upstream technology

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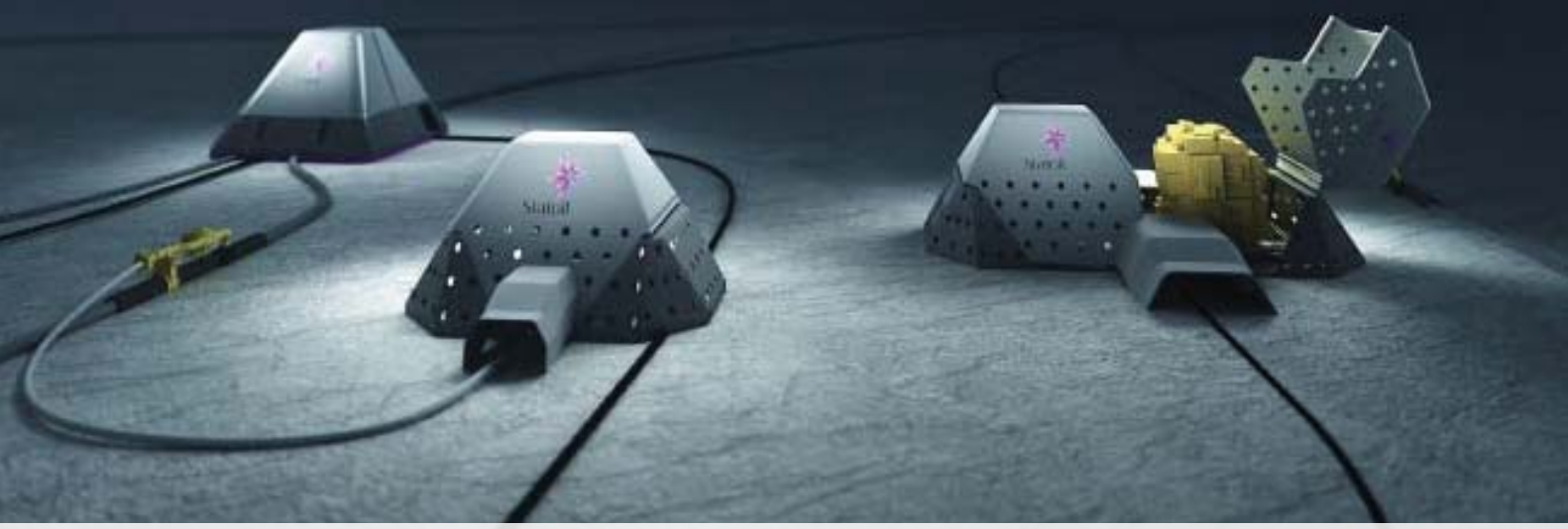
Subsea strategy:
Planning for a platform-free future

Tie-in times:
Making good use of existing infrastructure

Firm footing

Bold steps ahead for Barents E&P



Vessel opportunity:
Compact deck kit for composite pipe deployment

See serpent:
Subsea inspection with a twist

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Photo: Reuters/Scanpix

Strength in pacts

After a year-long engagement under the Forsys Subsea banner, FMC Technologies and Technip announced in May a $13 billion merger of the two companies to form TechnipFMC. The union, assuming it proceeds as planned, will give the company about one-fourth of the subsea market and propel it to the top tier of oilfield services providers by revenue. The announcement came just weeks after Schlumberger finalised a merger with Cameron, its joint venture partner in OneSubsea — and, it should be noted, shortly after the proposed marriage of Halliburton and Baker Hughes, the second and third-largest oilfield service companies, was scotched by the US Department of Justice.

The companies say consolidation will hasten the integration of subsea services, encourage long-sought standardisation in equipment and processes, and help rein in the cost of subsea developments by optimising production systems from the early design phase throughout the life of a field.

One aim of these alliances is to avoid what Subsea 7 technology chief Thomas Sunde, in an interview in this edition, calls "the recycling of bids", the re-evaluation of projects for lower-cost alternative development options in the face of escalating costs and a suppressed oil price. Many hours have been lost in preparing bids for projects that are then delayed, if not cancelled outright — the "life-of-field" approach made possible by these subsea alliances, their advocates say, will go a long way in controlling costs and avoiding surprises.

