from Helix Energy Solutions Group.

What are some of the intervention technologies you are currently following – are there any potential game changers?

Jason Leath, Lomac Oil & Gas: I am most excited about the success Wild Well Control has recently had with their annulus isolation tool (*OE: July 2016*). In the past, less effective methods may have been utilized in attempt to correct difficult annulus issues. But, now because of this proven game-changing tool, operators may have the backside access that's been needed.

Alex Lawler, LLOG Exploration: Riserless deployment of coiled tubing should be available within a year. This capability will be a step change for riserless interventions. To date, only slick and electric line options have been available. The ability to use coiled tubing in a riserless application offers an array of downhole options not previously available to the industry. On another front, there are intriguing developments with regards to casing cut and pull operations. Rigless options and open-water pressure control applications are being developed and tested.

OE's Deepwater Intervention Forum will be held this August 9-11, 2016, at the Galveston Island Convention Center. For more information, please visit: www.deepwaterintervention.com.

David Carr, Helix WellOps: Helix is always looking at ways in which technology can be employed to improve the cost-effectiveness of well intervention, as well as reduce the cost of decommissioning. Our first 15,000 psi intervention riser system, which is being developed with OneSubsea – a fellow member in the Subsea Services Alliance – will allow for the efficient intervention on high-pressure wells in deepwater without the need for a 15K subsea BOP (blowout preventer) and rig, which remain high cost assets, even in the current environment. It will also be available as a rental item.

Helix also recently completed the first coiled tubing intervention from an LWI (light well intervention) vessel in the North Sea with a WIU2 notation. This operation opens up the potential for major cost savings for North Sea intervention. Innovative engineering was required to prevent coil fatigue and compensate the CT lifting frame.

On the decommissioning side, we are developing a large bore environmental containment system that we expect will allow us to expand our open-water tubing pulling activities in the Gulf of Mexico, as well as potentially bring this methodology to other basins, such as the North Sea and Brazil. This technology further extends the capability of Category A and B intervention vessels, and should reduce the risk of abandonment by allowing for better definition of the rig spread that will ultimately perform the upper abandonment.

What are some of the positives occurring in the industry at the moment?

Jason Leath: Competitors are not only talking to each other; they are even teaming up. It also looks like service providers may be recognizing operators as partners or investors rather than just bags of money. In turn, operators may be seeing the service provider as a specialty tool to be polished and maintained.

Alex Lawler: The emerging technologies of yesterday have become the proven technologies of today. The amount of successful operations continues to build, demonstrating not only the technical viability of the intervention industry, but the safety and cost efficiency. More and more operators are becoming comfortable with rig-alternative options to execute their intervention and P&A (plugging and abandonment) backlog. It's undeniable that the intervention sect of the industry has a bright and expanding future.

David Carr: The current downturn is requiring operators to look at very different commercial models for their well intervention and abandonment requirements. This involves moving away from the traditional 'day rate' model to a more collaborative and mission-aligned approach. This is a positive development for service companies that have the experience, the technology and a strong financial structure to tackle it. **OE**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Enhancing production

Back deck of an Oceaneering vessel. Images from Oceaneering International.

Oceaneering's Justin Pizzitola discusses the use of an open water dual coiled riser based system for rigless stimulation.

For more than two decades, the complexity of the deepwater environment has become more challenging, driving the need for more alternative solutions and advancements in technology. From new wells that come online to aging wells, well intervention is required to stimulate flow and maximize production. An alternative, rigless stimulation method has been developed and used successfully on dozens of wells in the Gulf of Mexico and West Africa. Production enhancement from this alternative method yields results comparable to those achieved using rig-based methods while reducing costs by as much as 50%.

Aging wells need rejuvenation

After a subsea well is online for several years, its production can be impaired by sand migration and/or by deposition of wax, paraffin, asphaltenes and scale. Increased water cut in older wells can contribute to deposits. The first step to restoring production is for oil company production engineers to analyze the produced fluids to determine the cause of the blockage and to select the appropriate treatment chemicals. During this analysis, the engineers also review reservoir characteristics to determine the formation's injectivity and optimum pumping rates.

High-cost rig-based intervention

Until 2009, the only method of performing subsea stimulations was to deploy a mobile drilling rig and a high pressure pumping vessel. In the current environment of low oil and gas prices, floating rigs may be readily available, but increased drilling activity will likely make scheduling of rigs much more problematic. Even at today's depressed day rates, contracting a rig can still be an expensive proposition. Once on location, preparations for the stimulation job – including setting a blowout preventer and drilling riser to connect the subsea wellhead to the surface – can take a week or longer. Large crews for the rig, pumping vessel, and asset support teams, add to the cost. Operators can spend as much as US$20 million on a rig-based subsea well stimulation.

Rigless intervention

An alternative method, developed by Oceaneering International, uses a multiple-purpose service vessel (MSV) to safely and efficiently perform well stimulations without a drilling rig or riser. The MSV carries two work-class ROVs, and has a crane for lowering equipment with varying tonnage to the sea floor. Equipment includes one or two open water dual coiled tubing riser units, flying leads, high pressure pumps and associated high pressure piping, and an innovative well stimulation tool. The MSV can carry up to 5000 bbl of treatment chemicals. If a higher chemical volume is required, a second pumping vessel can be employed to avoid additional trips to shore. This method allows for rig-up and testing to be completed in as little as two days so stimulation can begin quickly.

The well stimulation tool is the main interface between the topside and the well tree. To assure safe operation, it provides a double barrier for well control, and includes two "fail-close" valves, that are API 17G compliant, which can be actuated from the surface, or automatically close if unexpected pressures are encountered. The system can be configured to perform 10K psi or 15K psi stimulations as required.

The system has an emergency quick disconnect system (EQD) that enables the vessel to disengage from the well with zero leakage. The EQD can be released using an ROV, via an electric control line, or with a deadman cable that activates the EQD in case of loss of station keeping or a black ship situation.

Advantages of rigless systems

Unlike rig-based interventions that must access the wellhead vertically, there are several options for connecting the well stimulation tool to the subsea wellhead. It can be deployed and landed using a mud mat, or secured to a suction pile installed in advance of the stimulation then attached to the wellhead with a flying lead. On vertical trees, the well stimulation tool uses an H4 connector directly to the tree. On horizontal trees, the H4 connector is connected by a flying lead to a choke interface. Another advantage of Oceaneering's rigless method over rig-based interventions is its ability to perform the stimulation on horizontal trees without removing the crown plug in the tree. Plug removal is needed for the drill pipe used for rig stimulations to engage vertically with the wellbore. Using this method, a variety of interfaces are available including choke inserts and high flow manifolds, which do not require plug removal.

Rigless intervention capabilities

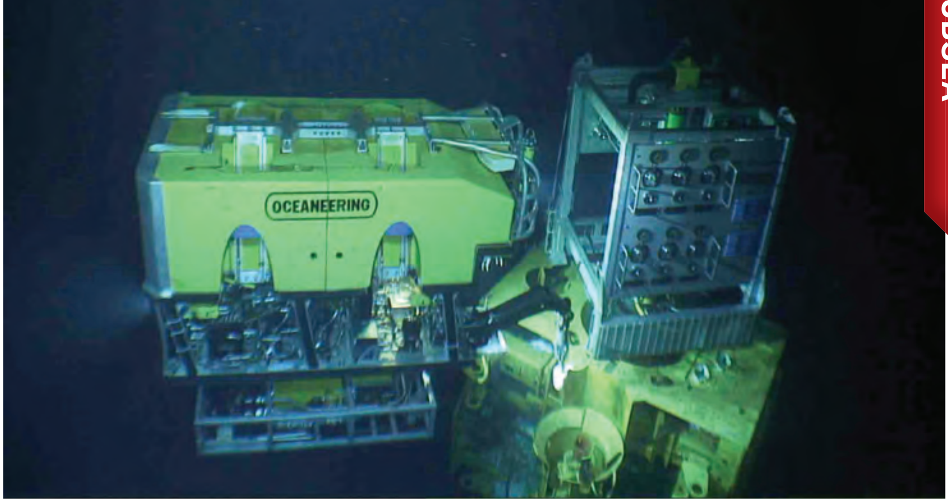
Currently, the rigless stimulation method can treat wells at high pumping rates up to 15K psi with open water dual coiled tubing riser units. With this process, the subsea tree can be controlled from the vessel through an umbilical distribution system that provides power and communications to the tree locally, without relying on control from the distant host facility, and can close safety valves as required. During operation, real-time topside and subsea data is streamed back to shore, including pump pressure data, ROV video, pressure transducer and flow meter readings.

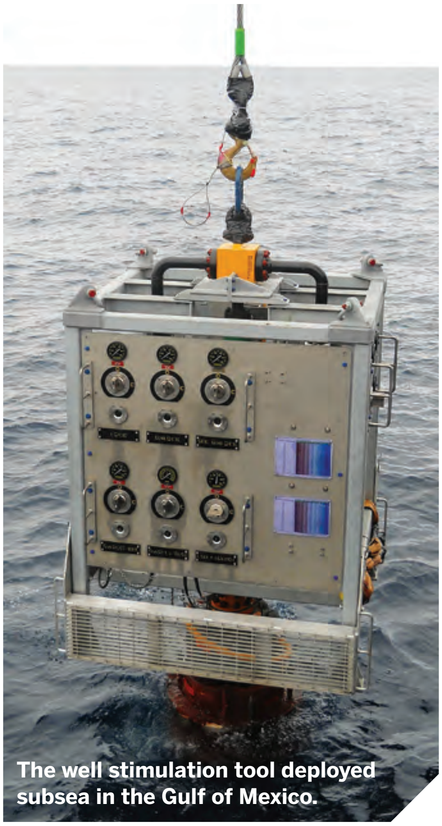
Project management yields results

Project management is an important aspect of successful subsea well stimulation. Oceaneering's production enhancement team provides project management, engineering, and offshore service technicians specifically trained to integrate all in-house and third-party services. This provides for the consistent execution of well stimulation activities, strong customer support, and reduces offshore downtime.

Since 2009, more than 30 rigless well stimulations have been completed successfully in waters as deep as 6700ft in single and dual-vessel applications, resulting in average production increases of 50% and savings of as much as 50% compared to rig-based stimulations.

The Oceaneering Millennium ROV is connecting the flying leads from the well stimulation tool to the subsea tree.





The well stimulation tool deployed subsea in the Gulf of Mexico.

Case studies

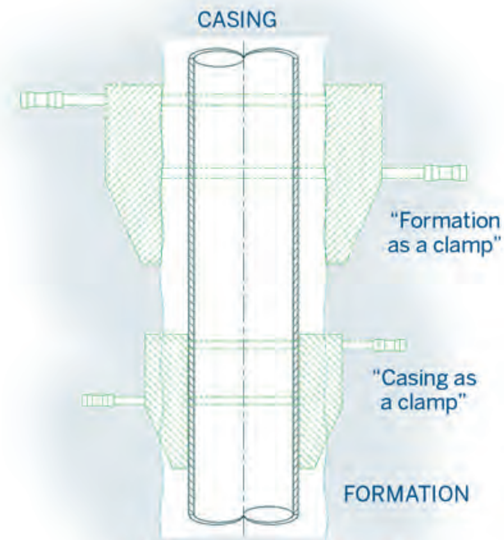
A subsea well in the Gulf of Mexico experienced a significant drop in production due to formation impairment. A rigless stimulation was performed from an MSV, using a wellhead stimulation tool to bullhead 1100 bbl of acid at 11K psi at the tree. Despite bad weather, the stimulation was completed in 18 days (including three days of pumping), for $15 million less than a rig-based operation, and improved the well's productivity by 75%.

Also in the Gulf of Mexico, production from two wells in 4300ft of water was impaired by fines migration. The operator determined that each well needed a treatment schedule pumped within 15 hours at volumes exceeding a single vessel's capacity using premixed chemicals. A rigless stimulation was carried out using an MSV and a second, low-pressure pumping vessel. Bulk treatment chemicals were mixed on the fly during stimulation. The operation was completed successfully and produced higher production numbers than originally anticipated.

Offshore Ghana, an operator determined that production from five subsea wells had dropped significantly because of accumulation of fines, calcium carbonate and scale. A dual-vessel, rigless stimulation was performed, combining the capabilities of an MSV and a construction vessel. Four open water dual coiled tubing riser units were used to pump the treatment chemicals at 16 bpm to a specially modified well stimulation tool. Each of the wells in the five-well campaign saw an average production rate increase of more than 70%. OE

Raising resin's profile

Endeavor Management's Keith Caulfield and Mike Cowan examine the results of a recent JIP that showed resin may be a potential alternative to cement in P&A operations.



"Clamp" analogy

Each layer of a well acts as a clamp, restraining the contents inside.

Endeavor Management recently completed a joint industry project (JIP) covering covering several subjects related to the decommissioning industry. One that was of intense interest to JIP member companies was the use of resins for well plugging and abandonment (P&A).

Endeavor Management has researched the potential for resin as an alternative to cement. We set out some of the conclusions here.

For years, resins have been viewed as a dramatic upgrade to cements for many uses in well construction, remediation, and P&A. However, three factors have contributed to keep resins from being more widely used: the "durability gap," dealing with uncertainty of the long-term durability of resins, the "knowledge gap," created by the lack of resin-trained industry personnel, and the perception that resins are much more expensive than cement.

Sealing comparison

Any P&A barrier must create a "sealing boundary" between the different regions of a well:

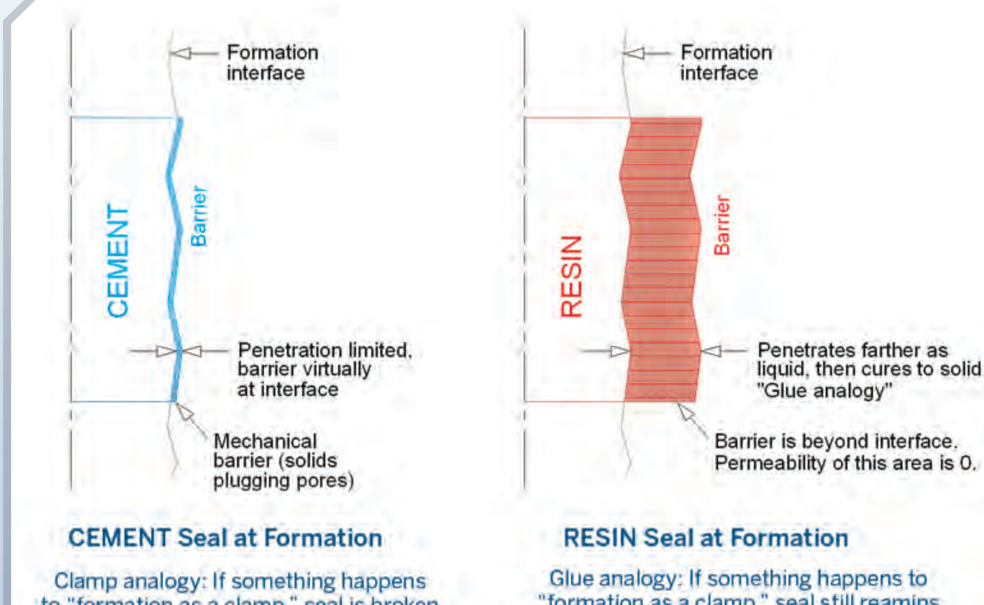
- Sealant/formation
- Sealant/outer casing surface
- Sealant/inner casing surface

Cements are placed as a liquid full of solids-in-suspension. As cements hydrate, they cure into a rock-like solid. Any seal created is predominantly mechanical.

At the interface between cement and formation, the solids-laden cement does not penetrate very far into the pores, leaving a seal that exists virtually at the formation wall. This interface can follow variations in the mating surface. There can be a chemical bond component to formation and casing, but the overall sealing bond is mainly a mechanical bond defined by friction and a solid-to-solid interface.

A broad analogy describing the way cements seal is "the clamp." A clamp applies mechanical load (compression) to the items being secured. Mechanical seals in a clamped joint need the force provided by the clamp to create the seal. As long as the clamp remains, the system is stable. Move, jiggle, or relax the clamp and the properties of the entire system are changed for the worse.

For resins, the sealing mechanism is completely different. At the formation interface, resins – being liquid during placement – penetrate far deeper into the formation than cements. With



CEMENT vs. RESINS: Seal at Formation

resins, the sealing interface is actually out in the formation instead of being at the interface. At the interface between well and formation, resins seal by spanning this interface, rather than sealing at the interface.

There is a chemical bond between resins and the casing. A well-formulated resin can achieve characteristics similar to a heavy-duty radial tire, with no matrix permeability and good adhesion to the various well surfaces. Cements cannot do this.

Simply put, resins have material properties more tolerant of the differential stresses that can cause barrier failure.

An analogy that best describes the way resins seal is "the glue." A glued joint, especially with glue forgiving of relative movement, only needs clamping action (external force) until the glue cures. After that, the clamp can be moved, jiggled, or relaxed at will; the glued joint will remain intact. After curing, the glue seals by chemical bond.

With the right type of glue, a glued joint will last far longer than a clamped joint. In similar fashion, a well-chosen and well-placed resin barrier can last far longer than a cement version. So, if you move, jiggle, or relax the clamp on a glued joint, the 'glue' (resin) will still seal while a clamp-dependent mechanical seal (cement) will not.

While the "clamp" (structure) of any oil well is typically very robust, what might happen to these "clamps" over geologic time frames? When you replace the cements with correctly-engineered resins, the barriers no longer remain dependent on the "clamp" for effectiveness; they can seal even if things happen to the formation interface.

Durability gap

As shown above, there are many ways that resins can effect a "step change" improvement in reliable well barriers. There is general agreement among cementing experts that resins will seal problematic well interfaces differently and more effectively – If these better seals can be trusted for the time frames necessary in permanent well P&A.

There is no better time to move forward and remove that big "IF" from this situation. It becomes obvious that a subject ripe for industry collaboration is to determine the "price tag" for a thorough study of the long-term durability of resins as effective sealing barriers in oil well utilization.

Knowledge and cost gaps

Factors that have combined to keep resins from being more widely used include:

1. Cements are far more established in the industry, having been used since its beginnings.

2. Knowledge of where and how to use cements is very common.

3. Resins have varied formulations that can be custom-fitted to nearly any well situation. However, practical knowledge is limited to few people or organizations.

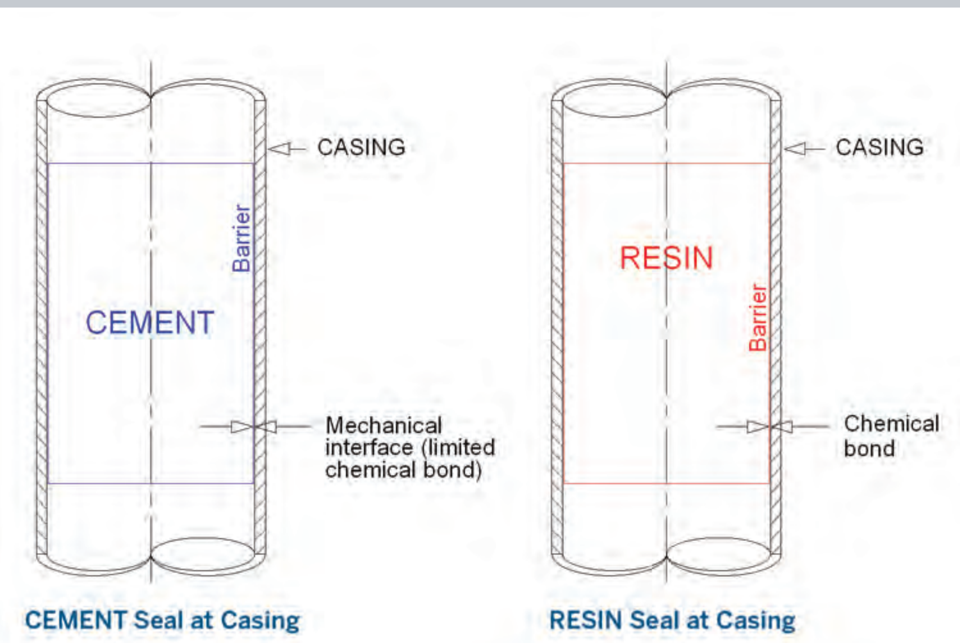
The use of cements as a major component of well construction has generally been successful, when viewed from a historical perspective. Stated perhaps too simply, these demands have been to get the resources out of the ground economically and without hurting anybody. In the last 50 years, they were augmented to include "and do no immediate harm to the environment."

The decommissioning industry must consider time frames far beyond the scope of any past oilfield activity: the demands of geologic time, taking into account not only the present, but extending thousands of years forward. This new perspective forces us to look for a better sealing material.

Knowledge gap

Small numbers of people know enough about resins to enable change to occur across the breadth of the industry. If resins are to improve the quality of well P&A sealing, then much effort needs to be put into wider education around how to best use them.

The industry could collaboratively help establish an educational program that will spread the specialized knowledge of resins to benefit the industry. A field guide for resins will be needed for the future, just as cementing guides exist today.



CEMENT vs. RESINS: Seal at Casing

Cost

The cost per unit of resins can be 25-40 times the cost of cement. However, resins' high material costs can be overcome with field operations that fully exploit their technical advantages.

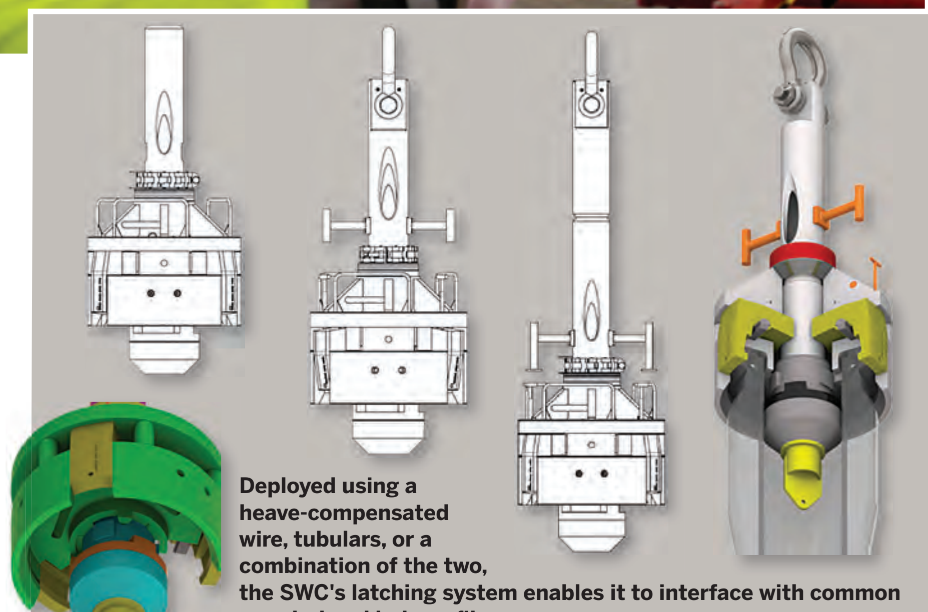
Conclusion

There are three gaps that must be bridged for the use of resins to become common, even though they provide an improved sealing mechanism quite different than cements. If two of these gaps – industry knowledge and proof of their durability – are closed, the third – resins' higher material costs – can be demonstrated to be less that cement on an installed basis using field techniques that offset these costs and enable a true step-change improvement in well sealing. OE

Clients observe a multi-operator factory acceptance test of the SWC at a Weatherford research and development facility in Aberdeen, Scotland. Photo courtesy of Weatherford International.