Technology's role in this evolution cannot be understated. As Douglas-Westwood research director Steve Robertson commented recently, despite the prolonged low oil price, subsea hardware will continue to be "a critical option for future developments, as new reserves are discovered in remote and deep-water basins". Add to that the challenges of small, stranded pools and high-pressure, high-temperature reservoirs — also discussed herein — and continued investment in subsea R&D seems assured.

In a new report, the consultancy sees some hopeful signs in the subsea hardware market, projecting a total global expenditure of $94.3 billion from 2016 through 2020 — a 19% decline from the preceding five-year period, but still robust. The report notes a "long-term shift in the use of energy" toward cleaner burning fuels that will encourage subsea development of conventional gas in East Africa and other remote locations. The report notes: "Rapid technological progress within the industry will be required to ensure the economic viability of many marginal fields and remote discoveries."

As this edition was going to press, the fate of another alliance — between the UK and the European Union — was an open question. What impact a so-called Brexit would have on the North Sea oil and gas industry was also a matter of debate, with some warning of widespread market repercussions, others insisting that the most important business considerations, such as taxes and regulation, are determined by the UK government, not the EU. The real threat, they say, is a reversal of the modest but encouraging gains in the oil price we've seen in recent months. That is something upon which people on both sides of the aisle can probably agree.

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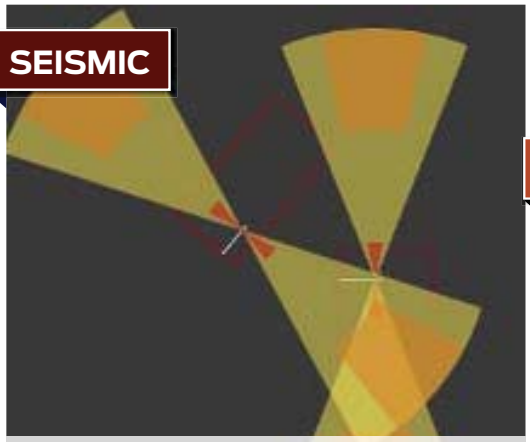


SEISMIC

Demystified

Also in this edition:

A walk in the cloud

First production is almost three years away, but cutting-edge technology is allowing Maersk Oil engineers to virtually inhabit the Culzean topsides now — and to plan a safer, more reliable operational phase, writes **Rob Watts.**

Some companies believe iPads and tablets will, in the near future, be just as important tools on oil and gas platforms as spanners and wrenches are today.

One of those putting such ideas into practice is Danish operator Maersk Oil, which recently embarked on the construction of three topsides for the technically challenging high-pressure, high-temperature (HPHT) Culzean gas and condensate scheme, located in the UK central North Sea.

Project director Martin Urquhart says digital technology is at the heart of efforts to deliver a "truly 21st century platform" both in the design phase and eventually during the operational phase.

Maersk, he says, will combine a number of technologies to optimise production efficiency, boost uptime and run a safer, more reliable plant. Importantly, they will also help to "future-proof" the Culzean facilities.

"Understandably, the focus on the capital expenditure phase of a new development tends to be the most intense. But any new project with thorough front-end loading will be planning facilities for the operational expenditure phase of the project simultaneously," Urquhart explains.

Because of the nature of dry-tree HPHT developments, it has been impossible to fully automate Culzean, he adds. However, Maersk has been able to embrace cutting-edge control systems and onshore monitoring that will minimise the number of people required offshore, which helps to cut costs and minimise risk.

"This will allow positions that would traditionally have been on the platform to be onshore, working in real time."

Urquhart estimates the efforts will lead to operational savings of at least $10 million per year.

Digital integration

The ultra-HPHT Culzean development, featuring three platforms linked to a floating storage and offloading unit, is major by any scale. Due on stream in 2019, it is expected to produce enough gas to satisfy 5% of UK demand when it reaches peak production of 60,000 to 90,000 barrels of oil equivalent per day, making it strategically important not only for Maersk, but also for the UK overall.

Equipment and materials will be pushed close to current technological boundaries in order to cope with the massive 13,500-psi pressures and 170-plus degrees Celsius (338 degrees Fahrenheit) temperatures in the Culzean reservoir.