Building a connection

Jerry Lee takes a look at Weatherford's new subsea wellhead connector, which allows operators to use vessels of opportunity for P&A work, reducing the cost of decommissioning operations.



Deployed using a heave-compensated wire, tubulars, or a combination of the two, the SWC's latching system enables it to interface with common mandrel and hub profiles. Images courtesy of Weatherford International.

Abandonment and decommissioning is set to rise as older oil and gas developments become costlier to maintain and operate during the current downturn. Research and Markets forecasts a 20.4% CAGR out to 2020 for the global offshore decommissioning market. In the North Sea alone, Douglas Westwood projects that US$48 billion will be spent on plugging and abandonment (P&A) work (*OE:* June 2016).

Several companies are working to bring down decommissioning expenses. Weatherford has created a subsea wellhead connector (SWC) with this goal in mind. The SWC can be deployed from a vessel of opportunity (VOO) – a mobile offshore drilling unit (MODU) or monohull vessel – for P&A or re-entry operations.

Abandoning a subsea well is completed in three phases: primary reservoir isolation, intermediate reservoir isolation, and environmental isolation with wellhead recovery. Typically, a MODU is contracted for the entire operation, however, Weatherford's new SWC seeks to change this by performing phase three with a less expensive monohull vessel, allowing the operator to save 40-60%, conservatively, on this phase, says Steven Canny, engineering lead, Well Abandonment and Intervention Services, Weatherford.

The SWC is a mechanical connector that can latch onto a subsea wellhead (via rotation) and allows electro hydraulic continuity to the bottomhole assembly for P&A or intervention work. The design is based on Weatherford's MOST (mechanical outside-latch single-trip) subsea wellhead retrieval tool, using its latching mechanism.

Using the MOST tool as a base, engineers redeveloped the connector to be run with tubulars, including intervention riser, or on a heave-compensated wire and a work-class ROV (remotely

SUBSEA

operated vehicle) – enabling the cost effective rigless deployment. ROV guide arms were added to the lifting sub and a breakthrough was added to allow umbilicals or electrical flying leads to access apertures in the lower interface of the connector allowing electro hydraulic continuity to the severance tool or well. ROV stabilization bars, position markings, and a secondary failsafe mechanism were also added to the connector.

The SWC can be used on all common 18.75in bore wellheads, with mechanical, abrasive, or explosive severance tools for P&A campaigns, and a small re-entry mandrel seal assembly for interventions. Deployment can be vertical or horizontal, and operations would only be limited by the ROV's limitations.

From when the project was sanctioned to the factory acceptance test (FAT), the development process came about quickly.

"It took 28 days to go from a kickoff meeting, sitting in an office, to delivery at a client-witnessed FAT," Canny says.

Since then, four P&A campaigns on the UK Continental Shelf (UKCS) in the North Sea have ran the SWC.

"The first campaign was a multi-operator campaign for one well using a monohull anchor handling vessel (AHV)," Canny says. "This proved to be the most challenging deployment; however, it displayed the value of the SWC, without which the campaign could not have been performed."

Performed in September 2015, the SWC was horizontally deployed through a small moonpool on an AHV with minimal on-deck equipment in 286ft water depth. The objective was to recover a 10M hub profile wellhead for a multi-operator intervention and P&A campaign. To achieve this, the operation required an abrasive cutting tool, supplied by one of the SWC project's partners, to cut through 30in, 13.375in and 9.625in casing. During operations, the ROV was able to hold onto the SWC; however, as it began thrust for rotation, the manipulator arms on occasion slipped down the bar. This led to modifications of the API ROV interfaces to allow the ROV to handle the tool better. On the lifting sub, the ROV guide arms were lengthened and a positive stop was put on the end to give the ROV more area to grab and prevent it from slipping during rotation. On the connector, the diameter of the stabilization bars was increased from the API recommended 0.75in to 2in so the ROV could hold the tool more securely. This campaign also led the tool to be redesigned with a 4.5in box connection, so it could accommodate drill pipe and a pad eye crossover to give the operator more flexibility on a campaign.

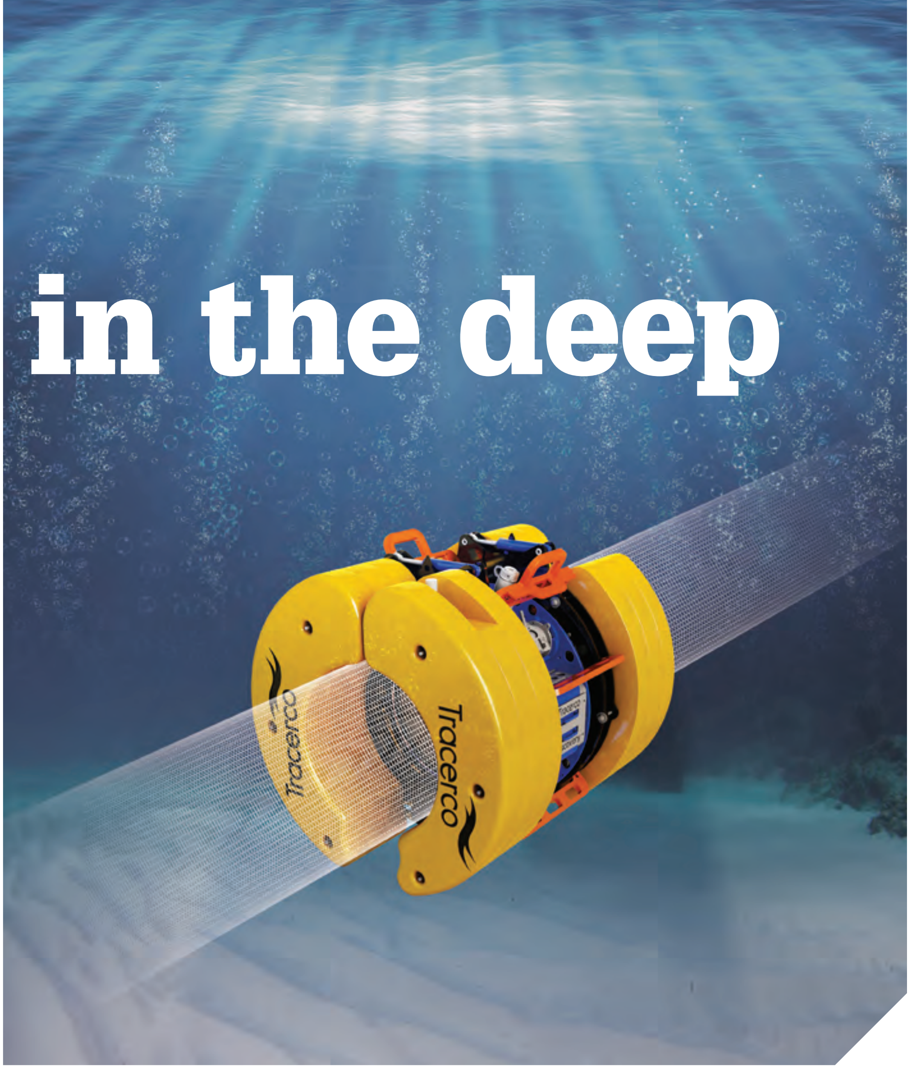
Once the cuts were complete, the tool and wellhead were recovered over the side of the vessel. The operator's savings were significant on this campaign due to the exceptionally low day rate and AHV availability compared to an intervention vessel or MODU, Canny says.

The SWC was then deployed on three more UKCS North Sea campaigns.

"The second and third campaigns were for tier-two operators from monohull intervention vessels with deployment through an intervention tower," Canny says. "The fourth campaign involved nine wells using a MODU and was run on drill pipe, which enabled the operator to run abrasive technology from a MODU for the first time globally – demonstrating the flexibility and capability of the SWC, and the value it delivers". OE

Seeing in the deep

Assessing the condition of pipelines, especially as they get older, is an increasing task. John Sheehan surveys potential solutions.



Tracerco's Discovery tool. Image from Tracerco.

The expansion of the offshore industry in recent decades has brought with it a huge growth in subsea pipeline infrastructure.

From the Åsgard Transport pipeline in the Norwegian North Sea to the West Natuna gas pipe line in the South China Sea, thousands of kilometers of offshore pipelines have been laid, all of which need regular inspection, repair and maintenance.

The focus on asset integrity management has also sharpened as operators look to increase the lifespan of mature assets.

Key to this are advances in both internal and external pipeline inspection technologies, which operators use to check for corrosion degradation and pipeline blockages.

Companies such as GE PII Pipeline Solutions, Rosen, TD Williamson and NDT Global among others are in the frontline in the battle against pipeline defects.

Halfwave

Smaller companies are also playing their part and Norway's Halfwave has developed Artemis, a potential solution for operations in areas where the combination of deepwater and thick protective coatings rules out most traditional methods for non-intrusive pipeline inspection.

Based on acoustic resonance technology (ART) developed by DNV (now DNV GL) over the last 20 years, Artemis has been honed for inspection of rigid and flexible subsea pipelines.

The system is designed to check pipelines at depths up to 10,000ft, providing high resolution information by inspecting through coating materials and avoiding costly subsea mechanical intervention. The system clamps onto the pipe and provides real-time data to the topside inspection team. It is deployed by remotely operated vehicle (ROV) and performs a 360° scan using ART. The technology works with a sending transducer transmitting a broadband acoustic signal towards the pipeline. The signal spreads in the metal pipeline and a response is detected by a receiving transmitter, with the results then analyzed revealing resonance peak frequencies from which the structure's thickness can be estimated.

The system can be launched from offshore installations using an inspection class ROV or from a vessel using a work class ROV.

Discovery

Another company providing clamp-on technology for pipeline inspection is Tracerco with its Discovery and Explorer offerings.

Discovery can perform a detailed high resolution CT scan of subsea pipelines, distinguishing between wax, hydrate, asphaltene or scale deposits, data that is paramount when planning any flow remediation campaigns. It can also detect wall thinning, corrosion and pitting.

Discovery is deployed using an ROV and clamped onto the pipe, with real-time communications allowing instant assessment of pipeline conditions.

Explorer meanwhile, can fast screen pipelines (100m/hr) to locate restrictions. Explorer detects the location of deposit build-ups by measuring the density profile of the pipeline and then analyzing any detected anomalies. An abnormal density, in relation to the material flowing in the line, indicates a build-up of deposit.

Both devices work without the need to remove the pipe coating material. Once Explorer has located the area of the suspected blockage, Discovery can be deployed to accurately characterize its precise nature.

The technology has recently been deployed to Australia, where there are more than 4000km of subsea pipelines in operation.

"Operators who face flow challenges need to get their pipelines back

to full operation quickly," says Ken Pearson, Tracerco's managing director in Australasia. "The speed at which we can deploy, coupled with the fact that coatings do not need to be removed from the lines before inspection, saves time and costs whilst mitigating the risk of damage to the pipeline."

Pigs get smarter

For internal inspection of pipelines, inline inspection tools, or smart pigging devices, are being used to help fight corrosion, cracking and blockages. The global inline inspection market is estimated to be worth about US$1 billion a year.

"A smart pig is a highly advanced piece of technology that we run inside a pipeline to inspect it," explains Andrew Greig, operations engineer with pipeline operator Kinder Morgan. "Smart pigs have numerous sensors on them and inside them they have a computer and a hard drive that gathers data and stores it.

"Smart pigs use all sorts of highly advanced technologies, some similar to those used in a hospital like ultrasonics. Once we run the pig through the line we get a massive amount of data and we go through it and make sure we find all the critical areas and address them accordingly."

Several runs are usually made in the pipeline, with a cleaning pig with brushes, magnets and scraper tools employed first to remove any debris from the pipe.

A geometry tool with caliper arms is used to check for any geometric faults such as dents that might be affecting the pipeline. The smart pig is then run to detect for any general thinning or corrosion in the pipeline.

The intelligent pigs are equipped with highly tuned sensors that can gauge the thickness of the pipes they are traveling through along with cracks, fissures, erosion and other problems that may affect the integrity of the pipeline.

The pigs, which are launched and recovered in the pipeline, collect data and transmit it to a team that interprets that data to gauge the health of the pipeline segments being scanned.

If any problems are found then teams not only know what the problem is thanks to a heavy set of data points, but know exactly where to go to replace the affected pipe thanks to highly tuned sensors.

Balltec goes flangeless

As the technology of the pigs themselves evolves, so too does the technology to launch and recover them. Balltec recently launched its flangeless pig launcher, which can be used in pipeline repair jobs.

"What Balltec has developed is a pig launcher that can be used in emergency situations or in adverse conditions where a section of pipe needs to be cut and that section of pipe then needs to be plugged," Martyn Conroy, Balltec's VP of sales and marketing, told *OE*. "The pig launcher fits over the end of the open pipe and we have a pig that is held in a canister in the back of the tool and gripping mechanism that can grip hold of the pipe. Simple adjustments can be made to the gripping section to ensure that we can not only grip onto steel pipe, but we can accommodate any coatings that are on that pipe."

Conroy said that the technology was developed when a client approached Balltec because they had an issue where a piece of pipe had been damaged during laying and they needed to cut out a section. In order to cut out the section they had to de-water that section as well.

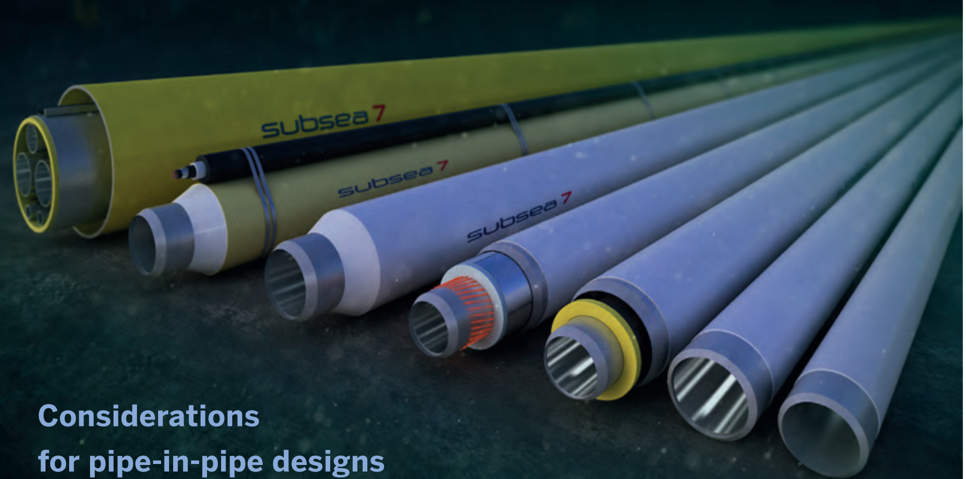
"The end user was Total in the North Sea," Conroy says. "Leading on from the back of that we were actually picked up by Statoil, which was doing some inspection, repair and maintenance work on the Åsgard Millom pipeline. They wanted to be able to use the pig launcher to inject a TD Williamson smart plug into the pipeline to plug a live pipeline."

The existing technology was significantly re-designed to accommodate a larger smart plug of 4.5m in length with a mass of 1500kg. The plug launcher gripping mechanism was built to withstand pressure of up to 120 bar from within the pipeline.

"This is a unique piece of subsea equipment," says Jon Jackson, Balltec engineering manager. "The subsea plug launcher is flangeless and allows the insertion of plugs without any existing infrastructure by gripping and sealing the end of a cut pipe. The plug can be launched via a simple hydraulic system and operated with minimum remotely operated vehicle intervention. This allowed our client to have no production loss during tie-in."

The whole project was delivered to Technip and was successfully deployed and used in the Åsgard field in August 2015. **OE**

Pipe-in-pipe solutions



Subsea 7's flowline solutions (from left: bundle, direct electrical heating pipe, wet insulated pipe, electrically heat traced flowline, pipe-in-pipe, lined pipe and single pipe). Image from Subsea 7.

Considerations for pipe-in-pipe designs for high-pressure, high-temperature fields were set out by Subsea 7 engineers at this year's OTC. Jerry Lee takes a look.

When producing from high-pressure, high-temperature (HPHT) fields, oil and gas production retains much of the heat it had in the reservoir. But, when it gets to the pipeline, this heat tends to dissipate to the environment, as it is exposed to low seafloor temperatures. Here the possibility of hydrate, wax, and asphaltene formation, resulting in pipeline blockages, increases, particularly during periods of prolonged shutdowns. One option to limit the cooling effect is to use pipe-in-pipe (PIP) systems.

In order for a single pipe system to be used in a deepwater field, the pipe would need to be covered with thick, multi-layered insulation. However, this would result in a low pipeline specific gravity and cause stability issues, according to a paper presented by authors from Subsea 7 at this year's Offshore Technology Conference (OTC) in Houston. PIP systems, on the other hand, offer a low overall heat transfer coefficient (OHTC) value (0.5-1 watts per square meter per Kelvin [W/sq m-K]), or U-value, as well as a longer "no touch time" before intervention is needed, says Thurairajah Sriskandarajah, Pasupathy Ragupathy, and Venu Rao, of Subsea 7, in their paper "Design Aspects of Pipe-in-Pipe Systems for HPHT Applications" [OTC-27046-MS].

Some PIP systems are made of two concentric pipes (an inner pipe or flowline, and an outer pipe or carrier pipe) with centralizers, waterstops, and intermediate and end bulkheads. The centralizers are placed between the carrier pipe and flowline to keep the flowline centered, minimizing contact with the environment, which means the flowline is not directly exposed to the cold seawater, reducing the amount of insulation needed. The annulus between the two pipes can be filled with air or a passive thermal insulation, such as aerogels, to reduce heat loss. To improve thermal performance even more (U-value < 0.5 W/sq m-K), the annulus can also be made into a partial vacuum or the annulus gas can be changed, according to Subsea 7.

PIP systems also shield the flowline from hydrostatic over-pressure and potential damage from trawling, anchors, etc. Furthermore, they can enable the use of fiber-optic systems to log production data along the length of the pipeline, leveraging the availability of a dry annulus, according to Subsea 7's paper, as well as use fiber-optic sensors to detect and monitor pipeline deterioration, according to Subsea 7's Technology Manager, Gordon Drummond, in the company's publication, *Deep 7*.

Other PIP systems can be installed in bundles with or without centralizers. With bundled pipelines, the carrier pipe can host multiple inner pipes or umbilicals, which are allowed to slide along the length of the bundle, except at the ends where they are restrained by the bulkheads. These systems are useful when the subsea field design needs flexibility, such as areas with challenging seabed conditions (e.g. boulders) or areas that are highly congested, says Subsea 7. If greater thermal efficiency is required, a partial vacuum or reduced pressure in the annulus can be combined with an appropriate annulus material.

Recent developments have expanded the depth limits to 1100m for a carrier bundle and 1400+m for open carrierless bundle, according to Martin Goodlad, Subsea 7's strategic technology manager, Bundles, in *Deep 7*.

Installation

Bundled systems are towed out in sections, this has the benefit of increased installation weather windows and does not affect the PIP system during installation activities. For other PIP systems, installation offshore can be done using the reel-lay, S-lay, or J-lay methods. Though this may seem straightforward, the installation process can actually affect the PIP system post-lay, says Subsea 7's OTC paper.

During installation, the bending

moment capacity and residual out-of-straightness (OOS) of the pipe will change depending on the load transfer between the inner and outer pipe associated with each method. Post-lay, the carrier pipe is fully straightened. However, the flowline is more sinusoidal when using reel-lay, rather than S- or J-Lay methods. Also, during installation, with the vessel's tensioners carrying the carrier pipe load and the vessel's equipment carrying the flowline load, a residual axial compressive load is induced on the inner pipe that has been laid on the seabed. When this compressive installation stress is combined with the hoop stress induced by high internal pressures and the operating conditions, a high equivalent stress close to the pipe's yield stress can develop, according to the paper. Factor in the differential axial load and bending moment capacities of a section – a result of the variations in yield strength and wall thickness due to manufacturing process – and a localized axial deformation, wrinkling of the inner pipe wall, and eventual failure of the inner pipe can occur, particularly at weak sections.

Installation causes stress on the carrier pipe, as well. During installation, tensioners induce tension on the carrier pipe, and when the pipe is laid on the seabed, the tension is gradually relieved and the carrier pipe goes into compression. At the same time, hoop compression resulting from the hydrostatic pressure causes small axial tension, due to Poisson's ratio effect that will act together with the installation induced stresses, outlines the Subsea 7 OTC paper.

Corrosive tendencies

If the fluids produced from the HPHT field are corrosive, the PIP system may require corrosive resistant alloy (CRA) lined pipe for the inner pipe. Under these conditions, however, the PIP system can be installed using reel-lay with fresh water in the pipe, so that the internal pressure will prevent wrinkles in the CRA pipe from forming, despite the compressive forces induced during installation. The solution has been successfully applied during the installation of single lined pipe for the Guara-Lula project, and according to the OTC paper authors, the same solution can be adopted for PIP systems with CRA lined inner pipe. During normal operations, the high temperatures can also cause wrinkles, however, the effects of high temperature are overcome by the high pressure, during operation. Though, wrinkles can form when the system is shut-in and compression is induced due to the pressure dropping quicker than the temperature. But, if the residual curvature of the pipe has a nominal strain of 0.4% or less, the issue can be avoided; otherwise, a minimum internal pressure of 7-10 bar may be necessary to mitigate wrinkling issues during shutdown, says the paper authors.