Engineering house KBR, contracted directly by construction contractor Sembcorp Marine Offshore Platforms (SembMarine), is carrying out the detailed design of the decks after earlier performing the front-end engineering and design work directly for Maersk.

About 330 KBR staffers are working on the project, with around 200 of them based at its Singapore offices, close to SembMarine's Admiralty Yard, where construction is taking place.

Much of the technology being deployed on Culzean's platforms,

Images: Maersk Oil

TOWERING TRIO: An artist's rendering of the Culzean development in the UK North Sea. The ultra-high pressure, high-temperature field is scheduled to come on stream in 2019.

"Using digital technology makes us more efficient, but crucially, it also keeps us safer."

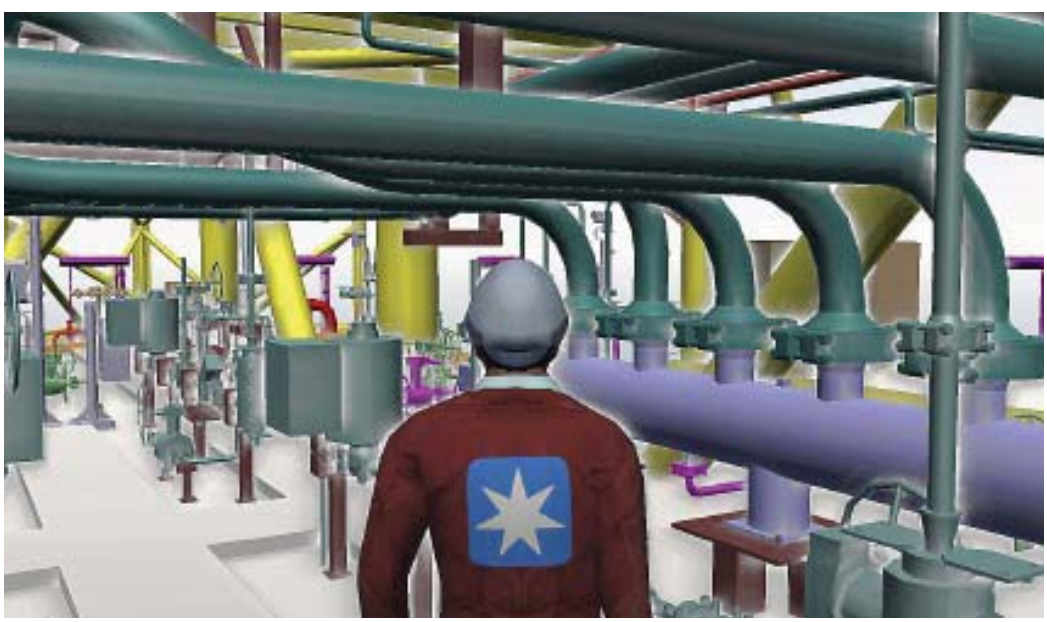
Martin Urquhart, Maersk Oil

while relatively new, has been used before, Urquhart admits. But he adds: "What's unique about what we're doing is that we have the luxury of being able to integrate it all upfront to maximise efficiency and safety, now that the digital capability is sufficiently mature. To my knowledge, I don't know of any platforms that have used this full combination of digital tools before."

Data delivery

Urquhart reckons that perhaps 20% to 30% of an offshore operator's time is spent seeking data in order to be able to perform a task. "That's hours every day looking for work sheets, valve specs and procedures. Better data management on the worksite can significantly reduce this by providing real-time information," he says.

To speed up procedures, Maersk



IN DETAIL: Sophisticated software such as COMOS Walkinside from Siemens allows engineers to carry out virtual tours of the facilities long before they are built and installed. Once constructed, the entire topsides will be scanned with lasers to validate the virtual model.