High temperatures in the system can also affect the centralizers and thermal performance. Exposed to high temperatures, the centralizers can be susceptible to thermal creep and progressive deformation. This deformation can then lead to the insulation deforming, which would affect its performance.

How PIP systems are installed also needs consideration. Generally, a PIP system can be trenched and buried, completely rock dumped, or just laid on the seabed. But, as water depth increases, trenching and burying and rock dumping become prohibitively expensive. Along with how the pipe will be laid, engineers must also mitigate the pipe's tendency for upheaval or lateral buckling and walking-gradual axial displacement of the whole pipeline towards one end or buckle sites creeping from their originally formed positions, the paper says, resulting from pipe-soil interaction, seabed slope, axial ratcheting, and residual bottom tension.

To mitigate buckling, the pipeline can be "snake laid" to form control sites for buckling, laid over sleepers, spot rock dumped, or buoyancy units can be strapped to the pipe to supplement the formation of seabed induced buckling, say the paper authors. The curved section of the snake lay are triggers for buckle mitigations, as well as the sleepers and buoyancy units. To prevent excessive loading on riser connections, spools, and jumpers, walking tendencies can be mitigated by tying the PIP system to suction piles or anchoring the system with clump weights and tether clamps.

The pipeline bundle system expands the limits of HPHT flowline design, the high axial compressive forces generated by the high termperature are balanced by tension in the sleeve and outer carrier pipe. The balanced forces with the added weight of the bundle system mitigates the need for global buckling mitigation measures and therefore offers a cost efficient alternative solution.

HPHT fields can be demanding on the equipment used to produce from them. Engineers not only need to be concerned with the impact of fluid properties on host facilities, but also the properties of the pipeline used to transport them, and the condition in which the pipe is installed. OE

* Sriskandarajah, T., Ragupathy, P., & Rao, V. (2016, May 2). Design Aspects of Pipe-in-Pipe Systems for HP-HT Applications. Offshore Technology Conference. doi:10.4043/27046-MS

Getting smarter

Could we on the verge of embracing the industry 2.0 era? Intelligent energy, or the digital oilfield, is set to be discussed in Aberdeen next month. We take a dip into the debate.

Images from iStock.

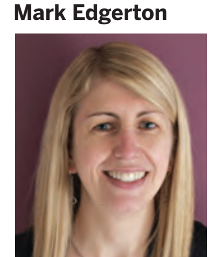
The opportunities around implementing intelligent energy (IE) technologies are quite vast and the potential just as significant for the oil and gas industry.

Be it automation in the drilling sector or unmanned facilities remotely operated by an integrated operations organization or better use of data analytics to improve production and maintenance efficiencies, many are keen to extoll the possible virtues of so-called smart systems or the digital oilfield.

But it seems like it has been so for quite some time. Could we finally be on the verge of embracing the oilfield 4.0 era (or even 2.0?), forced by low oil prices and a need to do things different?

Some certainly think so, even in the mature North Sea basin. “The current low oil price environment makes re-defining how we work, establishing new roles and centralizing analysis and decision-making even more imperative,” says Mark Edgerton, an asset manager for Chevron for the North Sea Alba asset.

Mark Edgerton



Helen Gilman

The benefits of adopting intelligent energy tools include real-time production optimization, improving the efficiency of reservoir surveillance and management, through integrating real-time data with advanced engineering technologies, Edgerton says.

Advanced statistical algorithms help enhance understanding of major equipment performance, improving reliability, run times and production efficiency. Data analytics is also increasing the efficiency and effectiveness of maintenance and integrity management.

In its simplest form, IE can help streamline work through repeatable processes, he says.

"All of these areas have a common theme that highlights the importance of connecting the right people to the right information to improve decision-making and reduce cycle time – which, in my opinion, will have the biggest business impact," he says.

So, what has hindered us in the past? We're working in a complex industry, with companies focused on managing safety, operational and financial risk, Edgerton says. "This can create a natural conservatism in implementing change." Change also takes time, he says.

Commercial and business models are not necessarily aligned to adopting IE, says Helen Gilman, VP within Wipro's energy, natural resources and utilities consulting practice.

"Developments in digital and other technologies are delivering opportunities for us to be more integrated in the way we work, but our commercial and business models are not evolving as rapidly as the technology," she says. Both Gilman and Edgerton will be speaking at this year's SPE Intelligent Energy conference, held in Aberdeen in early September. ***OE*** is a media partner of the event.

The industry has been making in-roads, however. Chevron, for example, has been working on its own digital oilfield program, i-field, for more than a decade. It was pioneered in the North Sea and US, with roots in production engineering and operations but with a "transformation philosophy that enhances and optimizes operating processes," Edgerton says. No doubt Chevron has even more up its sleeve.

Other areas where the industry has already adopted these technologies include in more efficient collaboration, improved data access and visualization and workflows, says Gilman, who has co-authored a paper looking at how to accelerate uptake of IE technologies. But, there's agreement more could be done, including within the drilling sector.

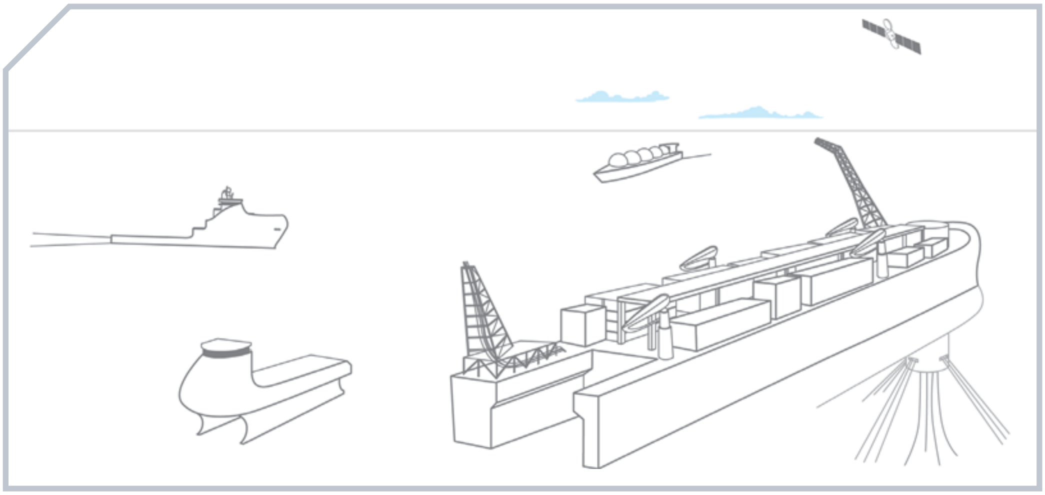
Drillfloor automation

Introducing automation into the drilling segment remains a slow process. Fionn P. Iversen, PhD, Chief Scientist, International Research Institute of Stavanger, is presenting a paper at SPE IE on the topic and, with his co-authors,* set out the main reasons why the drilling segment has been slow to adopt automation.

Fionn Iversen

The primary factor was industry fragmentation, he says. "We have multiple types of companies (operator, drilling contractor, service company, equipment supplier, etc.) and multiple drilling areas that each operate in (such as MWD/LWD, drill bit, motors, drill string, surface systems, instrumentation, etc.). By their past history, companies tend to compete in these areas, so we have different companies providing the same measurement, and the same services based upon that measurement. Therefore, it made business sense at that time to build proprietary systems, which unfortunately now hinders adoption of the open systems required for IE."

But, there's also a lack of understanding about what data and information is required, he says. "Advanced IE services exist, but are challenging to use, due to insufficient available information." In other words, there needs to be sufficient instrumentation to detect the state of the operation and then appropriate and accurate measurements to provide sufficient



DNV GL's *Solitude* concept. Image from DNV GL.

He says using a clean sheet and an objective driven design is the way forward, not working from the last best design and tweaking it. Also, concepts needed to be included as the feasibility study and concept selection phase to ensure that operations perspectives are clear and included in the commercial framework for a project.

As an example, DNV GL has developed the *Solitude* concept – based on an unmanned FLNG installation.

While the tough LNG market might not see *Solitude* come to market in the near-term future, the concept has been widely embraced by the industry, Boyle says. What's more: "Many elements of Solitude can be implemented independently and some are already available," he adds. "For example, operators control subsea installations and simple, fixed offshore installations from shore. With continuing advances, unmanned offshore installations are a natural development."

Indeed, this type of activity is already happening in the subsea sector, where minimal intervention strategy is being pioneered, Boyle says.

"In other industries, such as automotive, the use of data sensors to determine effective service activity is gathering pace, while further disruptive technologies in the form of the Google car will further step change IO use," he says.

reliability of model prediction and process optimization for the operation in question.

Furthermore, IE use depends on open digital communications, which a company might perceive as a threat to its constructed barriers. "For drilling systems automation, SPE's Drilling Systems Automation Technical Section's (DSATS) first proposal was to adopt Object [Linking and Embedding] for Process Control Unified Architecture (OPC UA) as an open communications protocol. That proposal was about six years ago, yet only now are we seeing emergent OPC UA systems for drilling (*OE*: March 2015). The adoption rate is low, in part because existing companies prefer to operate behind barriers."

There's also a lack of a technical roadmap, he says. "For any business to commit funds to developing and supporting systems automation, it has to see the long-term strategy within the industry," Iversen says.

Systems engineering also needs to be addressed. "Practices are really not employed in the drilling industry at the level one would expect," he says. "Systems engineering within silos does occur, but systems engineering does not occur at an industry level. It is therefore difficult to build a vertical model that is automated from the wellsite to the enterprise level."

Finally, it's about metrics and how you can measure the impact of IE on drilling. "The ultimate goal of IE is, possibly, to develop a systems engineering approach to drilling, and then one has to measure KPIs (key performance indicators) representing adherence to optimized constraints. This means information sharing between multiple companies, which is difficult in a fragmented industry operating within silos.

"This is a multi-level scheme that has been proposed by various authors,* based on ISA-95, that is applied to various industrial manufacturing enterprises. Essentially drilling optimizes to a series of constraints. One example would be allowable equivalent circulating density (ECD), which depends on the operating window, bounded by fracture pressure and pore pressure – a KPI would be how well this ECD is maintained. Another might be allowable tripping speed at hole depth, which varies depending on the allowable margins between surge and swab speeds and fracture and pore pressures respectively."

Unmanned movers

Another area of intelligent energy focus is removing people entirely from the work site, with completely unmanned facilities, could also be a way the industry works more smartly in the future.

"Removing people is a fundamental principle of inherently safer design," says Peter Boyle, a leader within the UK risk advisory group of DNV GL. "This in turn produces additional design, weight and cost savings."

Peter Boyle

Boyle says that an aversion to risk, the race to be second, has impaired the oil and gas industry's ability to innovate in this area. But, the "brutal wake-up call" of the oil price slump, could open the door to more use of intelligent energy technologies, such as integrated operations, or IO, where platforms are operated remotely.

What next

Gilman says that new technology start-ups could help inject some innovation into the oil and gas sector. But, she says that it's also about existing players and those looking to take on IE technologies working together differently.

For Edgerton it's quite simple: "IE technologies help us enhance our understanding of complex systems and to optimize them. Reducing complexity helps overcome one of the biggest barriers to changing business performance. IE solutions are a methodology, not a goal, and remembering this will help as companies look to deploy tools and apply new concepts to improve the business." **OE**

* J.L. Thorogood, Drilling Global Consultant LLP; J.D. Macpherson, Baker Hughes; R.A. Macmillan, National Oilwell Varco.

DRILLING

Preventing bugs

The spotlight now shines on how to better integrate multiple complex software systems during drilling rig construction with beneficial results.

Songa Endurance. Photos from Songa Offshore.

Software drives almost every system we use in the 21st century, from our cars to telephones and even home heating systems.

Yet, when a rig leaves a yard its plethora of interconnected software systems haven't had the same level of scrutiny as the hardware. Software version changes, which can be frequent, are not traced or checked to anything like the level hardware components are traced, from materials source through manufacturing, delivery and testing.

The result can be lengthy commissioning, as bugs are tracked to their source and ironed out, and even complications during operations.

For the past 10 years, DNV GL has been researching and working towards an integrated software dependent systems (ISDS) standard (DNV-OS-D203) to prevent such glitches. The aim is to enable full tracking of the quality and version control of all integrated software systems, so that the yard and the user knows the status of all systems, the latest updates, if any still require close-out at the yard, at any given time.

OE reported on a pilot project DNV carried out with Seadrill back in 2010 (*OE*: October 2010), which was one of the first trials of the methodology. Seadrill had applied the technology retrospectively to a then recent newbuild.

Cat-D quartet

Now, ISDS has been put to a bigger test. ISDS has been used on Songa Offshore's four new sixth generation Cat-D semisubmersible rigs, built to be used by Norwegian oil firm Statoil for work on the Norwegian Continental Shelf. Statoil, when it ordered the rigs, made the requirement that ISDS would be used as part of the newbuild program.

All four units have been delivered, with three, *Songa Equinox, Songa Encourage* and *Songa Endurance*, now working offshore Norway, while the fourth unit, the *Songa Enabler*, was delivered late March and is due to start working, after its voyage from Daewoo Shipbuilding & Marine Engineering's yard in South Korea, in Q3 this year, on the Snøhvit field.

Although the project experienced delays and overruns at the yard the implementation of ISDS combined with the independent hardware in the loop (HIL) testing performed by Marine Cybernetics has been seen as a success.

The *Songa Equinox* was the first rig to go into service, in December 2015. "The ISDS and HIL testing done on the Cat-D project has definitely made a positive difference for the reliability of the integrated systems in the scope of ISDS," says Trond Jan Øglend, E&I Engineer for Songa CAT-D OPS Prep. "Cat-D has very complex software integrated systems and is performing very well; by now we would normally have had to deal with a lot more software integration issues."

Change management

So, why do this? Normally, a rig is commissioned and delivered, and its status at that point sets a base line, whatever state the software systems are in, which is traditionally not part of the yard's remit. This means every rig's systems, even if they are part of a newbuild program of multiple sister rigs, can end up being different as changes can be made to one rig, but not another.

"Before, you would receive a rig and there would have been no software control," says Martin Coward, engineering manager for the Songa Cat-D project. "We have got this version, but has it been tested? With what software was a particular function tested? If something was changed during commission how does anyone know? Normally, someone comes on and picks up the functional description for X to do Y. But if you have changed the software, there is no guarantee that X will do Y. It is very easy to make a small

change that could impact on someone else's systems without knowing."

Patrick Rossi, DNV GL ISDS project manager for Cat-D comments: "Tracking tools enabled by ISDS can also be used for decision making and staffing of needed software resources for approval and validation of changes."

As software is often unfinished when systems are delivered to the yard, interfaces are not always completely engineered or tested, so software interfaces need to be coordinated at the vessel level.

Software updates are also always happening during construction: tuning, bug fixes, changes to software requirements (thousands of changes on hundreds of different programmable logic controllers (PLCs) and computers); so the tracking and timely (successful) testing of integrated software systems is a real challenge.

The original manufacturer of the equipment also sometimes sends updates to their firmware that are not requested by the project and may cause unstable conditions and problems during construction and commissioning, if they are not coordinated and planned.

Furthermore, software is not always properly addressed during design/reliability analysis; ISDS RAMS requirements highlight the need for software focus and track the outcomes of failure modes throughout the project. The list of integrated software systems onboard the Cat-Ds helps illustrate the complexity involved:

- Aker Solutions: Drilling Control System (DCS): Tool pusher and driller control panels plus anti-collision = 35 programmable logic controllers (PLCs), several servers and industrial computers and HMI software.
- Cameron: Well control: Blowout preventer (BOP) plus diverter/HPU = 9 PLCs
- Kongsberg Maritime: Vessel Management System/Safety systems: Power management systems (PMS) plus dynamic positioning plus fire and gas plus Emergency shut-down systems = 32 PLCs and several Microsoft Windows-based operator stations
- ABB: Drilling and thruster variable frequency drives (VFDs) = 21 PLCs and 9 Microsoft-based systems

"All of the above PLCs and computers also come with manufacturer's firmware (which is low level manufacturer software), so actually there are more sources of software to be aware of," Rossi says.

Implementation

ISDS implementation on the Cat-D rigs was done in such a way that as each new rig was rolled out, learnings from the last rig were transferred to the next rig, and as new learnings were introduced in each new rig, they were in turn rolled out across the previously built rigs.

Initially, the ISDS scope hadn't included the main engines, but this was brought into the system as it was seen as being a mistake not to include them.

The result is a fleet working on the same version software systems and shorter commissioning time, Coward says. "It has been hard work but it has been worthwhile," he says.

With ISDS, all the software systems are tracked, during the build, commissioning and post commissioning so that the current as well as any past setup can be seen.

Having the documentation which shows which version of software is being used at any one time means that during the build, if an interface isn't working, it is easier to tell a particular manufacturer or vendor what version of software they need to comply with in order to make the interface work.

This gave Songa Offshore far greater control over supplied software. Standard supplier software change management procedures were improved, more software faults were identified before their usual discovery phase during operations, and tracking the status of software design documents was much easier.

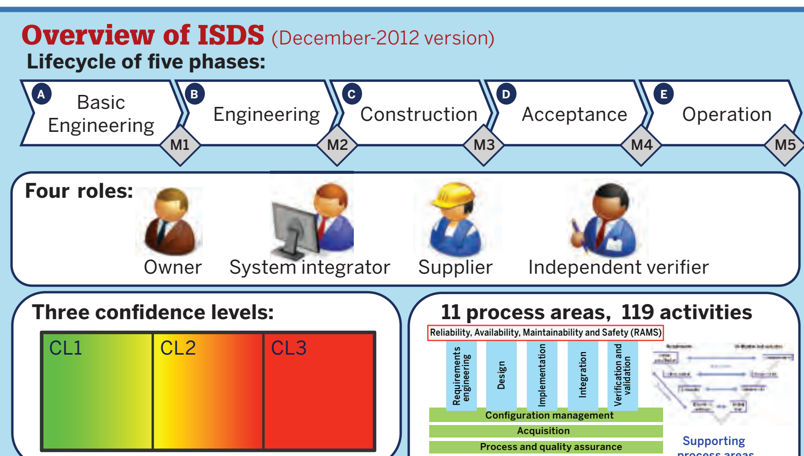
"It [ISDS] also helps in the future when we come to test anything we can show this is where we were at that point in time and how we got there. If there are any changes, we can go back to the last point we know it was all working," Coward says.

"Should there be an accident or some equipment damaged, the first thing anyone wants is to go back to a base line that would show everything has been tested and working. In the past, that would be delivery."If we changed something on the fourth rig, we ensured that we followed through on the third, second and first rigs," he says. In fact, the system is designed so that any change made, if it's applicable to previous vessels, needs to be rolled out to the other vessels before the task can be closed out.

This means that you don't end up with four rigs each with their own systems," Coward says. "It is a lot of work, without a doubt. With so many vendors interfacing with each other, it was a lot of work and we took it to the n[th] degree. But it has definitely been a benefit."

"A tremendous amount of work by an entire dedicated team preparing all of the rigs for Norway was done to ensure a timely acceptance phase; many things can go wrong and having ready, stable, completed software also plays a key role. For CAT-D the acceptance phase was completed in four weeks which is a noticeable achievement for such sophisticated rigs." says Mark Bessell, Songa COO. OE

Songa Equinox



ISDS process overview. Image from DNV GL.

Using wired drill pipe to drive down well cost

Drill floor operations. Photo from NOV IntelliServ.

Wired drill pipe has been a long time coming. As operators look at cost savings across the full life cycle, the benefits are now being recognized, says NOV's Leon Hennessy.

Wired drill pipe (WDP) is conventional drill pipe modified to accommodate an inductive coil embedded in the secondary shoulder of both the pin and box end. These coils are connected via an armored, high-strength DataCable embedded inside each tool joint, enabling high-speed downhole data to be transmitted across the drill string. DataLink sub-assemblies, typically placed every 1500ft along the drill string, clean and boost the data signal for optimal signal-to-noise ratio along the network.

The main benefit of WDP is to enable a reduction in telemetry related flat time, i.e. any time that is spent off-bottom waiting on mud pulse telemetry to send a signal to surface. Any drilling operation using measurement while drilling (MWD), logging while drilling (LWD) or rotary steerable systems (RSS) tools in the bottomhole assembly (BHA) will often see this time occur. This could be during surveys, on connection or mid-stand, during check/roll surveys, while downlinking off-bottom or shallow hole testing, during pressure testing, formation integrity testing, leakoff testing, signal trouble shooting, etc.

Although individually these instances makeup a small time component, once accumulated across an entire well, this value can add up to multiple hours or even days. Oil major Total, in Norway, recently published telemetry time reduction results (ref: SPE 178863, 2016) that it realized from implementing WDP in its operations at the Martin Linge field, where there was a 82% reduction in normalized telemetry time per well.

WDP offers other benefits, including increasing rate of penetration (ROP) through high frequency, low latency downhole data, allowing real-time optimization, and enhanced real-time visualization and monitoring of equivalent circulation density. These benefits can be enhanced further with the use of along-string measurements including pressure measurements, to manage wellbore conditioning and time spent circulating off bottom. Real-time data can help improve well placement and geo-steering on-the-fly and reduce unplanned bit and BHA runs by detecting

Figure 1 – Well A Telemetry Time Savings Analysis (hours)

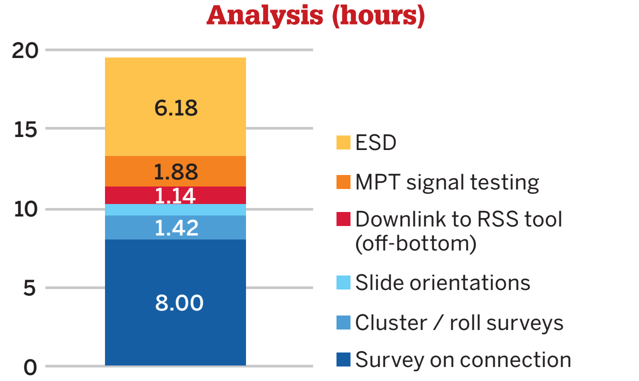
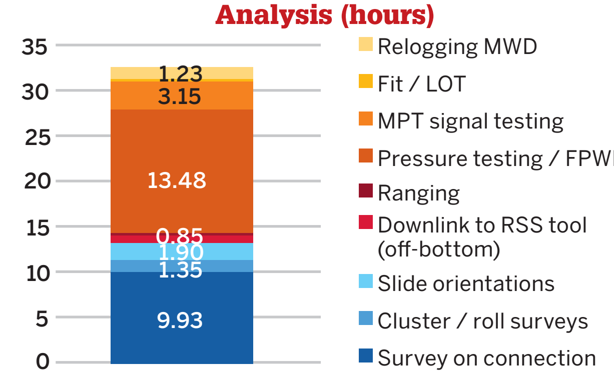


Figure 2 – Well B Telemetry Time Savings Analysis (hours)



drilling dysfunctions early.