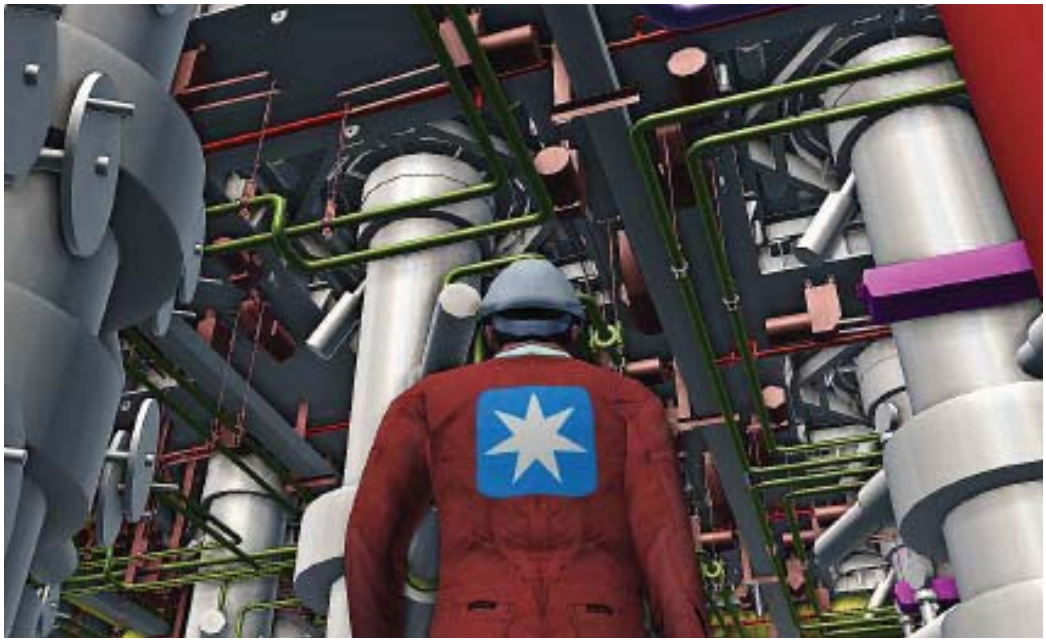
»

» will be placing radio frequency identification (RFID) tags on all pieces of critical Culzean equipment, such as valves.

When scanned using a tablet, staff will be presented on screen with bundles of information, from manufacturing data and certificates, to drawings, video simulation of maintenance or operations activities and maintenance history.

Workers will also be able to perform routine maintenance prompted by a checklist that will be available on the hand-held screen, he says. And they will be able to store photos and comments about the work for future reference.

What is more, any action that needs to be taken will be assigned a priority depending on the importance of the equipment, with closure tracked using industry-standard reporting dashboards.



EYES FORWARD: Walkinside uses gaming technology to allow an avatar to carry out a virtual tour of KBR's CAD design of the Culzean facilities. Using a gaming control pad, engineers can view exactly how a human being will interact with their designs, and avoid potential problems.

Operations

Crucial to all of this will be the flooding of Culzean's process decks with robust secure Wi-Fi networks.

This will mean that any work carried out on equipment or any other action taken will be synchronised instantly with a master data set, with notifications automatically posted to the relevant operations management and support teams both onshore and offshore.

"What we hope is that when we have the maintenance routines in the system, the workforce will have a tablet. They will walk up to, for example, an electrical junction box that has a tag on it, scan it and up will come all the records for that junction box.

"But not only that. If equipment has to be maintained in any way, colleagues will be able to view a recorded visualisation showing him or her what to do during the maintenance," says Urquhart.

It is a critical assistance for a facility that will have "umpteen million moving parts".

This modernisation of maintenance routines would not have been possible without the development of a robust virtual model of process equipment during the design phase, now taking place concurrently with construction.

Maersk engineers can already immerse themselves in many aspects of the future platforms, long before they have been built, thanks to the use of software systems such as Siemens' COMOS Walkinside.

One feature of Walkinside is its use of gaming technology, which allows an avatar to carry out a virtual "walk around" of KBR's CAD design of the Culzean facilities.

Using a gaming control pad, engineers can use Walkinside to view exactly how a human being will interact with their designs and avoid problems that would not necessarily be immediately evident otherwise.

"A valve might have ended up two metres in the air and in order to operate it the guys had to build a scaffold every time they wanted to maintain the valve," Urquhart says, citing a problem known to have occurred on platforms built earlier.