A recent five-well development campaign on E.ON Ruhrgas' Babbage field (ref – SPE 178798, 2016) used WDP to add value. Apart from the telemetry time savings of 25.8 hours per well, a reduction in runs to total depth (TD) of more than 40% was identified, as well as a 200-300% increase in ROP.

Total's operation on Martin Linge also saw increased reservoir drain of 1000m through ECD (equivalent circulating density) limits optimization versus shoe strength. It also had a nearly five-fold increase in ROP, instant activation, and confirmation and de-activation reaming tools. Enhanced reservoir appraisal was enabled through use of seismic while drilling look ahead, activation and data transfer through WDP, which net an increased drain in the sweet spot.

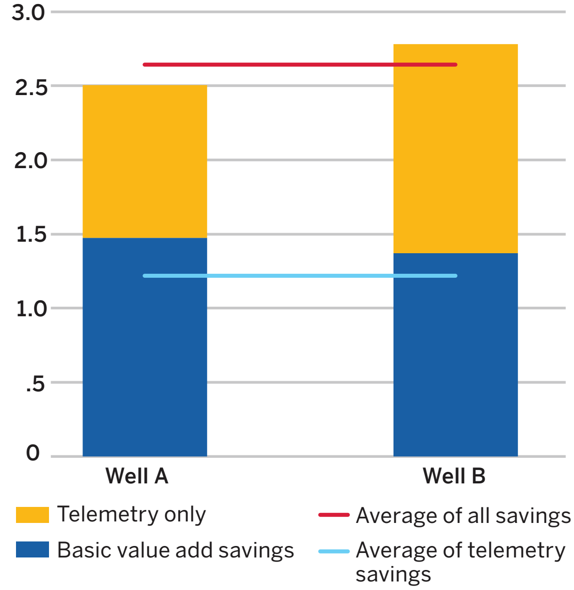
While the upfront costs might seem like a hurdle, calculating the costs against the benefits needs a closer look.

WDP cost, or cost to a project, can be outlined as:

- Cost of WDP – The capital cost or rental cost to the project
- Inspection, repair and maintenance (IRM) – Additional electrical inspections, replacement of coils and DataCables, which measured in the business case and is an incremental percentage increase at the nominal inspection cycle for a particular project
- Telemetry network management – Any costs associated to managing the network including service company charges for supplying the interface sub so that all their MWD, LWD and RSS tools operate on the network
- Wired Tools – Wiring cost or additional rental cost of wired tools in the BHA compared to conventional (non-wired) BHA tools
- Network maintenance and uptime – The small time component related to any maintenance on the network

For the cost of WDP, wired tools and the IRM components, these can be considered incrementally above the traditional cost of the string since these are existing costs.

Figure 3 – Telemetry and Value Add Savings (days)



For an initial value analysis, it is acceptable to look at nominal well designs and project inputs. If further data is available, it is important to conduct proper off-set well analysis to clearly verify the telemetry time savings and further model the potential value-adds against the well construction challenges. Traditionally, any value-add assessment will include a Monte Carlo analysis to fill any probabilistic scenarios, such as an increase in on-bottom performance in order to provide a more realistic output. Typical data used are BHA designs, daily drilling reports, bit run reports, MWD and mud loggers' end of well reports, well summaries and definitive surveys, time-based drilling mechanics logs, activity summaries with planned vs actual time depth curves and slide sheets and landmark exports.

The business case

Below is an example from an ongoing field development project in Asia Pacific. The business case has been supported with a two off-set well analysis.

The following main assumptions are considered when calculating the net value:

Figure 4 – Operating Expense per Annum

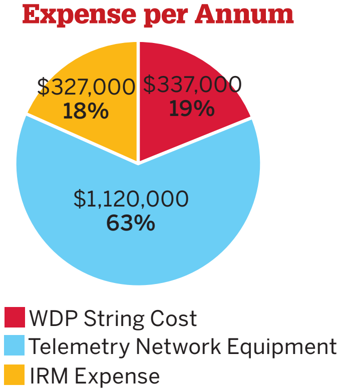
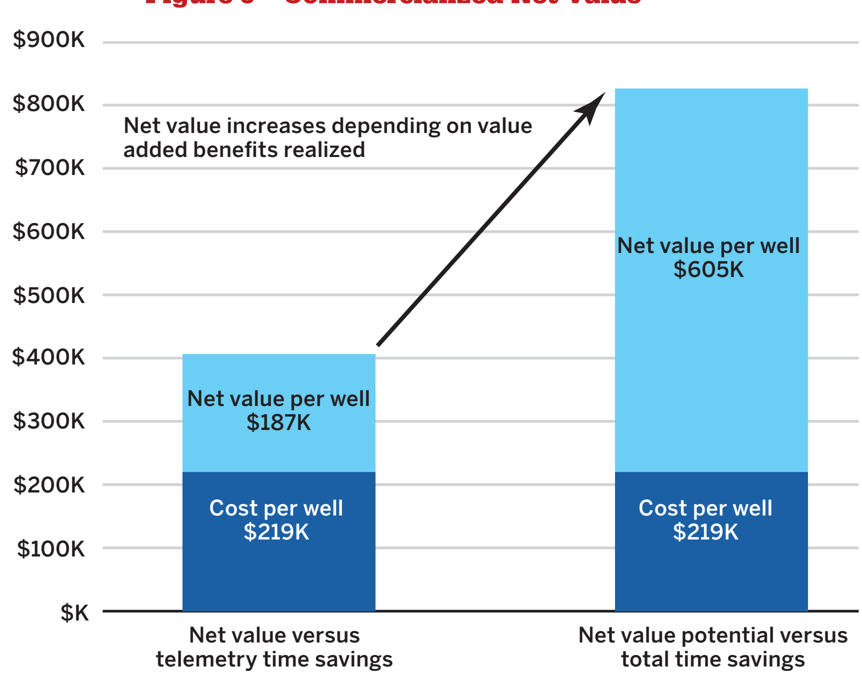


Figure 5 – Commercialized Net Value



- A five-year nominal string life and depreciation schedule
- US$350,000 nominal spread rate
- 45 average day wells
- A rotating hours nominal inspection cycle interval per 2500 hours
- Incremental investment costs considered from the provided BHA as listed in the analysis

Identify savings potential

The well analysis of wells A and B identified multiple telemetry time events, which were quantified from the time-based logs and summarized in Figures 1 and 2. The telemetry and value-add savings are outlined in Figure 3. The focus of the analysis is purely on the automatic telemetry savings which does not discuss value-add savings in detail.

Incremental cost and operational expenditure

The cost of WDP takes into consideration the incremental purchase cost of a wired string, i.e. the cost above the conventional or unwired string. The main string components considering a nominal well design as referenced above include:

- 5 7/8in wXT57 Range 2 – WDP and wired HWDP
- 6 ¾in wired drill collars, NMDC and ponys
- 8in wired drill collars, NMDC and ponys
- 6 ¾in and 8in wired stabilizers and reamers

Additional IntelliServ network integration equipment:

- Integrated top drive DataSwivel
- Wired saver subs
- Surface cabling (from DataSwivel stator through service loop and down the derrick to the mudlogging/MWD unit)

The total incremental cost of the wired BHA was $1.68 million, or when depreciated over the life of the string on this project, $42,000 per well.

In addition, there are several telemetry components provided by IntelliServ to create the high-speed telemetry network using the wired drillstring. This includes a Network Controller, the DataLinks, WDP inspection, repair and maintenance, MWD interface subs, and field technicians.

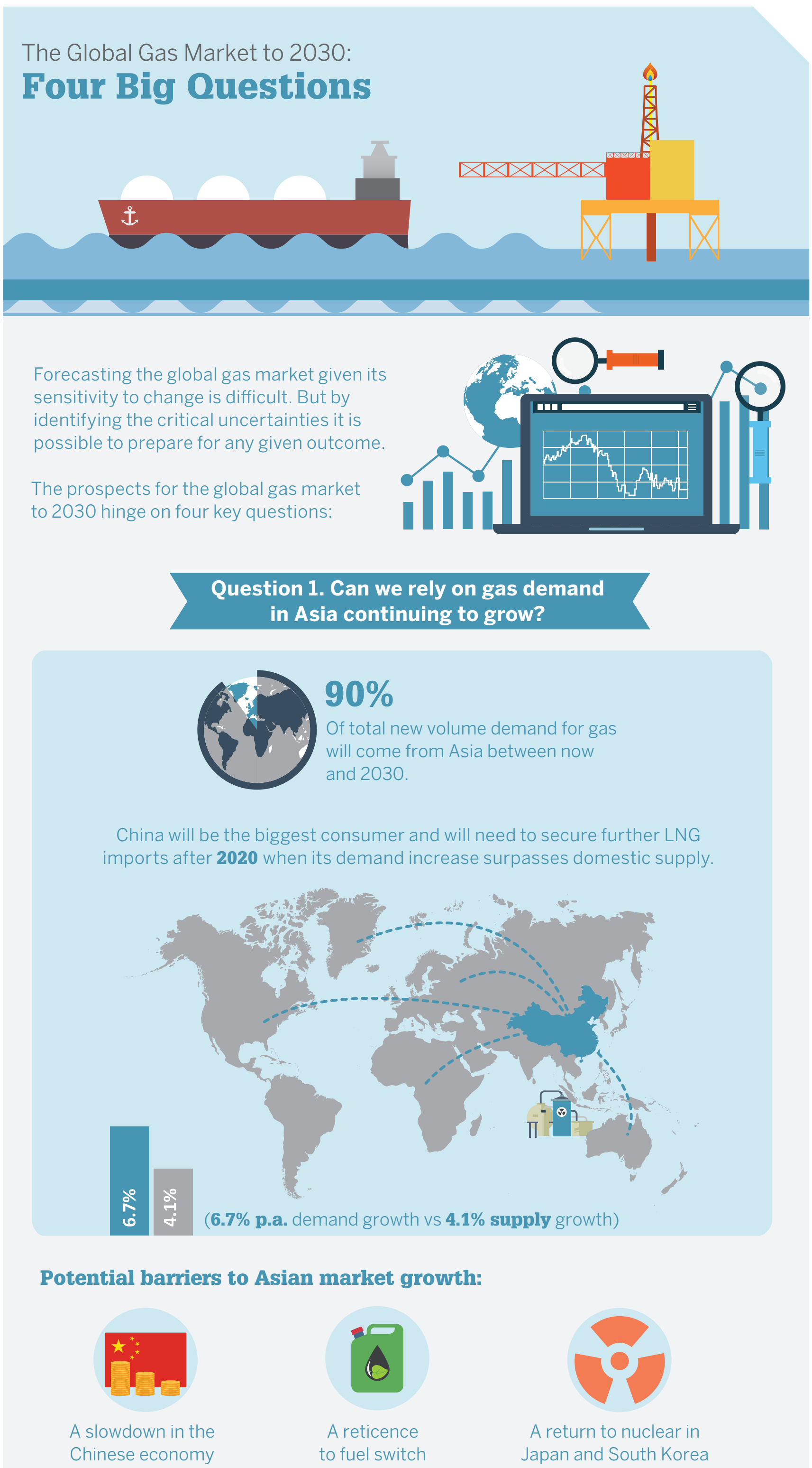
The total normalized annual cost of owning and running WDP is outlined in Figure 4 and equates to $220,000 per well.

Commercialized net value

Furthermore, Figure 5 shows that after paying for the $220,000 per well, $187,000 of savings will be realized. Given this is considering simply the telemetry related savings alone, any further value driven by WDP – for example value-adds such as increased on bottom performance, reduction in Bit/BHA runs etc. – will further increase the net value realized. In the cases referenced in this discussion for Total, Martin Linge and E.ON Ruhrgas, Babbage the value-adds were compelling and measurable. **OE**

__Leon Hennessy__ is business development manager for Asia Pacific and Middle East Regions for IntelliServ. With a career spanning drilling operations and directional drilling, Leon has hands on experience throughout the life cycle of well construction. Prior to joining NOV, he founded an integrated services business providing geology, reservoir, drilling engineering, directional drilling and operations services.

Drilling depression



There's no sign of let up in the global drilling market, according to McKinsey Energy Insights. The gloom is, however, spurring improvement initiatives.

There's no doubt the global drop in oil prices has hit the offshore drilling industry hard – and during the toughest conditions for decades, rig owners are having to use their ingenuity to remain operational.

Total exploration and development capex investment was down 26% from 2013 to 2015, with exploration the first area to be cut. Latest forecasts suggest a further cut of 20-30% between 2015 and 2016 – a reduction that will directly impact the demand for drilling services.

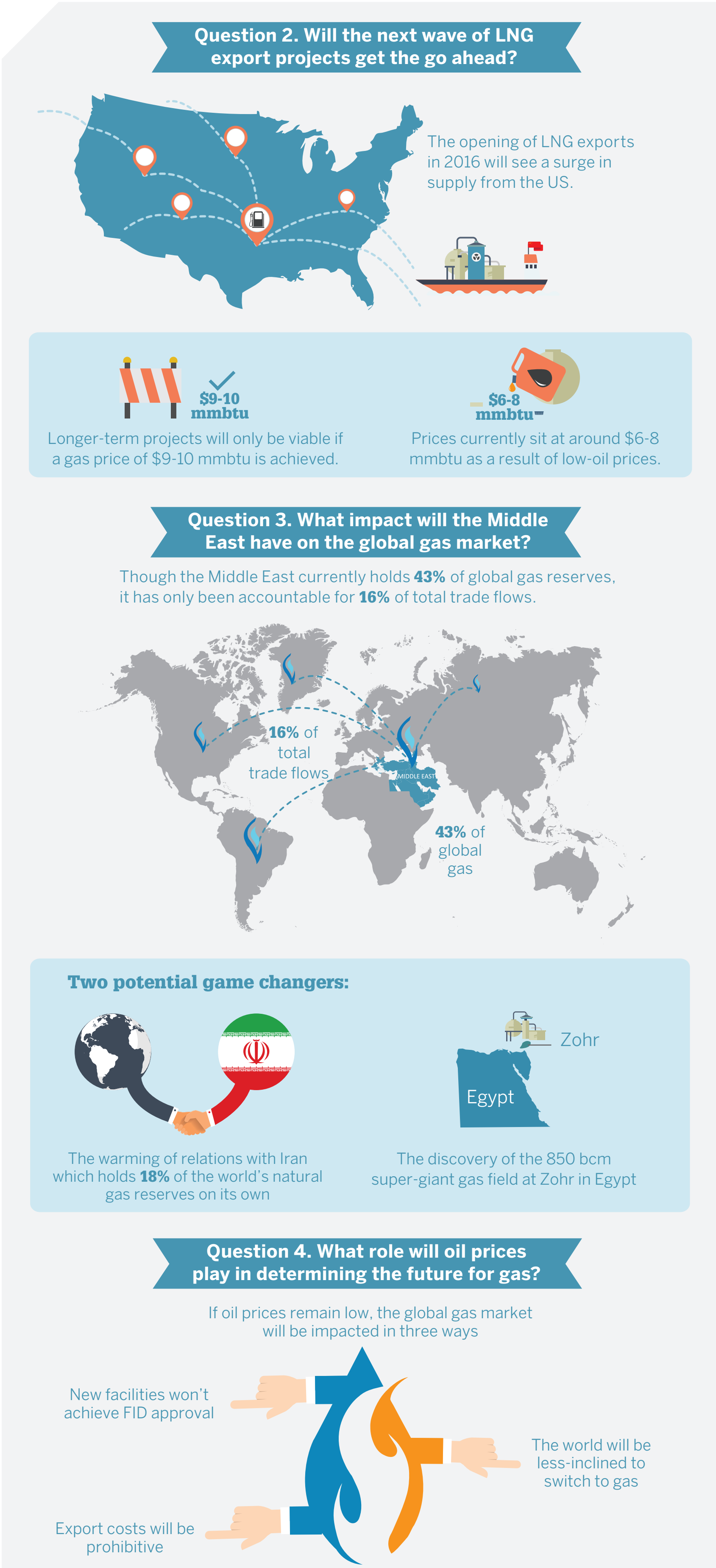
New field developments have been deferred or cancelled by all of the major players as a result of cash constraints and uneconomical forecasted returns. As a result of project postponements, operators are reducing rig obligations by deferring and cancelling contracts – despite serious legal, reputational and financial ramifications.

New contract volume declined by a massive 50% from 2013-2015, leading to a rise in uncontracted rigs and greater competition for the few remaining contracts. The share of idle rigs has grown by 15-19% since Q1 2013, leading to a significant increase in cold-stacking and retirement.

Contract duration, too, has fallen for both floating and jackup fixtures, by an average of 32% and 33%, respectively. The decline reflects uncertainty in future prospects as more expensive and complex projects have been mothballed.

As the gap has widened between supply and demand, day rates have been lowered, reducing the value of active contracts by 23% from a high in Q4 2014.

The share prices of listed rig owners have dropped – in some cases by as much as 60-80%, as the financial market assesses the impact of lower day rates on future cash flow.



Infographic from McKinsey Solutions. These projections are taken from Energy Insights' Global Gas Outlook to 2030. For your free Executive Summary of the findings included in the report visit www.gasoutlook2030.com

While revenue backlogs have dried up and debt has matured, operating costs have remained, leaving the industry with a cash deficit of almost US$6 billion by the end of 2015.

Despite steps to cut planned capital expenditure, this net cash position looks set to remain negative as operating costs remain high and contracted revenue projections continue to decline. (Further financial analysis of the current market can be found in Energy Insights' Offshore Drilling Corporate Performance Analysis Report).

The industry isn't sitting idly by as revenues are decimated – mindful of their limited control over future revenue, rig owners are cutting costs, renegotiating contracts and using short-term bankruptcy to restructure their debts.

More innovative operational cost cutting measures include minimizing manning levels, moving rigs out of oversupplied regions, cluster-stacking fleets and embracing partnership as a route to improving project management.

Meanwhile overheads are being cut via reductions in wages, dividends and corporate expenses, the retirement of non-performing functions, and consolidation of corporate premises.

If there's any positive to be taken from the current market conditions, it's that rig owners have been forced to embrace a more agile, collaborative, streamlined way of working.

It should position them well to benefit from these tough decisions as and when the upturn does arrive. OE

***Ryan Peacock**, based in Houston, works at McKinsey Energy Insights as an oilfield service manager supporting clients in market due diligence, market forecasting and analysis. He was previously an engagement manager for McKinsey and Company. Peacock holds a PhD in chemical engineering from Stanford University.*

***William Wu**, based in London, works for McKinsey Energy Insights as an analyst. Wu previously worked in structured finance for Leighton Holdings and investment management at Platinum Asset Management. He holds a master's in finance and private equity from the London School of Economics.*

OE REGION

DUTCH OFFSHORE

Renewable renaissance

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14 Joined up separation Dutch firms Frames and Royal IHC are taking a step into the deep, quite literally, as well as figuratively. Elaine Maslin sets out the detail.

A SIF monopile foundation installed offshore. Photo from SIF.

Growth industry

Offshore wind is a growing business in the Netherlands and it's set to get even bigger, reports Elaine Maslin.

This year, the Dutch government put out to auction the 700MW Borssele 1 and 2 offshore wind zones, off Zeeland. Some 38 bids were submitted, including one from a consortium including oil major Shell. Mid-July, Danish energy firm DONG Energy has laid claim to winning both. A further round of sites, Borssele 3 and 4, will be auctioned in September. The two farms will have 350MW capacity each, 22km off the coast of Zeeland, in 14-38m water depth.

Taken alongside the approval of a law which paves the way for new transmission infrastructure, enabling up to 3.45GW of capacity by 2020, and the ongoing construction of the mega-600MW Gemini park (*OE*: September 2015), it's all looking very positive for Dutch offshore contractors.

However, Dutch firms haven't waited for work off their own shores before getting stuck into this market. And, according to a report by Dutch bank Abn Amro, by taking on board lessons learned in Denmark, Germany and the UK, the Dutch can now take a leap forward in terms of efficiencies and costs in a more mature offshore wind market.

Following an increasingly popular model, Dutch contractors are also becoming shareholders in projects, deepening their commitment to the business. Van Oord, for example, has a 10% stake in the Gemini wind park, which it is not surprisingly also a large contractor on. It is also part of the consortium with Shell, which submitted one of the bids for the Borssele areas, with partners Shell and Eneco.

Companies are also consolidating their expertise. Van Oord took over Ballast Nedam Offshore to integrate into its offshore wind business unit, as it saw the opportunities in the market, says business consultancy EY. More recently, Boskalis completed the acquisition of the offshore wind activities of VolkerWessels, who it had been working in 50:50 partnership with as Offshore Windforce, which Boskalis now owns outright.

Companies are also working together. Earlier this year, the GROW program (Growth through Research, Development and Demonstration in Offshore Wind) was launched. It is a consortium of about 20 organizations in the Dutch offshore wind sector, which aims to reduce the cost of offshore wind energy and reach 7 eurocents per kWh by 2030, reflecting a 50% reduction compared to 2014. It hopes to make offshore wind able to compete with other renewable and fossil energy sources – without subsidies.

With the downturn in oil and gas, being able to move over to offshore wind has offered a new source of revenue for some firms, says EY. "One of the main alternative sources of revenue for fleet usage is offshore wind," it says.

Damen's head of business development Peter Robert certainly sees the opportunity. "Wind turbine capacity has grown 41.1% from 2010 to 2015," he says. "In 2015, the average capacity of new wind turbines installed was 4.2MW, a significant increase from 3MW in 2010, reflecting a period of continuous development in turbine technology to increase energy yields at sea. The deployment of 4-6 MW turbines seen in 2015 will be followed by the gradual introduction of 6-8 MW turbines closer towards 2018."

But, Arno van Poppel, managing director VBMS, now part of Boskalis, says, "The biggest challenge is reducing the levelized cost of energy (LCOE). This cannot be achieved by just one party. It has to be achieved by the entire supply chain. This requires different ways of cooperation within the supply chain. There's no one party that can delivery everything. We are looking for the long-term. If we support this, if we can achieve growth with a LCOE that can compete with fossil fuels, without support from subsidies, it will be a step change." ■

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Supplement editor, Elaine Maslin, emaslin@atcomedia.com
Advertising sales, Arthur Schavemaker, arthur@kenter.nl
Art and production, Bonnie James
Reprints, Rhonda Brown, rhondab@fosterprinting.com, +1.219.878.6094
AtComedia, 1635 West Alabama, Houston, Texas, 77006-4101, USA
Tel: +1-713-529-1616 • Email: editorial@atcomedia.com • www.oedigital.com

Setting sights on EPCI work

Seaway Heavy Lifting is moving into a new league in offshore renewables, taking on contracts on an engineering, procurement, construction and installation basis. Elaine Maslin found out more.

Handling foundations and transition pieces. Photos from Seaway Heavy Lifting.

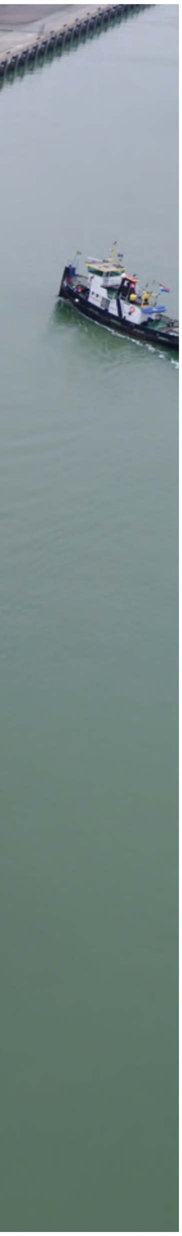
Dutch offshore contractor Seaway Heavy Lifting (SHL) is set to shift up a gear in its offshore wind expertise.

The firm, which owns and operates two heavy lift vessels, already has an impressive string of offshore wind transport and installation projects under its belt, having been an early mover into the offshore wind business. To date, it has installed 15 substations, 450 monopiles and 275 transition pieces, weighing a total 416,000-tonne. It is also setting records in terms of foundation installation rates.

Its latest awarded project, however, the Beatrice Offshore Wind farm, a 588MW wind park in Scotland's Outer Moray Firth, will see it step up to take on an engineering, procurement, construction and installation (EPCI) role. Fabrication contracts have been issued to the subcontractors Bladt, SIF (see page DO-6), BiFab, Smulders and EEW for the fabrication of foundation components, i.e. jackets and piles. Offshore construction is due to run from April 2017 through Q3 2018, using SHL's heavy lift vessels *Stanislav Yudin* and *Oleg Strashnov*. SHL, in alliance with its 50% owner, Subsea 7, will lead the design, engineering, fabrication, transport and installation of the park's 84 monopile foundations and two offshore transmission stations, plus array and export cables.

SHL CEO Jan Willem van der Graaf, who led Subsea 7's renewables business, before it was transferred into SHL in 2013, is keen to stress that Subsea 7 will very much take a back seat role on the project. Subsea 7 brings execution power and financial power. But, SHL has been tasked by Subsea 7 on the project and has been both building up itself and its processes internally, as well as working with contractors, such as engineering firm Atkins, he says.

"It's all about managing the risks and having some of your best people on the project. Some have come from Subsea 7, some from SHL and some from the market. It means having better document



Installing the SylWin converter station.

control systems, very good contract management, making sure everything runs on time and people communicate." Van der Graaf is confident this can be done. "We have done a lot of large subcontracting before, and installation-wise, it's not a big issue for us. It's a repetition of one installation 84 times. Logistics will be important, being there on time, but it's not difficult work. It's also doing it faster."

SHL has been working up to the job. It has a track record of renewables projects under its belt.

A notable project was the installation of the 14,000-tonne SylWin alpha converter platform in 2014, using a novel floatover method. The jacket was installed using SHL's crane vessel *Oleg Strashnov*. Then, in spite of the *Oleg Strashnov*'s high capacity, additional buoyancy was used to aid the lift of the 14,000-tonne converter station topside. This involved buoyancy tanks and additional buoyancy on the pontoon, which transported the converter station and was then positioned between the jacket legs and ballasted to lower the topside onto the jacket. This was the only North Sea floatover installation known to have been conducted, van der Graaf says.

Jan Willem van der Graaf

SylWin is one of the world's largest converter platforms, installed west of Sylt, offshore Germany, and serving as a "power socket" for the DanTysk, Sandbank and Butendiek wind farms, which together comprise 240 wind turbines and represent a generating capacity of 864MW. SHL was the lead contractor and used fellow Dutch firms Dockwise and Mammoet for the job.

Van der Graaf says that SHL has also been setting records when it comes to monopile foundation installation. On the Dudgeon wind farm, in the UK offshore, it has been doing monopile and transition piece installation in less than a day from the same vessel, instead of using one vessel for each task, he says. "For us the transition piece is a matter of hours, it doesn't pay to have a separate spread," he says.

Looking ahead, he says it will be important to keep up with growth in the renewables business, especially with the size of foundations, moving towards 10m-diameter, and turbines, already at 8MW units, and how these are accommodated and what equipment is used with them. "I think we need to get ready for growth in size in the future, that's part of the trick to making wind power cheaper," he says.

But, SHL, which has some 800 staff, about half based offshore, is far from abandoning its oil and gas business. Last year, for example, SHL completed one of the biggest lifting campaigns in the North Sea, to help install the Cygnus field facilities in the southern North Sea. This involved lifting in place four platforms, one of which set a record for SHL. The process platform topsides weighed 4700-tonne, the most SHL's *Oleg Strashnov* had ever lifted.

The firm has never been limited to the North Sea either. In 2015, SHL's vessels moved from Mexico to Brazil, to the North Sea, then the Arctic, before going back to the North Sea then on to Nigeria.

Renewables offers a stream of work to balance out oil and gas work, including decommissioning, van der Graaf says. With the oil and gas industry in a "holding pattern," renewables work is welcome business. Having flexible vessels helps. The 30-year-old *Stanislav Yudin* recently had a US$50 million upgrade to make it suitable for use for another 15 years. The *Oleg Strashnov*, delivered in 2011, is still relatively new.

But, while moving into an EPCI is the goal, SHL isn't looking to take design in-house, preferring to use others for what they're good at. "We do what we're good at," van der Graaf says. ■

Increasing capacity

Dutch monopile manufacturer SIF already produces the equivalent to the Eiffel Tower every 2.5-3 weeks. It's looking to increase that capacity further, reports Elaine Maslin.

SIF monopile offloading. Images from SIF.

Dutch fabrication group SIF hasn't had the attention it deserves, possibly because it's producing the hardware for offshore wind farms and offshore oil and gas platforms that gets the least attention.

That's because at least half of it sits under the water. Yet, having made the conscious decision to move into the offshore wind industry in 2000, as its traditional markets in pressure vessels and large cylinders moved overseas, SIF now appears to be at the leading edge of the fabrication pack.

It's not only gearing up to produce the industry's largest monopile wind foundations, it's also churning out a lot of them – 1500 to date and at a current rate equivalent to the weight of the Eiffel Tower every 2.5-3 weeks – as well as transition pieces.

The firm, which started out in 1948 as a metal working outfit (Silemetal) for large vessels, is now investing some US$70.9 million (€64 million) in a new facility at Rotterdam's Maasvlakte 2 to increase capacity – to 300,000-tonne/year, or four XL monopiles (XL being over 7m-diameter) a week. The monopile diameter size it can produce up to will increase to 11m. The site's quayside will be able to accommodate two installation vessels at a time and covers some 40.8ha. Meanwhile, at SIF's Roermond site, which it moved to in 1972 and increased to 13 halls with three expanded production lines in 2014, the firm is also investing $14.8 million (€12.7 million) in new production equipment.

CEO Jan Bruggenthijs marks the first day of trading for SIF.

Offshore wind technology has changed a lot since 2000. When SIF first entered the space, the maximum diameter monopile was 4m, says SIF CEO Jan Bruggenthijs, a mechanical engineer by training and CEO since 2014.

It was an easy market to move into, he says. "We were already producing the legs for the large jackets for oil and gas platforms, which at that time were also up to 4m diameter. We also produced foundation piles for jackets, which were 2.5-3m. It was familiar product," he says.

Offshore wind production really started increasing in 2010, when pile diameters were starting to move towards 6-7m, and investment has been ongoing since then. Today, diameters are around 8.5m, at least for the bottom section, with top sections around 6-7m diameter, Bruggenthijs says. At some 75m-long, they weigh around 1000-tonne each in total, compared to 40m-long pieces, in 2000, weighing 250-300-tonne a piece.

But, the firm has also focused heavily on cost efficiency, Bruggenthijs says, while maintaining pricing. As a large steel consumer, the firm, which listed on the Euronext Amsterdam in May this year, also shelters itself from steel prices, either offering fixed (with client and steel supplier) or indexed prices.

Developing its own production

processes and handling facilities has helped SIF keep busy. "We design our equipment," Bruggenthijs says. "We spend a lot of time and money in upgrading welding technologies. We weld with narrow gaps to reduce welding as much as possible, to be more efficient. We spend a lot of time on the rolling machines, and we have just bought two new ones. It is all the time looking at where we can improve the total process."

SIF has doubled the number of welding heads from two to four, to reduce welding time, and is discussing with steel producers the potential for a steel, which would be able to handle the heat from even more, to further increase efficiency. It has also had a supplier develop a special powder used to cover the weld to stop oxidation. And it's working on further developments, which we will have to wait to hear about.

An artist's impression of SIF's new site at Maasvlakte 2, Rotterdam.

The biggest change since moving into offshore wind, Bruggenthijs says, is going into continuous production – having a production line in one flow. "As all the monopiles are different this is quite a challenge. They are all unique," he says. "Monopiles are the transition between the soil, wave, wind, current and the tower and turbine they are supporting. The height changes, every monopile is unique, but they are built in a flow." Making sure they flow on time is also important to Bruggenthijs. "If you don't have the foundation you cannot build the rest of the wind turbine."

Bruggenthijs doesn't think jacket foundations will impact the business. "There's a time where jackets might be more suitable, but as it looks now, it might be only if the soil conditions need it or the water depth is over 50m and these projects are being delayed and some being replaced by monopiles. There is still huge demand to come for monopiles because it is cheaper." SIF is also looking further afield than Europe. The US, whose first offshore wind farm is due to complete soon (*OE*: July 2016), as well as Japan, are possible markets, Bruggenthijs says.

But, oil and gas work is also still on the cards. While oil and gas work is becoming an ever smaller share of production (15%, compared to about 85% in wind), as wind production increases, it's still about 30,000-tonne of annual output. SIF is set to produce some 24 piles for Norway's Johan Sverdrup development drilling platform and 20 piles and 20 leg sections for the production platform for contractor Kvaerner Verdal, in addition to jacket legs and piles it is fabricating for the riser platform. ■

Powering wind

Meg Chesshyre speaks with HSM Offshore as the company looks to the offshore wind market while the oil industry downturn continues.

During the current slowdown in offshore oil and gas activity, HSM Offshore, in Schiedam, Netherlands, is focusing on fabricating high voltage substations, says Jaco Fleumer, business development manager for the yard. This is a market which HSM first entered in 2002, providing the very first offshore Horns Rev A substation, and a second one, Horns Rev B, in 2008. Most recently, in April this year, HSM delivered the 1800-tonne Horns Rev C sub-station to Denmark's Energinet.dk. It was installed by Seaway Heavy Lifting's *StanislavYudin* and commissioning is ongoing.

"We still see a growth in the size and weight of the platforms and support structures," Fleumer says. This means that each project provides a larger work scope. The yard's latest award in this arena is for a jacket and topsides for DONG Energy's German sector, 450MW Borkum Riffgrund 2 project, comprising a topside weight of 2500-tonne, compared with 1800-tonne for Horns Rev C, and an 1800-tonne jacket. Installation will be by Heerema Marine Contractors.

This new award represents a double first for the yard; its first contract for DONG Energy and its first contract in the German sector. Borkum Riffgrund 2 is due for delivery in 1H 2018, which means that the yard still has work for the next one and half to two years. It is also good to have as a reference both because DONG Energy is currently the most active developer in the wind farm market, with access to increased resources now that its IPO has been completed, and because the German sector, along with the UK, is one of the most active wind farm markets.

HSM also has a sub-contract from Babcock Marine for the procurement and construction of a 1050-tonne jacket for the Rampion Offshore Wind Farm offshore high voltage substation, south of Brighton on the southern coast of the UK. The capacity of the wind farm is 400MW. Twelve J-tubes for incoming array cables and two J-tubes for export cables are included in the design. The jacket is already standing outside the fabrication hall nearing completion and is on target for sailaway September 2016.

Looking ahead, there is plenty of activity coming up in the Dutch sector. The Dutch Wind Energy Roadmap, drawn up as part of the country's Energy Agreement signed in 2013, sets out how offshore wind energy generation capacity is to be increased in the sector from 1000MW to 4500MW in 2023. Tendering is already under way for the Borssele I wind farm with Borssele II as an option.

Fleumer says that HSM Offshore will certainly not lose focus on the oil and gas market, but "what we currently see in the North Sea is still quite a distance away from moving into the fabrication phase." HSM's most recent EPCI delivery was the Dutch sector A18 satellite platform for Petrogas last October, comprising a 950-tonne topsides facility and a 1250-tonne jacket.

As *OE* went to press, Fleumer said he was hoping to be in a position to announce the award of another minimum facility platform. It is important for HSM, not so much for the size of the project, but for the company still to be involved in the oil and gas business, when the market recovers. In the long-term, he foresees future projects will mainly feature further minimum facility satellite platforms, with the new breed of independents working on the basis of letting EPCI to fabricators such as themselves. This is a particular area of expertise for HSM offering the most added value for the yard. ■

The Horns Rev C offshore high voltage substation.
Photo from HSM Offshore.

Fleet of foot

Damen has been quick to build a fleet ready for offshore wind operations, from fast crew suppliers to the latest SOVs. Elaine Maslin reports.

Ship builder Damen started its foray into the renewables market in 2010. The family-owned firm had already been supplying spare parts into the market, but saw a greater opportunity.

The firm built Jumbo's J-Class vessels, which, although designed as heavy transport vessels, were also outfitted with DP2 and used to install transition pieces in the North Sea. Damen's fast crew suppliers (FCS), or crew transfer vessels, as they're often referred to in the offshore wind business, Twin Axe design vessels, specially designed for the renewables, have also proved popular in the North Sea for oil and gas work, for clients including Seazip and Rederij Groen. Some 40 of its FCS 2610, for offshore wind and oil and gas work, have been sold to date.

But, one of the firm's latest projects is a vessel on another scale: the 90m-long *Bibby WaveMaster 1 DP2* service operations vessel (SOV) for offshore wind farm maintenance and support work, which is being built at Damen Shipyards Galati, Romania, with launch planned for early next year. It has a motion compensated gangway for turbine or platform access and can accommodate up to 45 maintenance personnel, management and a crew of 15 and could stay out for voyages of up to one month, traveling at up to 13 knots.

It's a whole new design, says Peter Robert, Damen's head of business development. "The SOV is the first dedicated vessel of its kind – i.e. not a converted version of another offshore type, such as a PSV," he says. "The attention that has been spent on the vessel's efficiency, seakeeping, logistical workflow and ergonomics make it very unique. The SOV combines accommodation, not just with maintenance functionality, but also installation support. Its primary market will be offshore wind, but it can also serve the oil and gas industry."

Just as it has built the FCS units in series, off spec – a Damen philosophy which has meant it is able to reduce delivery times – it also hopes to do this for SOVs. In fact, before Bibby Marine Services placed its order for the first Damen-built SOV, the firm had already decided that it would build it, Robert says.

Damen has also been supplying cable layers, including the *Nexus*, delivered to Van Oord in 2014 from Galati, and the *Maersk Connector*, delivered to Maersk Supply Service earlier this year and on long-term charter to DeepOcean. Both are based on the Damen Offshore Carrier 8500 design. The latter has a 7000-tonne cable carousel and seven-point mooring system with an ability to "ground out" to do shallow water work.

Peter Robert, Damen's Head of Business Development

Earlier this year, Damen together with fellow Dutch outfit GustoMSC, also launched the DG JACK design, a range of self-propelled and non-self-propelled jackup platforms, for use in oil and gas, and renewables for maintenance type work. "DG Jack is the result of in-depth market analysis, so we are confident that there is a market demand for it," Robert says. "This has been backed up a number of early expressions of interest from around the world. It's clear from the amount of projects beings carried out, as well as wind farms already built, that there will be a growing need for maintenance in the coming years."

Damen is also active in the wave and tidal sector. It is a partner in the BlueTec tidal development project, featured in last year's OE Region Dutch Offshore review, and its Multi Cat has also been employed in this sector, by Scotmarine in the UK. ▪

The *Bibby Wavemaster*.
Images from Damen.

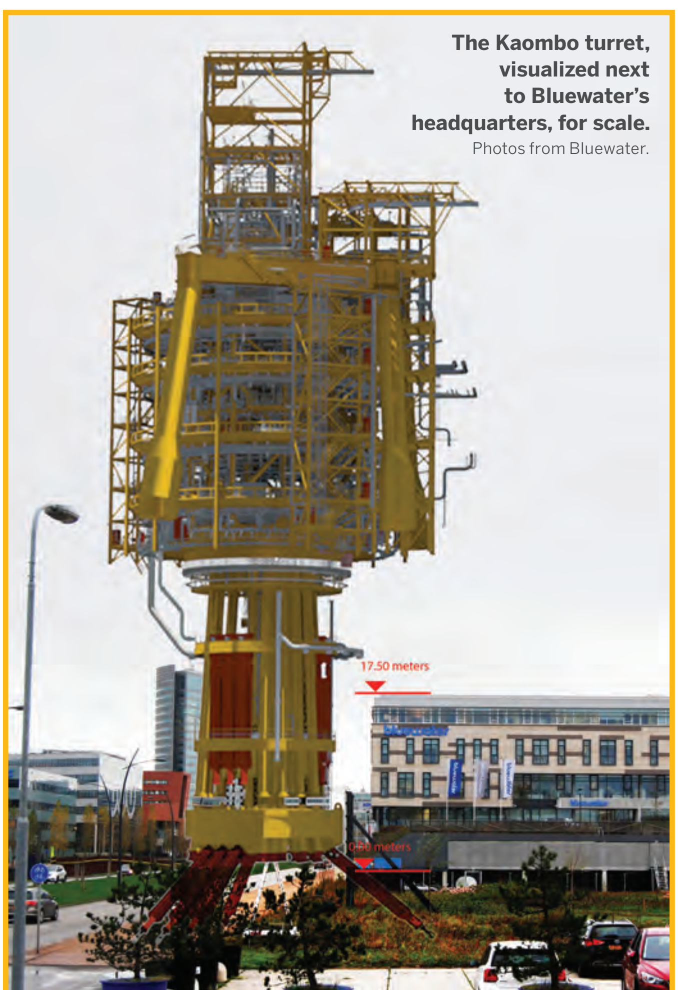
Connecting Kaombo

FPSOs and the single point mooring systems that connect them to the reserves they produce are Bluewater's business. Elaine Maslin speaks to senior project manager Jeroen de Werd about turret design and the Kaombo project.

This year, Dutch floating production specialist Bluewater is past mid-way through building its two, largest ever turret systems, the 85m-high internal turret systems for Total's twin floating production system Kaombo development offshore Angola, for contractor Saipem. With 17m-diameter bearings, they are among the largest turrets in the world.

But, even as the firm, which has been designing single point mooring systems since 1978, breaks its own records, Jeroen de Werd, Bluewater senior project manager on Kaombo, says there's no standing still. Even bigger systems are being designed and challenges such as arctic and LNG developments receive the necessary attention.

Turret systems are a type of single point mooring system. They can be internal or external, and fixed or disconnectable, and enable oil to flow up from subsea wells onto a vessel. The turret is usually fixed, through a mooring system, while the rolling, pitching and heaving vessel is able to swivel or weathervane around it. Designs are influenced by water depth and the marine environment, which drive the mooring spread and loads the turret has to accommodate, as well as the production system – how many riser slots are required, type of fluids, injection requirements, etc. – and ever more stringent regulations and operator requirements.



The Kaombo turret, visualized next to Bluewater's headquarters, for scale.
Photos from Bluewater.

The heart of the system is the swivel stack, which enables the transfer of liquids and gases from the risers onto the vessel, via a circular process manifold fixed to the turret and an access structure fixed to the vessel, as well as providing a conduit for power, controls, hydraulics, injection fluids, etc.

Turret size has been steadily growing as fields have been developed in ever deeper, harsher and more remote locations, with greater production capability requirements. Greater controls systems, more remotely controlled switch boards, submerged pumps and greater functionality have also been added, including cross-manifolds, pigging systems, condition monitoring capability and the ability to handle high-pressure high-temperature production. In summary: more robust, reliable and safe turret systems, which are at the same time easier (and therefore most cost effective) to operate and maintain despite their growing functionality.

Kaombo fits that trend. Total says Kaombo is its largest development today, in deeper waters than Total has been in offshore Angola before, at up to 1950m. The development's two FPSOs, Kaombo Norte and Kaombo Sul, will produce oil from a cluster of scattered reservoirs covering some 800sq km – or eight times the area of Paris. Covering such an area will mean laying Angola's largest subsea network for a single project – with more than 300 km of pipelines, according to Total. Rather than a newbuild vessel, Total and Saipem are now converting two crude carriers for the project, at Sembawang Shipyard in Singapore, with 180,000 b/d oil production capacity, 2.9 MMcm/d gas export and 200,000 b/d water injection capacity.