Walkinside will also assist during the operational phase, giving onshore control staff the opportunity to see equipment from exactly the same viewpoint as an offshore operator carrying out maintenance.

Once constructed, the entire topsides will be scanned with lasers to validate the virtual model, leading to the creation of an exact virtual replica of the facilities.

"Although the model is what should get built, there are likely to be a few changes made on site. In order to capture those, we are going to laser scan the entire topsides and validate the scan against the model," Urquhart says.

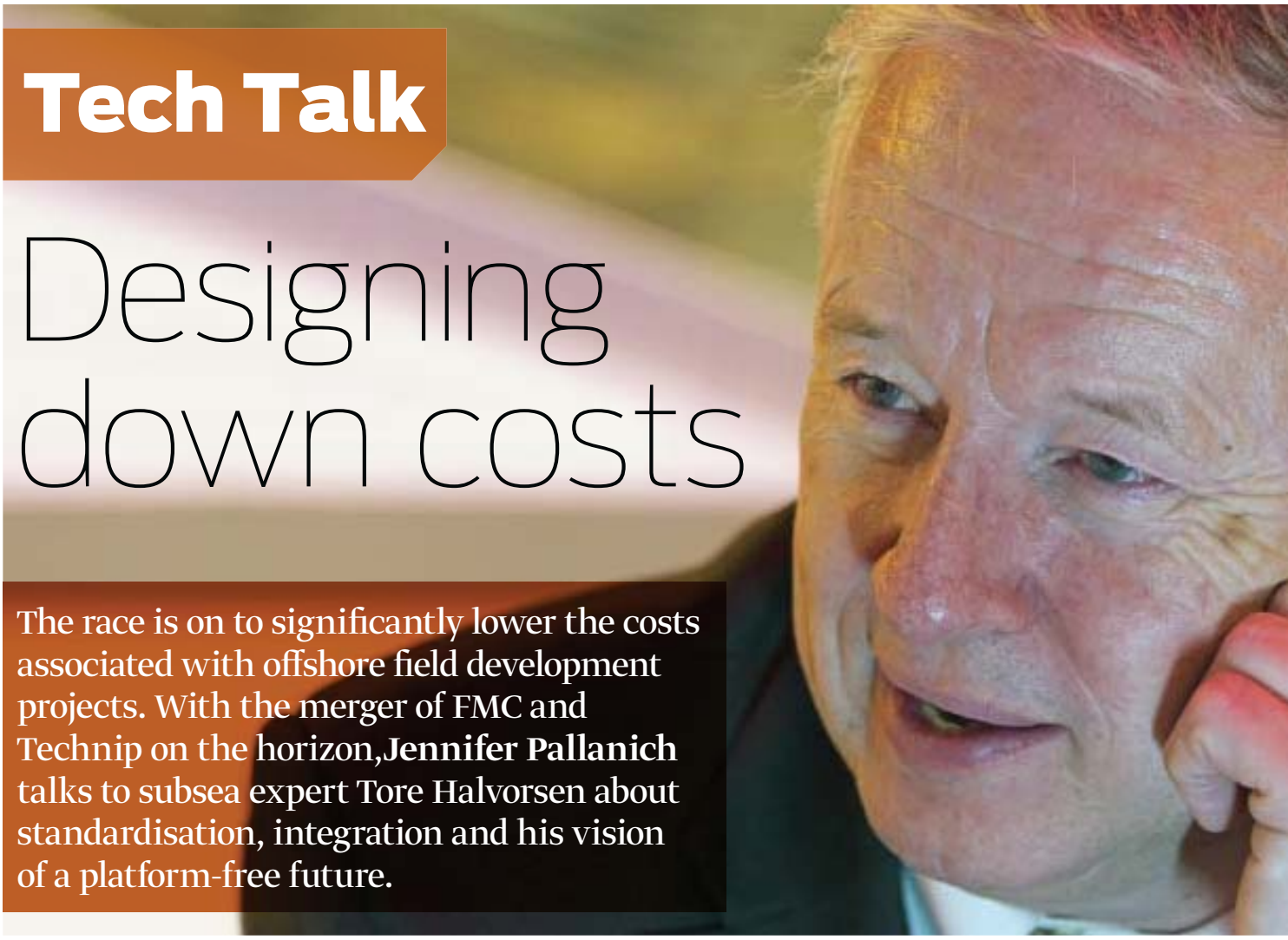
"So everything on the topsides will be checked to within a laser beam definition."