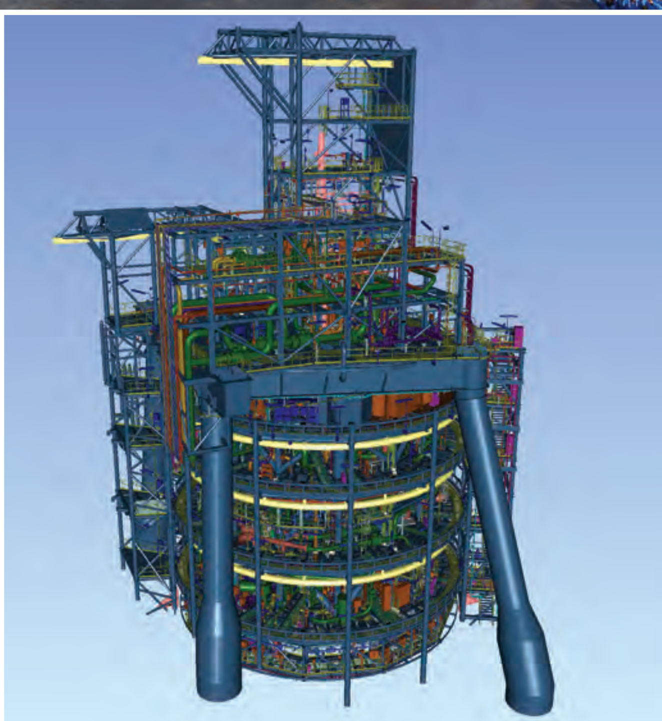
Each turret has to be able to accommodate a nine-point deepwater mooring spread and 18 riser slots, resulting in the 8000-ton a piece systems being built, with 25m-high swivel stacks. Each contains some 10km of piping and 80km of cabling, highlighting some of the complexity involved in these structures. The main bearing, a roller bearing, is 17m in diameter, equivalent to nearly the length of two double decker buses. In comparison, the first turret systems were only a few meters in diameter and weighed just a few hundred tonnes.

"The Kaombo turrets will be among the largest and most complex turret systems ever designed and built to date," de Werd says. "Each of them will weigh 8000-tonne. It is a massive development in size and in weight as direct consequences of environmental loads, motions, and prescribed requirements."

The turrets are being built in three locations. The lower turret which includes a pre-fitted main bearing is being built in Abu Dhabi. The upper turret is being built at the Sembawang Shipyard in Singapore, where the vessels are also being converted. The swivel stack and main bearing are being manufactured in Germany.

Typically, projects like this take about 3-4 years, de Werd says. Design, procurement, and construction take up to 2.5 years, then installation and integration, onshore commissioning and transit to field, hook up and offshore commissioning the balance of the time.

The lower turret, ready for sailway to Singapore.



A 3D model of the turntable and access structure.

The Kaombo project started in April 2014 and first steel was cut in early 2015. The first turret was being integrated in May this year, with integration of the second due later in the summer.

The project has strong Dutch content, with contractors and suppliers including Frames, Drie-D, IHC, Trustlube, Gerritsen, and Trelleborg. Others like Heerema Marine Contractors (HMC) are also involved in the Kaombo development project.

But, while there's a lot of focus on Kaombo, Bluewater continues to work on other awarded projects, such as Rosebank. The design for the Rosebank FPSO, which would have to contend with huge wave regimes in the rough, deep areas at west of Shetlands (UK), is even larger – at some 30m wave height in 1220m water depth.

The firm is also continuing to develop turret and swivel stack technology for future needs:. "You need to innovate, be smarter, faster, cheaper, deliver sooner and be able to cope with challenging field characteristics like sour and HPHT services, novel requirements and even harsher environments, more remote locations, and 25+ years design lives," de Werd says. "For example, our current turret designs usually accommodates pressure for water injection and gas export up to 350 bar. Nowadays, exceeding 500 bar is more commonly asked and we are developing 700 to about 1000 bar pressures and temperatures exceeding 130° C. There is quite some development in that respect."

There is also work ongoing on disconnectable systems with and without DP, for early well tests, where operators might want early cash from their reserves but not investing in a full system for decades. Bluewater is looking at arctic, LNG and heavy oil solutions, as well as systems for marginal or stranded areas.

"Apart from higher safety standards, cost reductions and challenging schedules, those are the greatest opportunities," he says. "The challenge is to make sure we continue to be able to understand the demands of our clients and locations where they need solutions." But, while a lot of focus is on technology and system design, having a proper execution model is also crucial, de Werd highlights, and they must go hand in hand on complex systems like this to make sure the projects are a success.

Bluewater also owns and operates a fleet of floating production vessels and floating storage and offloading units, and it is leading a tidal energy project, featured in last year's Dutch Offshore review. ■

The Culzean wellhead jacket, under construction.

Keeping busy

Meg Chesshyre speaks with Heerema Fabrication Group's CEO Koos-Jan van Brouwershaven about the firm's activity in both the oil and gas and renewable markets.

The Montrose BLP sailaway in April. Photos from HFG.

Heerema Fabrication Group (HFG) is happy to report that all three of its Dutch yards have a reasonable work load, despite the fact that the overall level of business is much lower than before the oil price collapse. HFG's smaller specialist facility at Opole in Poland is also fully occupied supporting the projects at the other three yards.

At the Vlissingen yard work is underway on a procurement and construction contract for two jackets for the central processing facilities (CPF) and the utility and living quarter (ULQ) platforms for Maersk Oil North Sea UK's high-pressure, high-temperature Culzean field. Sailaway is planned for June 2017. The CPF jacket will weigh almost 8000-tonne and the ULQ jacket 6900-tonne. The fabrication of the cluster piles is split, six x 500-tonne each within Heerema Hartlepool, in England, to add UK content, and two x 600-tonne each at Zwijndrecht along with 1500-tonne scope for legs and risers.

HFG completed the 6600-tonne Culzean wellhead jacket and 400-tonne access deck (WAD) for Maersk Oil this April. Heerema Vlissingen constructed the jacket, while the WAD with the access ways, was built by Heerema Hartlepool. The platform was then installed by sister company Heerema Marine Contractors' (HMC) semisubmersible crane vessel *Thialf*. Brouwershaven explains that the construction of the wellhead jacket was quite challenging due to the twisted base design that allows better access for the drilling rig.

The Vlissingen yard has secured a significant contract in the renewables sector from Petrofac for the procurement and construction of the 5300-tonne jacket and 600-tonne piles for the HVDC substation for the German sector BorWin3 project. Sailaway is scheduled for March 2018. HMC has the transport and installation contract. Engineering will be carried out by Petrofac. HFG has previously built the DolWin Alpha and HelWin Beta platforms.

Earlier, Petrofac awarded Heerema Hartlepool an approved for fabrication contract for fabricating the substation platform for the Galloper wind farm, comprising a 1900-tonne topside and a 1700-tonne jacket. Project engineering and procurement are being undertaken by Petrofac as part of the GE Petrofac consortium. Sailaway of the platform is scheduled early in 2017. Galloper is an extension to the Greater Gabbard wind farm, but is being developed as an entirely separate entity. In 2008, the Greater Gabbard topsides transformer platform was Heerema Hartlepool's first engineering, procurement and construction (EPC) project in the offshore wind energy sector.

The 10,500-tonne Montrose bridge linked platform topside for Talisman Sinopec Energy UK sailed out from Heerema Zwijndrecht in April. It was installed in the field by the *Thialf* in May.

In April HFG completed Oranje-Nassau Energie's unmanned sustainable satellite platform P11 with a 400-tonne topside and a 600-tonne jacket.

Heerema Zwijndrecht is now progressing with the EPC scope for Statoil's Oseberg Vestflanken 2, 900-tonne unmanned wellhead platform due for delivery in May 2017. The first cut of steel took place in June 2016. The jacket will weigh about 4000-tonne. It will be equipped with piles rather than suction buckets. Brouwershaven says this is a novel solution for the Norwegian sector, although quite common elsewhere. "We call it 'a dry tree on a stick. It's lean and mean, and we believe that it is the way forward to save costs," he says.

Brouwershaven adds that while the yards are less busy, HFG has embarked on an internal process, first initiated a couple of years ago, called Back2Basics, looking at how "to become the best cost provider in the broadest sense of the word, not only being the cheapest, but also providing the best product, quality-wise, time-wise and price-wise." The group's dedicated innovation center, which opened in Zwijndrecht last November, is pursuing a research and development program, including the development of a welding robot. The group is also working on a series of safety videos covering hand and eye injuries, trip and falls, falling objects and hearing protection. ■

Electrifying

VBMS isn't an old company, but it's making electric cable waves in both the offshore renewables business as well as at its new parent company Boskalis, reports Elaine Maslin.

Founded in 2007, as a subsidiary of VolkerWessels, Visser & Smit Marine Contracting (VSMC) was get to work. Its first export cable installation was in Belgian waters for the Thornton Bank Phase 1 wind farm and the firm has had involvement in about every wind farm since then, says managing director Arno van Poppel. Indeed, this year, the firm marked its 1000th inter-array cable lay and it is set to be the first to install new 66kV cables on the Blyth offshore wind farm.

In 2013, Dutch marine contractor Boskalis became a 50% shareholder of VSMC, creating VBMS. The move meant VBMS was able to offer a full package, with VolkerWessels providing onshore cabling, horizontal directional drilling and terminations expertise, and a track record in subsea cabling, combined with Boskalis' marine contracting and services experience. But then on 1 July this year, VBMS became part of Boskalis, after Boskalis agreed to acquire the remaining 50% of VBMS from VolkerWessels. The deal also included the acquisition of VolkerWessels companies Stemat and VSI, including all assets used in Offshore Wind Force, a joint venture between Boskalis and VolkerWessels, which is currently working on the foundations of the Wikinger and Veja Mate wind farms, offshore Germany.

"We are able to offer the full EPIC services for offshore power systems making a connection to the onshore and offshore grid," van Poppel says. "At the moment, we are the only party in the market with four cable laying spreads working simultaneously." This is using Boskalis' *Ndeavor* and *Ndurance* vessels and former VolkerWessels' assets *Stemat Spirit* and *Stemat 82* vessels. And, the firm is capable of more. "When we installed the London Array [wind farm] cables, at that time the biggest offshore wind farm in the world, we had six spreads working simultaneously in the water," he says.

Installing the first 66kV cable, a technology which has been in development for some years, to meet the increasing capacity of today's 8MW+ wind turbines, will be a badge of honor for VBMS. Some 14km of the cable, produced by Nexans, will be laid at the Blyth offshore wind farm for EDF Energy Renewables in 2017.

Van Poppel attributes the success to a number of factors. "We do the whole installation first in virtual reality," he says. "We make all the calculations in every detail before we start sailing. It is about preparation in every detail, improving efficiencies, having the right people on board and being prepared. Anybody can buy or charter a vessel. But a subsea power cable is a delicate product and it needs to be treated carefully. The difference is made by the people installing it, the people on the vessel itself and the crew who have the experience and who knows what you can and cannot do. Making the right judgement and getting it right, the very first time, is making the real difference."


Arno van Poppel

But, like others in the industry, the firm is keen to help reduce costs, to make sure the business is viable. "In offshore wind, there is some uncertainty about the future. The main reason is that the total supply chain has the clear objective and responsibility to further reduce the levelized cost of energy," he says. "So far, costs have mainly been reduced because larger turbines have been developed, lowering the cost of a MW/hour. But, we are getting to the edge of that development. To make further progress, I think we have to find different ways of cooperating within the supply chain. It is about transparency, innovation and reducing or managing interfaces more efficiently and reducing risks."

VBMS is currently working on the Dudgeon wind farm, off the UK coast, the Normandie 1 Interconnector between the French coast and Jersey and it has just finished the cable shorelanding for the Nordergründe offshore wind farm and inter-array cable installation and burial for the Sandbank offshore wind farm "It is a good year for VBMS," van Poppel says. ■


The *Ndurance* at work.
Photos from VBMS.

Joined up separation

Dutch firms Frames and Royal IHC are taking a step into the deep, quite literally, as well as figuratively. Elaine Maslin sets out the detail.

Frames, which is used to developing specialist process equipment for topsides and onshore, is working with Royal IHC – with its expertise in the subsea business – to develop a subsea separation package. The two firms are also planning to look at produced water treatment equipment for water reinjection. Both are key challenges for the subsea industry as operators look to process more production on the seabed.

But, the firms are not starting from scratch. The work will build on the SwirlSep, a compact controllable inline separator Frames has been developing since it acquired the exclusive license of Twister SwirlSep – a separation technology able to handle changes in flow rate – by combining SwirlValve, a pressure actuated valve technology, and an inline separator.

SwilSep was developed as a compact solution for debottlenecking brownfield facilities where space is at a premium. But, given changing flow regimes on brownfields, the firm decided the technology needed to do more than handle a limited flow regime.

3D model of the SwirlSep with explanation.
Photos from Frames.

One of the problems with conventional technologies, says Raoul Liew, R&D engineering, SwirlSep, is that they're not flexible enough to handle changes in flow regime, flow rates as well as oil-water ratios, etc., which often occurs on brownfield sites but also over the long-term."Most people know how a cyclone works. You inject the mixture and it forms a swirling flow," he says. "Centrifugal forces are generated and the heavy material swirls to the outside and the lighter material to the inside. That works well if you design the system in such a way it can handle a certain flow range."

Raoul Liew, Frames

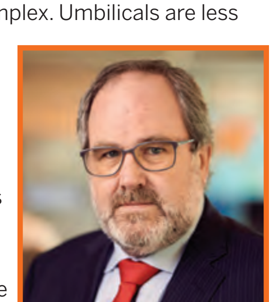
The drawback is that the centrifugal force is generated by the flow, which means if your flow rate drops, you limit the range, or turndown, the separator is able to operate at. You need something that can overcome this, something that can handle turn down and changing gas/liquid ratios, etc.," he says. "We started looking in to SwirlSep and a two phase separator idea."

While SwirlSep also uses centrifugal forces, these are maintained by using the SwirlValve, developed by Dutch firm Twister. SwirlValve is ΔP controlled with tangential orientated holes around the SwirlValve's "swirl trim cage," maintaining the swirl velocity, reducing pressure drop and so maintaining the centrifugal forces.

This makes SwirlSep unique because it is controllable, Liew says. "This controllability means we can handle fluctuating flow rates to a higher extent – demisting, bulk separation, etc. – and we think that is unique, especially for a small device." With a viable compact separator on its hands, the step towards offering this technology as a subsea solution was obvious.

Subsea processing is seen as attractive because moving technologies to the seafloor can debottleneck topsides facilities as well as reduce other requirements in the field and increase efficiency – and ultimately recovery rates. "Getting liquids to surface [from subsea wells] comes at a cost," Liew says. "Because of the water depth, you need to get over the high head to keep producing. If you can lower your equipment to the sea floor, you can separate the flow there and then boost it to the surface. This means you don't need complex multiphase pumps. Power consumption is much lower. The system is less complex. Umbilicals are less complex."

Providing a compact system also has big benefits. "Systems on the market are a development of conventional systems, which are voluminous and taking them subsea makes them very expensive," says Henk Cornegé, senior business development manager, IHC. "The equipment we are developing will be a fraction of the size and weight of current systems."



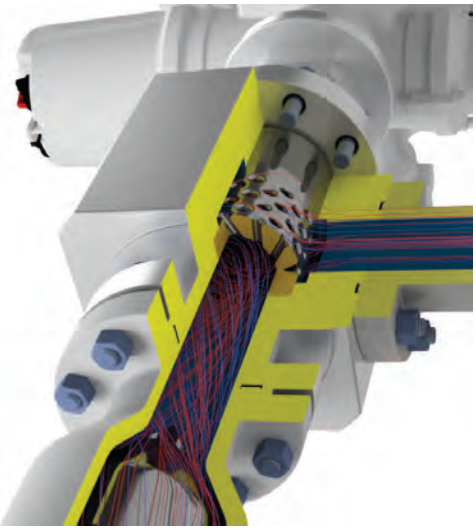
Henk Cornegé, Royal IHC

To date, SwirlSep has been designed for a number of applications and depending on the application Frames is at different technology readiness levels (TRLs). The most advanced was a liquids and solids removal system used in 2014 to help clean out gas wells on a NAM-operated field in the Netherlands, taking it to TRL 7-8.

There will be field trials beginning next year on bulk separation together with a Middle East customer, taking a liquid gas separation version to TRL-7. Further experiments are also starting focusing on the behavior of the separator when in liquid degassing mode and the company plans to continue lab work on bulk separation and demisting, to further validate models, Liew says.

The next step will be developing the technologies to withstand subsea conditions. "One of the challenges we see over the life span of the components is the maintenance intervals," Cornegé says. "Onshore you can access them quite easily. Replacing components subsea is not so easy. We are going to have to guarantee the life span and access by ROV (remotely operated vehicle), which means looking at choice of materials, wear patterns, etc."

Another key challenge is designing a control system to control the outlet flow rates as well as the pressure drop over the system, similar to what is done on a hydrocyclone. However, as the equipment is compact, it needs a fast control system with fast sensing. It will also require flow meters, which means you are effectively creating a multiphase flow meter, Liew says, which can also be used as a test separator, but also using data from the well itself.



3D model of the SwirlSep with flow scheme.

But, before Frames and IHC develop a full subsea system, they will be looking to the operator community for a partner to make sure they're developing what the industry needs, as well as to eventually take it forward to trials.

They also have their sights set on subsea produced water treatment, which would mean water could be reinjected instead of having to be lifted to the surface, says Jeroen Bergman, product manager, Produced Water Treatment, Frames. The challenge will be what to do with any sand that comes with that water, as reinjecting sand can damage the reservoir. The market might not be quite ready yet for such technologies, but it will come. "In the future we will see heavy oil fields, which contain sand being produced," Bergman says. "So, we do see a serious challenge to deal with sand content in water," especially when it comes to limited topsides space.

Jeroen Bergman, Frames

There's a lot of work to be done, and it could be 2-3 years, before the technology is ready, but the two firms think they have the right partnership to make it happen. ▪

Going against the gloom

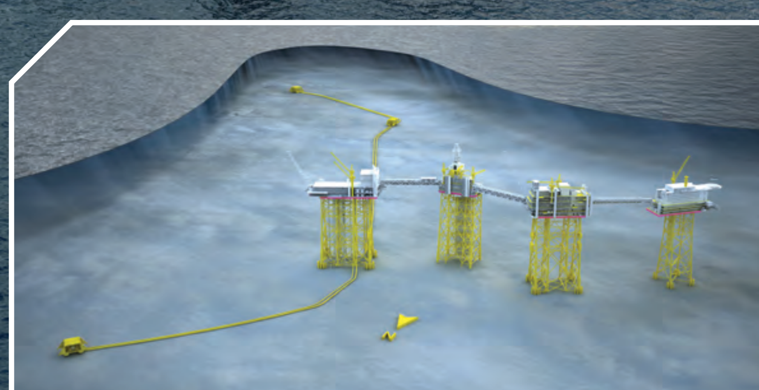
John Bradbury takes a look at activity in the North Sea – across Norway and the UK.

By the middle of 2016 it was evident that despite the downturn the North Sea's biggest project was steaming ahead.

But industry gloom isn't far away either: a report by PwC, which canvassed 37 oil and gas leaders across the North Sea Basin – in Norway, the UK, and Holland – recently suggested a two-year window of opportunity remains before much of the remaining North Sea potential could be lost through decommissioning of aging infrastructure.

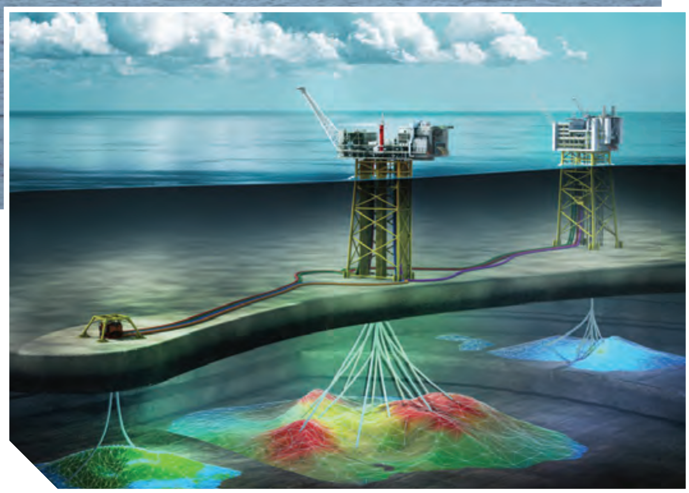
While significant levels of optimism persist about the future of the basin, the PwC report, "A Sea Change," found executives calling for closer cooperation among operators, contractors and governments, and for changes in leadership. "Our respondents recognized that a change of guard at the top is essential if the industry is to successfully disrupt its 'we've always done it this way' mentality and become a force for innovation and re-invention while demonstrating entrepreneurial and forward-thinking leadership," said the PwC report.

The study calls for the creation of a "super joint-venture vehicle," which is seen as key to consolidating smaller and fragmented assets under one operator, which almost sounds like a call for a state oil company. PwC found evidence of an industry "…keen for the regulator to lead from the front," and



Johan Sverdrup – an artist's impression. Image from Statoil.

The Ivar Aasen jacket has already been installed. Image from Det norske.



The Ivar Aasen project, an artist's impression. Image from Det norske.

"There is an expectation from industry that the regulator not only sets a holistic framework for the basin, but is more assertive to change behaviors."

Sverdrup advancing

GE Oil & Gas was the latest major contractor to collect a deal to deliver services to Norway's Johan Sverdrup megaproject. Surface wellheads, xmas trees and related services will be supplied by GE. Although the contract value was undisclosed – but is likely to be measured in millions of dollars – GE said the deal was a multi-year contract for supplying hardware for "multiple wells." Reports have indicated 35 production and injection wells are required for phase one at Sverdrup and the GE supply scope is for 23; FMC Technologies is supplying 13 trees and wellheads.

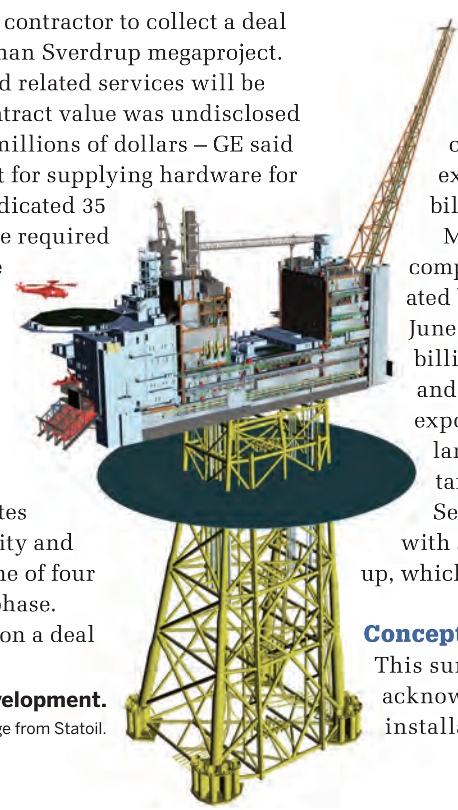
Separately, construction has started on the four bridge-linked platforms for the first phase of the 1.7- 3 billion bbl project. At Kvaerner Stord, Norway, steel plates were cut for the 19,000-tonne utility and living quarters (ULQ) topsides, one of four installations for Sverdrup's first phase.