With 24-hour onshore-offshore links established through what Urquhart describes as an "integrated collaborative environment", a helping hand from "the beach" is always available.

This will replicate the offshore control room and provide the ability to not only monitor and control the plant, but also enable remote optimisation and testing without necessarily having to mobilise onsite engineering support.

For Urquhart, that is not only an important aspect of operational efficiency, but ultimately, safety.

"What everyone wants is the safest platform possible for our colleagues. The more we can do to have robust processes that minimise the need for human intervention, the safer the environment should be. So yes, using digital technology makes us more efficient, but crucially, it also keeps us safer."



Tech Talk

Designing down costs

The race is on to significantly lower the costs associated with offshore field development projects. With the merger of FMC and Technip on the horizon, **Jennifer Pallanich** talks to subsea expert Tore Halvorsen about standardisation, integration and his vision of a platform-free future.

Despite the rocky financial environment, FMC Technologies has maintained its investments in research and development.

"All the R&D we have, except for (high-pressure, high-temperature), is focusing on designing away costs from our systems," says Tore Halvorsen, senior vice president for global subsea production systems.

While some companies may have slashed R&D funding levels to survive low oil prices, FMC Technologies (FMCTI) is betting R&D will help the company prepare for the future in two ways. One paves the way to all-subsea developments, and the other aims for technologies that can reduce costs by up to 50%.

"If you dial forward, our dream is to have an all-subsea development of an offshore field," he says.

The industry has already made great strides in designing equipment for the seabed, but there are still key pieces, such as full seabed processing and subsea storage of oil, that have not been possible yet.

"Everything we do is preparing for that ultimate stage where offshore fields are developed platform-less," Halvorsen says, citing as an example the InLine ElectroCoalescer. The system, which removes droplets of water from produced oil and prepares the oil for storage, is a quarter to half the size and weight of other electrostatic coalescers. It received a Spotlight on New Technology Award during this year's Offshore Technology Conference in Houston.

Halvorsen believes it likely that FMCTI will have all the pieces in place for the platform-less field shortly after 2020.

Cutting costs

A combination of standardisation, integration and technology will all be required to halve costs. "You can't reach this goal by only attacking one," Halvorsen says. "Operators need to be more open to ideas."

The offshore industry has been stuck in one method of operations for far too long, he says. "We are 40 years old as an industry, and the basics of industrialisation haven't happened," he says. "Each operator still has their own material specifications."

Offshore field sizes have changed over those decades as well. "The luxury of having large fields to develop and operate have in a way prevented [standardisation] until now," he says. "If you have a big field with 40 subsea wells, you have the volume, you don't feel the urge to standardise across another field of 40. However, the situation today is that the world of large projects is not there anymore."

FMCTI and other subsea vendors are working to have operators accept vendor-based specifications for foundation items such as materials, welding and painting.

"That doesn't mean every single (piece of) subsea equipment has to look the same, but that the fundamentals like material, welding and painting can be accepted across all operators," he says. It is not necessary to standardise on the end system to achieve the effect of standardisation on cost as long as the component fundamentals can be standardised.

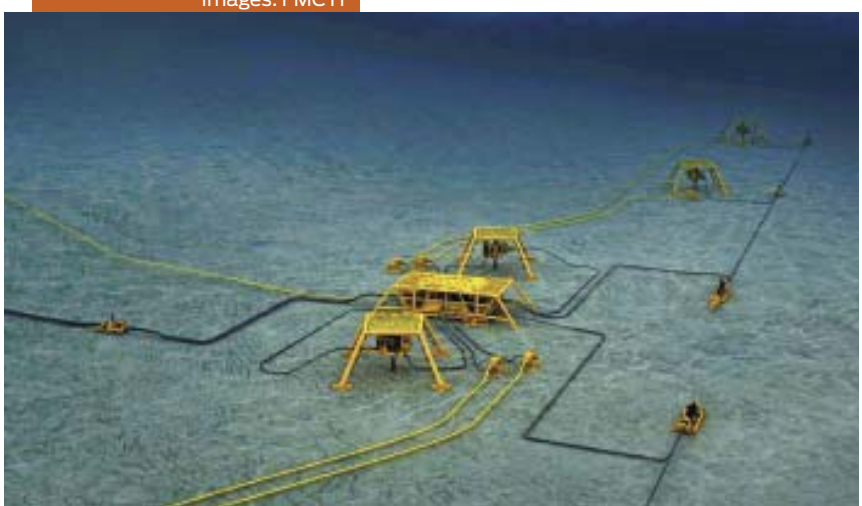
Operator acceptance of vendor-based specifications is gradually coming through, Halvorsen says. "It doesn't happen overnight, but we see movement."