Kvaerner and KBR combined won a deal for complete delivery of the ULQ in June 2015. Meanwhile, at Kvaerner Verdal, three of the four steel platform jackets are being constructed for the remaining three riser, drilling and process platforms. Spain's Dragados Offshore is constructing the final jacket for the ULQ.

Apply Leirvik in Norway is building the accommodation module for the ULQ. Topsides for the riser and process platforms are being built by Samsung Heavy Industries. Norwegian firm Aibel is constructing topsides for the Sverdrup drilling platform. Development drilling for the first 35 phase one wells started in March.

Recently, Statoil indicated a reduction in capex for Sverdrup phase one, from NOK 123.2 billion (US$14.4 billion) at PDO submission, to NOK 108.5 billion ($12.7 billion) at present.

Partner Lundin Petroleum reported in May that a de-bottlenecking study suggested a potential increase in processing capacity from 315,000-380,000 b/d to 440,000 b/d of oil for phase one. Sverdrup phase one is due onstream at the end of 2019. This year concept selection for phase two at Sverdrup is due – a study for which is underway by Norway's Aker Solutions.



The Gina Krog development.
Image from Statoil.

Imminent start-ups

Earlier this year saw first oil from the Goliat field, the first surface development in the Barents Sea using a Sevan Marine round-hulled FPSO (floating production, storage and offloading) tapping an estimated 174 MMbbl of oil and the first project to be operated by Eni Norge, offshore Norway.

The next start up is likely to be Ivar Aasen, another NOK 18.025 billion ($2.1 billion) fixed platform project offshore Norway, which will also tap the West Cable discovery and the Hanz accumulation in a second phase. It is due onstream in Q4 2016, and is operated by Det Norske.

Asta Hansteen, using an eight-slot, deepwater spar, was approved for development in 2013, and is due onstream late 2018, costing an estimated NOK 3 billion ($350 million).

Next will be the 225 MMboe Gina Krog development, using a fixed platform and an FSO (floating storage and offloading). It is due to come onstream in Q1 2017 with oil offloading and gas export via Sleipner A, at cost of NOK 31 billion ($3.6 billion)

Martin Linge will follow in 2018. It is a structurally complex, high-pressure, high-temperature field operated by Total, which gained development approval in June 2012, is currently costed at NOK 34.8 billion ($4 billion), and will be developed with a fixed platform and an FSO, with power from shore. Rich gas will be exported via pipeline into the UK Frigg system and landed at St Fergus, while oil and condensate will be tanker-offloaded. Production well drilling started in September 2014, using the Maersk Intrepid jackup, with six wells due to be ready before production start-up, which is scheduled for 2018.

Concepts

This summer saw the Norwegian Petroleum Directorate acknowledge a new type of platform – an unmanned installation - could be permitted offshore Norway. This new concept for Norway, but widely used in the Dutch and UK sectors, will be deployed on the Oseberg Vestflanken 2 project for which a plan for development and operation was approved by the Ministry of Petroleum and Energy in June (Read more, page 36). The installation - 9km from the main Oseberg field center – is due onstream in 2018 operated by Statoil and will tap 110 MMboe of reserves – 62 MMbbl is oil, and 7.8 Bcm is gas.

Norway's Barents Sea Johan Castberg field encompassing the earlier Havis and Drivis discoveries and 110km beyond the Snohvit field off northern Norway, is still subject to conceptual studies, including an FPSO. Reserves, according to the Norwegian Petroleum Directorate, are 85.9 MMcm (540 MMbbl) but an onstream date – originally touted for 2018 – is still unknown since it has been delayed several times.

For the Johan Castberg project, Statoil's current capex forecast is down 50-60% from NOK 100 billion ($11.6 billion) back in 2013 to NOK 50-60 billion ($5.8-7 billion) at present reflecting cuts in industry costs as the oil price has tumbled in the last two years (Read more, page 16).

UK activity

While two new significant projects are due onstream – BP's £3 billion ($4 billion) Quad 204 redevelopment, West of Shetland, using the new build *Glen Lyon* FPSO (due onstream this year) and its Clair Ridge development (expected online at the end of 2017) – activity in the UK is, more broadly, at a much lower level.

Chevron recently signaled that it has abandoned a plan to use a new bridge-linked platform for an EOR (enhanced oil recovery) project at its Captain heavy oil field. Instead Chevron, which had earlier issued tenders to four platform bidders, revealed that it has instead opted for a lower cost concept, based on brownfield modifications to the existing Captain A facility.

But, Maersk is progressing its $4.5 billion, three-platform Culzean development, for which first steel was cut earlier this year at Sembcorp Marine Offshore Platforms, formerly known as SMOE, in Singapore.

Ithaca Energy is progressing its Greater Stella area development to tap the Stella and Harrier fields with a converted floating production unit, the *FPF1*, which was due to leave the

Maersk Drilling's Maersk Inteprid jackup has been drilling on Total's Martin Linge project. Photo from Maersk Drilling.

Remontowa yard in Gdansk, Poland, in July and transit to the UK North Sea field.

Two other UK projects, the Kraken heavy oil development by EnQuest, and the Catcher project by Premier Oil, both using FPSOs also, are due onstream in 2017.

EnQuest shaved $425 million off the original $3.2 billion Kraken cost earlier this year. The converted integrated turret FPSO, which will be leased from and operated by Malaysia's Bumi Armada to EnQuest, departed dry dock in December last year and is on course for departure from Singapore in 2016. Bumi is converting a recently built ice-class tanker for the conversion. It will use an NOV buoy turret mooring with 16 risers and Framo swivel stack. Four production wells are due to be available at first oil.

Premier Oil has also been shaving costs off its project, Catcher. The project, involving a new-build FPSO on contract from BW Offshore and with Aibel fabricating the topsides, is now forecast to cost $1.35 billion to first oil, after a 15% reduction in costs. Catcher will be a 22 subsea well project (14 producers and eight water injectors) expected to produce 96 MMboe over its lifetime. OE

Det norske's *Alvheim* FPSO, soon to be part of Aker BP.
Photo from Det norske.

Northwest Europe

Europe in Crisis?

The industry will emerge from its current crisis, but the next chapter in the oil and gas industry may look very different. Hannon Westwood's Andrew Vinall gives his view.

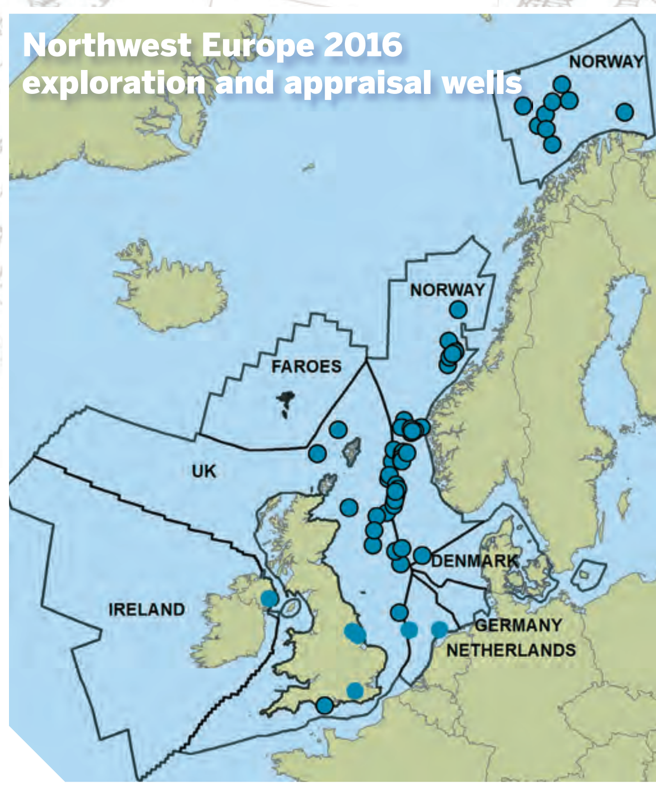
It's a complex picture for Northwest Europe due to falling commodity prices, high development and operating costs, lack of commercial exploration success, funding shortfalls, stalled commercial activity, pending flights of capital to onshore and renewables with private equity poised to invest. Making matter worse the Brexit vote in late June sent markets into turmoil, and then, there's the threat of strike in the UK and Norway for higher offshore wages.

Over the past year activity that was not already commissioned has largely stalled, while projects that were planned, or at the point of sanction, have either been deferred or sent back to the drawing board for redesign and cost reduction.

Despite Brent's recent recovery from its January low, there is still a nervousness in the sector over oil prices given continuing global oversupply concerns. In the medium term, Brent may stabilize around US$60, which approximates to the average cost of production on the UK Continental Shelf and is also the point at which shale oil in the US begins to be seen as viable. This could lead to the creation of a self-regulating pricing system, but one effect could be that there will be a number of high opex fields in Northwest Europe that could be considered for early cessation of production. Until we have a period of price stability and sustained reduction in costs to give headroom for profits, we will not see reinvestment by oil and gas companies in exploration.

Exploration activity levels are a good check of a sector's health. This is nowhere better reflected than in the UK over the past few years and more recently in Norway, the two areas where activity levels are higher than the rest of Northwest Europe.

Until the last couple of years, the issues facing the UK have been different from those in Norway, where the direct government rebate for exploration has ensured that activity levels are maintained even as success rates have fallen. But, even Norway is not immune from the downturn and this is reflected by recent figures. The hope is that reduced activity levels will lead to smarter exploration and a relative increase in success and while that may be true, there could also be a short-term hangover. Some higher risk wells will be drilled due to outstanding commitments that were made in more optimistic times and we will have to wait a while longer for the better prospects to come through.



So where do we stand? Since 2012, exploration and appraisal activity in the UK has been in continuous decline, although for the past three years it has been appraisal drilling that has shown the greatest decline, while exploration drilling remains at a relatively steady, if historically low, level.

Compare this with Norway on the other hand and we can see that, apart from 2012, when appraisal drilling pushed the activity in the UK above that of Norway, Norway has been consistently outperforming the UK in terms of overall drilling activity.

The comparison of the number of exploration and appraisal wells between the UK and Norway is notable. The UK has consistently shown a greater weighting towards appraisal than Norway. This can be attributed to several factors: the maturity of the UK; the complex, commercial uncertainty of a greater number of undeveloped discoveries than in Norway; and the desire to explore for new material reserves in Norway against a backdrop of effective government subsidy for exploration drilling, something that is not, and probably will never be, available again in the UK, other than for those few companies that can offset exploration expenditure against tax.

As a consequence of government incentives, Norway has continued to explore at a relatively high level through the start of the downturn and throughout 2015; however, fiscal prudency resulting from the key factors of high sector costs, lower profitability and restrictions on access to new capital has led to lower global exploration budgets and a consequent decrease in exploration drilling. Poor recent exploration performance in Norway is also considered to be a factor; the UK discovered more resources with significantly fewer wells in 2015, with all but one discovery being considered potentially commercial.

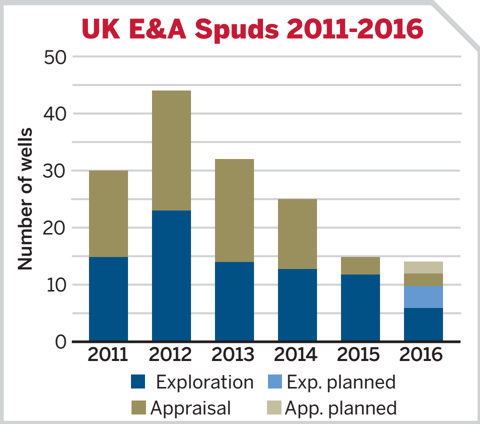
In 2016, it appears that Norway will be harder hit than the UK and although activity in the UK is expected to reach an all-time low with only 10 exploration and four appraisal wells likely to be drilled, this really represents only a marginal decrease from 2015 levels.

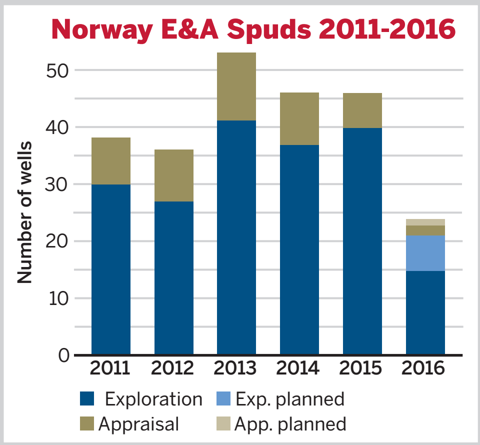
At the start of the year it was thought that the number of wells in Norway would be severely curtailed and we predicted around 29 exploration wells would be drilled over the course of 2016. Drilling over the first six months of the year showed activity levels were way below those of 2012 and consequently the predictions have been downgraded accordingly, with an expectation that now only 24 wells will be drilled, 21 of which will be exploration. Worryingly for Norway, this represents a near 50% decrease on 2015. This figure does not include Lundin's re-entry of Neiden in the Barents Sea, which was commenced and suspended in 2015.

The UK and Norway have been the most active European provinces for a long time, with the Netherlands the third most active.

In 2015 there were 12 wells drilled in the Netherlands; nine exploration and three appraisal, though 2016 levels are already significantly below this with only two wells, one exploration, one appraisal (both offshore) drilled in the first six months. Denmark remains at very low levels with only two exploration wells drilled in 2015 and none drilled in the first six months of 2016. We expect one or two wells to be drilled in each of the Netherlands and Denmark in 2H 2016, and no wells are anticipated in the Northwest Europe provinces of Faroes, France, offshore Germany, Greenland, Iceland or Ireland.

Merger and acquisitions activity was expected to pick up in 2016 following a lull in 2015, while stresses in the system were absorbed and the industry waited for distressed companies to be revealed. While there were a large number of assets, from production through to exploration on the market





UK	2011	2012	2013	2014	2015	2016
Exploration	15	23	14	13	12	6
Exp. Planned	0	0	0	0	0	4
Appraisal	15	21	18	12	3	2
App. Planned	0	0	0	0	0	2

Norway	2011	2012	2013	2014	2015	2016
Exploration	30	27	41	37	40	15
Exp. Planned	0	0	0	0	0	6
Appraisal	8	9	12	9	6	2
App. Planned	0	0	0	0	0	1

Figures as of end June 2016. Data from Hannon Westwood.

in Northwest Europe in 2015 the differential expectations of value between buyer and seller were such that many assets in which there was acquisition interest could not secure sufficient sale prices to meet hold values and therefore sales did not proceed and assets were removed from the market.

Notably, there was Shell's acquisition of BG Group that dominated global M&A, which has precipitated a $30 billion divestment program from the combined portfolio, much of which is expected to come from European assets. The acquisition by private equity group Sequa, via its Norwegian subsidiary Tellus, of a number of production and development assets from Wintershall and Total collapsed in the late stages most likely due to funding issues resulting from the fall in oil price. Company collapses in the NW Europe arena related to debt were First Oil (UK), Atlantic Petroleum (Norway, Ireland UK), Noreco (Norway, UK), PA Resources (UK, Denmark), Iona (UK). In each case, these collapses brought about divestments of various types with all but First Oil restructuring in some way that will allow the companies to continue in some form going forwards, though Atlantic Petroleum and PA Resources are no longer active in NW Europe.

The industry is waiting for prices to stabilize at or above $60/bbl, at which point investment for all but the asset poor private equity buyers, who are continuing to look for bargains in the current market, will start investing again, though it is expected that the multinationals will continue to concentrate their medium-term investment on areas that offer the highest margins and these might not include Europe. As with previous deep downturns the industry emerges fresher, leaner and potentially stronger with some changing of the old guard. There is a feeling that this time is different with long-term oversupply, the rehabilitation of Iran and the potential that US shale will act as the new swing producer and that these will moderate the future landscape so that a return to $100/bbl oil will be a long way off. But, emerge it will and a new chapter in the oil and gas industry will begin. The question is, how much of it will be in Europe? **OE**

__Andrew Vinall__ is technical director at Hannon Westwood. He is a senior geoscientist with expertise in geological and geophysical interpretation. Vinall has extensive career experience spanning production, development, exploration and commercial aspects of the UKCS. He co-founded Hi-Grade in 2003, which was purchased by Hannon Westwood in 2005.

Northwest Europe

Leaving no rock unturned

Elaine Maslin examines new UK government funded seismic shoots and data reprocessing, all free to the industry, which are among initiatives aimed at boosting UK Continental Shelf exploration.

While exploration has been dwelling at historic lows on the UK Continental Shelf (UKCS), a scheme to open up underexplored areas of the basin could yet turn the trend around.

The UK's still relatively new Oil and Gas Authority (OGA) was given government funding to shoot seismic over the Mid North Sea High, in the central North Sea, and the north Rockall Trough, west of Scotland, last year, supported by legacy data reprocessing. Both are being used to decide what will be offered in the 29th licensing round, which was due to open early August. Further, the OGA is eyeing yet more new seismic acquisition in areas of western Britain and the East Shetland Platform this year.

Gunther Newcombe, director of exploration and production at the OGA, and a geologist by education, thinks there's a lot that has been overlooked in the basin. "People call the area [North Sea] mature, even super mature, which is true for some areas. But, some mature areas, like the southern North Sea, still have potential. Carboniferous tight gas has a lot of potential, for example."

To shine a light on these underexplored areas, the OGA has spent £20 million (US$26 million) of government funding on new 2D seismic data.

The new seismic was shot by WesternGeco, covering 200,000sq km of the UK Continental Shelf. What's unique is that it, and the 20,000km of legacy data, is being made freely available to the industry – in processed and unprocessed form. Furthermore, some of the legacy data are lines that can no longer be shot again, due to fishing gear now in the area. Some of the 1980s seismic was also shot with dynamite, which offers a good quality clean source but is no longer used.

The shoot used long offset broadband seismic for lower frequency data, something that has been missing in the past, OGA says. Gravity and magnetic data were acquired at the same time. To get the data to the market as fast as possible, onboard processing was carried out from September 2015 to March 2016. By 24 May, some 6000 data packages had been downloaded.

Rockall Trough

The Rockall Trough and Mid North Sea High were chosen because they're underexplored. Fiona Legate, senior analyst, UK Upstream Oil and Gas, Wood Mackenzie, says only Austria's OMV, an integrated oil and gas firm, and independent minnow Parkmead, have acreage in the Trough.

According to PGS, the Rockall Tough has fewer than 10 wells per 1000sq km. Newcombe says that only two discoveries have been made in the Rockall area: Dooish, on the edge of the Trough in the northern Irish Rockall Basin; and Benbecula, in the northeast Rockall Basin in the UK sector. Legate says that six exploration wells have been drilled in the Rockhall Trough itself to date, largely in the 1980s and 1990s, and all were dry holes.

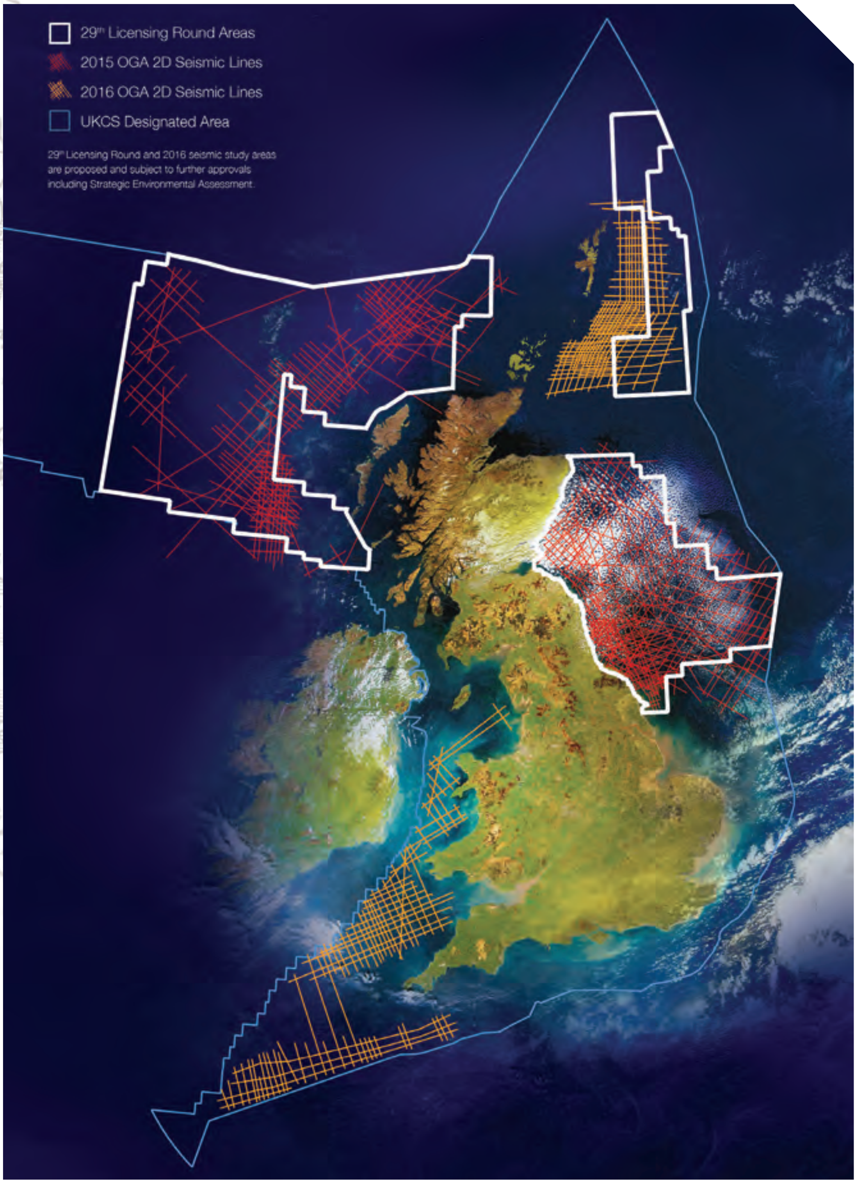
Some of the challenges in the Rockall are deeper waters, but also Basalt intrusions, which make mapping of migration complex. "It is deepwater and there has been a lack of data," Newcombe says. "There was a survey in 2014 by BP with better definition. It was the first shoot in that area. We now have 10,000sq km [in the area and] from that it will be hard to define a prospect to drill. But it can show the play potential in order to do more seismic."

Mid North Sea High

Unlike the Rockhall Trough, there are quite a few acreage holders, including majors and independents, in the Mid North Sea High. But still, it has been described as "one of the last remaining underexplored areas of the UKCS" by geoscience firm Polarcus, with a possible Devonian-Carboniferous petroleum system that hasn't been tested and has been hard to image.

Legate says that 23 exploration wells have been drilled in the Mid North Sea High, mostly in the 1960s-1980s. One well had gas shows and another oil shows, she says.

"The Mid North Sea High has in part been explored in the past, but it has lacked good quality data for the industry to create a deeper understanding of the geology," Newcombe says. Firms have also largely focused on the Permian in the past. "We have new data and reprocessed data, plus the BGS



Seismic lines – where last year's Rockhall Trough and Mid North Sea High seismic lines were shot. image from OGA.

(British Geological Survey) study on the northern North Sea Paleozoic. This will give people greater insight."

The new data is giving companies the opportunity to look at deeper horizons, he says. The BGS survey on the northern North Sea Paleozoic is also letting people see where plays extend into the onshore, from which they can extrapolate back to the offshore.

Licensing round

The Rockall Trough and Mid North Sea High will feature heavily in the 29th licensing round, a round likely to be light on license commitments, Legate says. Just seven well commitments were featured in the 28th round, which closed right at the start of the oil price crash. With frontier acreage involved, fewer well commitments can be expected this time round. More likely, data reprocessing or shooting seismic surveys could be expected.

This makes it an opportunity, Legate says. "It is an opportunity to pick up acreage cheaply with few commitments. Any work completed would benefit from the low cost base we are seeing, so there is a bit of an opportunity here. What is interesting is the new Innovate License, which gives companies up to nine years," she says. "Companies also don't have to prove financial capability. This could attract some of the smaller exploration and production companies to acquire acreage."

Instead of having different licenses, the Innovate License will have a phased approach with different steps, covering data reprocessing, seismic acquisition, wells, etc. "It is more flexible and pragmatic and gives us more flexibility to mature more of the work programs," Newcombe says. The bid scoring system is also being updated.

Go west

The next seismic shoot will focus on south west Britain and east of Shetland, which will be backed up by reprocessing legacy data in those areas. Areas to be targeted include Morecambe Bay, the Irish Sea, and the Minches and the East Shetland platform.

"People forget areas, like the Western Approaches," Newcombe says. "No seismic has been shot for 20 years there. All the Irish area has been covered, but not the British side. They drilled 20 years ago and didn't find anything massive, so it has been forgotten." Another forgotten area is western Britain, such as off Morecambe Bay where the Dragon discovery was made on the border with Ireland, he adds.

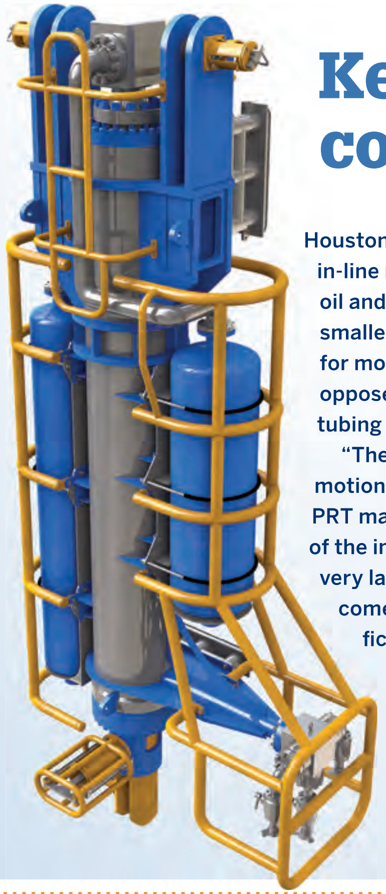
The Orcadian Basin in the East Shetland Platform could also prove prospective. It's another area with fewer than 10 wells per 1000sq km, PGS says. "People said it could be really quite prospective, but it's a different geology to Brent, it's slightly older, so in the past people kept to what they knew," Newcombe says. But, he says there's a similar high in this area to that on which Norway's massive Johan Sverdrup discovery was made. "[There has been] some taking from Norwegian learnings and looking at the Orcadian High," he says.

To further spur commercial activity, a £500,000 competition has been launched to encourage geoscientists and engineers to develop interpretations and products potentially using last year's new seismic data. Wells data from the Outer Moray Firth has also been released to industry.

The industry is also taking matters into its own hands. In the mature areas, a group of operators is working together to organize a "group shoot" seismic campaign. In addition, the BGS, working with industry and government funding, has completed its study of the northern North Sea Paleozoic potential, delivered to its operator sponsors this year. It is due to be released to industry more widely in 2017. This project aims to encourage research deeper and wider than conventional hydrocarbon horizons, covering the Mid North Sea High, Moray Firth and Orcadian Basin and the Irish Sea.

Some £700,000 funding has also been put into the Lyell Centre in Edinburgh, a joint venture between BGS and Heriot-Watt University. Pst-doctoral study in geoscience and reservoir engineering is also being funded. OE

Solutions



Keeping compensation in-line

By Audrey Leon

Houston-based PRT is bringing to market an in-line motion compensator for the deepwater oil and gas industry. The tool aims to provide a smaller, lighter and more versatile alternative for motion compensation on floating rigs as opposed to larger motion compensating coiled tubing lift frames (MCCTLF).

"These MCCTLFs have become the norm for motion compensation," says Patrick Placer, PRT manager responsible for the development of the in-line motion compensator. "They are very large, about 130,000lbs+. Most MCCTLFs come in multiple pieces, making them difficult to install and time consuming for rigging up."

PRT saw the opportunity to bring a new piece of equipment to market. "The in-line motion compensator is about one-third of the weight and footprint of MCCTLFs," Placer says, "which allows operators to put the tool on the rig ahead of time as opposed to having to wait until it is time to rig up and go directly to a derrick with it."

Because of the compact size of the compensator, operators' risk of delay due to weather conditions is reduced. "If they were using a MCCTLF, they would be dealing with larger bulky lifts that are more difficult and potentially unsafe," he says.

PRT was chosen through a competitive bid to help a Gulf of Mexico-based operator come up with a solution for an in-line motion compensation type system to take advantage of efficiencies for its rig operations. "Both drillships working the project had a need for compensation," Placer says. "We worked with the operator to come up with the operating parameters/limitations of the system in accordance with their project needs. We collaborated on the stroke requirements of the compensating system and the tensile requirements, to make the system unique to the deepwater market." www.prorentaltools.com

HAL offers GRIP well control services

Boots & Coots Services, a Halliburton (HAL) business, has developed the Global Rapid Intervention Package (GRIP), a suite of services to help reduce costs and deployment time in the event of subsea well control events.

GRIP provides well planning and well kill capabilities facilitated by HAL's global logistics infrastructure and existing product service lines. This includes both an inventory of well test packages, coiled tubing units and relief well ranging tools.

In addition, due to their size and weight, capping stack systems currently available can take weeks to deploy, and are expensive to transport and reassemble on a job site. To address these issues, GRIP features the new high temperature, 15,000 psi RapidCap Air-Mobile Capping Stack, which incorporates a specially designed gate valve-based system to make the system lighter. This allows RapidCap to be air transported on a Boeing 747-400F and lifted by a 110-ton or lighter crane, rather than requiring specialized infrastructure.
www.halliburton.com

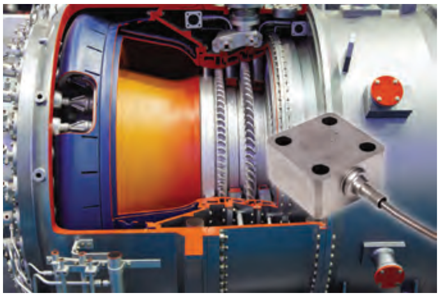
Archer's Point system locates leaks

Archer's new Point system, a well integrity resource, is designed to provide a proactive and systematic approach to integrity management, which integrates surface and downhole measurements, evaluates barrier sealing performance, and locates leaks and flowpaths. Ultrasound energy, generated by the turbulent flow of fluids through leaks and flowpaths in wells, can pass through fluids, steel and cement, which allows

detection behind tubing and casing. The Point system uses seven diagnostic programs underpinned by Archer's proprietary ultrasound technology to investigate or locate a range of failure types from the surface or downhole: CheckPoint, with three program options, is deployed at surface routinely to validate integrity or investigate a known integrity issue; LeakPoint, with two program options, is designed to expose leaks in the primary tubular, surrounding casings or completion equipment, and beyond the A-annulus—even while a well is flowing; FlowPoint, with two program options, is designed to diagnose complex failure scenarios by capturing the ultrasound energy and temperature anomalies created by turbulent fluid flow through barrier leaks and annular flowpaths.
www.archerwell.com

PCB releases new accelerometers

PCB Piezotronics has launched two new hazardous area approved differential output charge accelerometers from IMI



Sensors that are designed for use in high temperature applications. IMI developed the new sensors for gas turbine monitoring, commissioning of nuclear power plants and machinery monitoring in high temperature environments.

Model EX615A42 is designed for use in environments up to 260°C and offers sensitivity of 100pC/g, a measurement range of ±200g peak and a frequency range of 5kHz ±5%. The sensor has a stainless steel housing and features a 3m armored, low-noise PTFE cable terminating in pigtails.

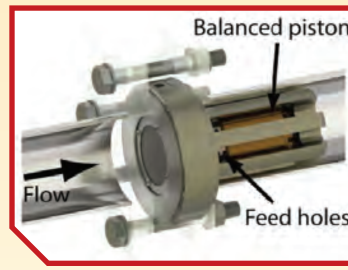
The second accelerometer – model EX619A11 – is capable of operation up to 482°C with sensitivity of 50pC/g, measurement range of ±500g and frequency range of 3kHz ±5%. This sensor has a nickel housing with an integral 2.1m MI hardline cable terminating in a 2-pin MIL-C-5015 connector.

Additional characteristics of the new IMI Sensors high temperature charge output accelerometers include ATEX approval, high shock survivability, high resolution and large dynamic range option. **www.pcbpiezotronics.co.uk**

Flow regulation

UK-based Oxford University engineering spin-out Oxford Flow has developed a piston-led flow regulator it thinks could help save space and cash in the oil and gas industry.

Created off the back of research and development into various applications such as gas turbines and jet engines, the Oxford Flow pressure regulator replaces the traditional failure-prone diaphragm with a piston.



Upstream relies on ball valves powered by actuators, these valves require hugely expensive uninterruptable power supplies to maintain safe operation. Traditionally diaphragm-led valves can't be used be used in this context, because they're so prone to failure through fatigue, erosion and embrittlement of the elastomers that provide the flexibility required.

The firm, which has backing from Oxford Sciences Innovation (OSI), says its regulator would enable an 80% reduction in weight over traditional devices and allow a 10x increase in flow capacity.

Benchmarking against current market-leading gas pressure regulators at Oxford University's Osney Thermo-fluids Laboratory showed that the technology either matches or exceeds existing designs across all performance parameters, says the firm.

"Testing reveals that our valves have a number of technical benefits, including increased accuracy, lower noise emissions, minimized flow turbulence and minimum pressure drop reduction," says Christopher Leonard, business development director, Oxford Flow.

"They also have several cost benefits. For example, their reduced size and weight has the potential to lower their installation costs, while the fact they have just one moving part means that they have an ultra-long service schedule, lowering maintenance and replacement costs. This technology has great potential to help offshore businesses greatly reduce their capital and operational expenditure, while at the same time improving performance and reliability." **www.oxford-flow.com**

Seatools develops HeaveMate

Seatools introduces an intelligent active heave compensation module: HeaveMate. This active heave compensator system can be integrated into both new and existing offshore and subsea equipment such as winches, cranes, and LARS systems.

HeaveMate can be delivered either as an OEM package with the essentials for heave compensation (black box controller with sensors and software) or as part of a complete turn-key system, including mechanical and hydraulic hardware. In any case, Seatools' simulation capabilities are applied to ensure proper performance of the overall system in any sea condition and situation (including failure cases), and pre-tune the controller prior to commissioning.

The system is currently deployed in a retrofit project in which a passively compensated LARS will be upgraded towards an actively heave-compensated LARS. **www.seatools.com**

RM5 measures slurry density

Red Meters has designed the RM5 in-line, a continuous density meter specifically for oil well cementing.

The RM5 calculates density by measuring direct mass over a known volume within a flow tube. This ability to measure abrasive media, like slurry, is due to the gum-rubber-lined cartridge with customization options for high pressure and extreme temperature applications. The interchangeable cartridge measures deflection caused by continuously changing weight within the slurry using laser interferometry.

Installed in-line, the RM5, delivers real-time density measurements by sampling at a rate of up to 3000 times per second allowing constant monitoring of a complete sample size across an array of applications. This enables the operator to know when the blend is homogeneous and what the density is in real-time.

By replacing nuclear density meters and auto samplers, early adopters benefit from an increase in accuracy of more than 2.5%, according to the company. **www.redmeters.com**

Activity

Images from Schlumberger.

Going for barite

For many, mining is a dying, if not already dead, industry in the UK. Yet, a new mine could be opened in 2018 to serve the oil industry. M-I SWACO, a Schlumberger company, is hoping to nearly quadruple its Scottish barite (Barium Sulphate) production through the proposed new underground mine in the Perthshire hills, Scotland.

If the plans for the mine, at Duntanlich, near Aberfeldy, near the famous picturesque "Queen's View," are approved, M-I SWACO could add 120,000-tonne of barite annually to its production from the 7.5 million-tonne deposit, according to the company's Project Plan Document. M-I SWACO says the deposit is a simple sub vertical, thick structure, of proven high quality, which would lend itself to mechanized mining methods.

Barite acts primarily as a weighting agent to increase the density of drilling fluids, where it functions to confine high hydrostatic pressures due to oil, gas and water released by drilling and thus prevents blowouts. The firm says there's no substitute that could be used.

M-I SWACO currently operates a barite mine at Foss, also near Aberfeldy. It has been in production since 1985 and produces 42,000-tonne a year.

From Foss, the barite is transported to M-I SWACO's operations in Aberdeen. Once milled there, it is dispatched by ship directly from Pocra Quay to North Sea oil and gas platforms. Barite is also shipped from Perth Harbour to a mill at Great Yarmouth.

Duntanlich would be expected to operate for about 50 years, says the company A decision on the plans for the mine is due to be made by early September.

–Elaine Maslin

Tenaris opens Thai center

Tenaris has opened its first service center in Thailand in order to serve Chevron.

From Songkhla, an harbor on the Gulf of Thailand, Tenaris will supply the major OCTG and Rig Direct services. Tenaris will provide 80,000-ton of chrome and carbon casing and tubing, along with TenarisHydril premium connections.

As part of Tenaris' Rig Direct service model, the Songhkla service center will provide complete pipe management services, including demand planning and inventory management, preparation for running offshore, PipeTracer pipe by pipe identification, and net invoicing. These services are designed to help Chevron improve operation reliability and efficiency while reducing the total cost of operation.

AFGlobal to acquire MHWirth subsidiary

Houston-based AFGlobal has agreed to acquire Managed Pressure Operations (MPO), a subsidiary of MHWirth. The resulting combination of companies will offer technologies covering both onshore and offshore applications, including deepwater managed pressure drilling (MPD).

The new business group within AFGlobal's oil and gas segment will be known as Advanced Drilling Systems. The complete portfolio will include riser gas management systems, early kick/loss detection, MPD, dual gradient drilling and continuous circulation.

Wood Group, Librestream agree to collaboration

Wood Group and Canadian technology company Librestream Technologies have formed a collaboration to provide solutions for operations, maintenance, and integrity challenges in the oil and gas sector. The solutions will combine Wood Group's industry knowledge with Librestream's real-time virtual video collaboration digital application.

Under the partnership, Wood Group and Librestream will also co-develop a number of discrete new technologies designed to reduce the time for problem solving and associated implementation,

BP and Aker unite off Norway

Norway was the focus of another major merger earlier this year with BP Norge, Det Norske and Aker – which owns 40% of Det Norske – agreeing to combine into a single company to be named Aker BP. Aker will own 40% of the new company, with BP and Det Norske holding 30% each. The deal is expected to complete by the end of the year.

Aker BP – set to be the largest independent on the Norwegian Continental Shelf - will hold 97 licenses, 46 as operator, 723 MMboe of P50 reserves and, in 2015 figures, 122,000 boe/d of production. In a joint statement, the companies suggested they could grow production to 250,000 boe/d by the early 2020s.

Several BP fields are brought into the new company – Skarv in the Norwegian Sea, plus Valhall, Hod, Ula and Tambar in the North Sea. Det Norske will contribute producing fields Alvheim, Volund, Vilje and Jette, the Ivar Aasen development and it is a partner in the Johan Sverdrup project

BP CEO Bob Dudley signaled the way ahead for the merger: “The Norwegian Continental Shelf represents a significant opportunity going forward and we are looking forward to working together with Aker to unlock the long term value of the company through growth and efficient operations.”

– John Bradbury

thereby increasing productivity at remote sites both onshore and offshore.

FORESEA funds ocean energy testing

The US$12 million FORESEA (Funding Ocean Renewable Energy through Strategic European Action) project is bringing together European ocean energy test facilities to help the demonstration of tidal, wave and offshore wind energy technologies in real-sea conditions.

FORESEA will offer a series of funding and business development support packages to TRL 5+ ocean energy technology developers seeking to test and demonstrate in real-sea and grid-connected conditions, and leverage the further investment needed to take their product to market.

Led by the European Marine Energy Centre (EMEC), the FORESEA project will provide funding support to ocean energy technology developers to access Europe’s world-leading ocean energy test facilities: EMEC (Orkney Islands, UK), SmartBay (Galway, Ireland), SEM-REV (Nantes, France), Tidal Testing Centre (Den Oever, Netherlands).

The FORSEA project is funded by the Interreg NWE (North-West Europe) program, part of the ERDF (European Regional Development Fund), and the test centers will be supported by European industry group Ocean Energy Europe, based in Brussels.

PEOPLE

Spotlight

The drive to improve

Brazilian native Luis Araujo became CEO of Aker Solutions in 2014, after joining the business in 2011. He has a BEng in mechanical engineering and an MBA. We asked him about his career and outlook on the industry.

Luis Araujo Photo from Aker Solutions.

What attracted you to a career in the oil and gas sector?

I've always been curious about new technologies. When I began my career as a mechanical engineer, Brazil was at the forefront of deepwater exploration and just starting to build an industry. This provided huge opportunities for someone with the right background and ambition. The deepwater record was just above 300m. There was a lot to explore and I knew I could have an exciting technical career. Also, the industry is multicultural and I wanted to be part of that.

What did you aspire to do when you were younger?

I've been an athlete most of my life, playing water polo at quite a high level. I enjoy the challenge of competing and the drive to improve. I found the oil industry stimulating because it had the same push to excel and it also let me be part of a team.

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

I had progressed from offshore work to engineering subsea design. I had been part of pushing technical boundaries with some patents to my name. But, I wanted to learn more – to understand the whole – so I took an MBA in Scotland in parallel to my job as an engineering manager. That was a turning point. I took on more commercial roles, learnt more about project management and eventually decided that I wanted to run companies.

The market has changed dramatically since you took over as CEO. What's been your response and how do you see this developing further?

There are tough choices to be made, but also opportunities, in the current environment. We're now able to make changes that our customers simply weren't ready for two years ago. These include changes in how we approach both field and technology developments. There is a huge push to cut costs and find more effective ways of working. At Aker Solutions we've reduced costs for some developments by as much as 50%. But, we need to do even more as an industry to improve and implement changes so that we can see standardization on a broader scale and move toward needed industrialization. This means making a major change in how we work together. Aker Solutions has formed partnerships with peers, such as ABB, Baker Hughes, MAN Diesel and Saipem, where our capabilities complement each other in key areas. Together we're generating ideas and solutions that we couldn't have done individually. We're also finding more collaborative ways to work with clients.

You have a lot of experience in the subsea business – at Wellstream, GE, ABB and FMC. What moves does the wider industry need to make to thrive in the volatile price world?

I've mentioned the need for greater collaboration. But, collaboration won't mean much unless it leads to innovation and technological progress that drives our industry forward. As an example, our alliance with MAN Diesel is building on the technology developed for the world's first subsea compression system. We're developing slimmer, more cost-efficient systems that can be used at even the smallest subsea fields. Our calculations show that we can reduce the size and weight of these systems by as much as 50% without changing their core functionality.

Innovation needs to address the market challenges. But, we also need to be on guard and ensure that the current focus on cash flow doesn't stifle the industry. If we stop investing in new solutions, processes and technologies it will become much harder to win the improvements needed.

What exciting technologies or trends is Aker Solutions keeping an eye on?

We're increasing our efforts in digitalization across the company by enhancing our process efficiency using knowledge-based engineering tools. Smart and connected products are being developed that will enable new service offerings for life-of-field performance management and technologies are developed that enable automated and remote operations.

We're also seeing growing interest in our carbon capture and storage (CCS) technology. CCS needs to be part of the toolbox to reach global emissions reduction targets and our technology is qualified for cement plants, coal and gas-fired power stations and now recently, for the first time anywhere, waste-to-energy production. OE

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WORKSHOP:

TUESDAY, AUGUST 30

Redeployment of Existing Units: Challenges and Opportunities

The importance of reducing cost is driving high interest in FPSO redeployment. Although simple in concept, a redeployment requires careful planning and analysis of strategic technical, location, and commercial drivers.

This practical, hands-on workshop will combine a real-world case study with insights from industry experts to give participants valuable guidance for evaluating, planning and executing a successful redeployment project.

SESSIONS:

WEDNESDAY, AUGUST 31

Session I:
The Stones Development

Session II:
Panel Discussion:
Challenges of Financing Capital Assets

Session III:
FPS Hull Selection Drivers

Session IV:
Options for Gas Developments

THURSDAY, SEPTEMBER 1

Session V:
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Session VI:
Standardization – Where Are We Now?

Session VII:
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Joint Industry Project on Best Practices for FPSOs

OUR KEYNOTE SPEAKERS:

TUESDAY, AUGUST 30

A Historical Perspective on FPSO Redeployments

Bruce Crager
Executive Vice President,
Endeavor Management

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An Update on the Stones Development

Curtis J. Lohr
Stones Project Manager
Shell Projects & Technology:
Deepwater Projects - Americas

THURSDAY, SEPTEMBER 1

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Photo from Shell.

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