FMCTI is in the same boat as far as its own subcontractors go.

Photo: Khalil AbuSharekh

Images: FMCTI

SPACE SAVER: FMC Technologies' InLine ElectroCoalescer removes droplets of water from the oil and prepares the oil for storage. The machine is one-fourth to one-half the size and weight of other electrostatic coalescers.



SEAFLOOR SOLUTIONS: The subsea industry continues to move more production operations to the seabed. FMC Technologies is pursuing a "platform-less" future.

"We will have to turn around to our subcontractors and say, 'I accept your standard, I accept your way of doing things'. Otherwise, this won't work."

Such measures are necessary to reverse a decade of spiralling subsea costs, he says.

"We have quadrupled the costs over the last 10 years in the subsea deepwater business. To halve the cost should be obtainable." Volume can generate 20% to 25% savings, he says, while integration can yield further cost reductions.

The 2015 Forsys Subsea joint venture with Technip offered integration of services (see Upstream Technology 3/2015). In May 2016, FMCTI and Technip announced a $13 billion merger of the two companies. The combined entity, TechnipFMC, will build on the Forsys Subsea venture and further integrate services and technologies. The move reflects an industry trend to a more "holistic" approach to subsea developments. "We are convinced that having people like us earlier involved will have better solutions than waiting to call us in at a later stage," Halvorsen says.

"Everything we do is preparing for that ultimate stage where offshore fields are developed platform-less."

Tore Halvorsen, FMC Technologies

FMCTI is focusing on step changes in technology to help drive costs down. Historically, the industry has not been challenged to design for low-cost equipment but rather for functionality. "To be challenged by step change is fun, to be challenged by incremental change is not fun," he says.

The biggest cost reductions could result not from incremental changes, but from more dramatic changes in the way subsea fields are designed.

"You can squeeze the cost of a valve only to a certain limit. The step change in cost comes when you can remove it."

Most people probably do not think of technology as capable of cutting costs, he says, but he believes the technology piece can probably bear the biggest results.

In the effort to cut costs, Halvorsen says, "technology is more critical than ever."

The company has a number of initiatives aimed at reducing the cost of equipment such as trees, controls, manifolds, and tie-in systems. Switching to all-electric subsea controls will eliminate large umbilicals, he says. Removing the jumper, or interface between the flowline and manifold, is a simple way to reduce equipment and installation time.

Halvorsen calls oil prices "a very good accelerator" for motivating operators to be receptive to new cost-saving ideas in standardisation, integration and technology.

"We can't let this low oil price scenario go to waste. We have to use this opportunity to make a step change in all these three areas," he says. "We definitely see the light at the end of the tunnel."

Subsea cost cutter

Statoil has developed a new concept for delivering lower-cost horizontal subsea wells in shallow reservoirs, aimed at improving the commerciality of the Barents Sea. In this exclusive report, Terry Knott learns more from the company's subsea team leaders.

As the old adage tells us, "necessity is the mother of invention". A short and pithy observation, which time and again has proved true for the offshore industry as it has come up with new ideas for pushing back the frontiers of exploration and production. And no better time than now for more of that necessary and inventive thinking as operators seek ways to tackle the double hit of rising offshore development costs against a backdrop of prolonged low oil prices.

For Norway's Statoil, meeting the challenge of reducing offshore costs, particularly for subsea developments, stepped up a gear some three years ago.

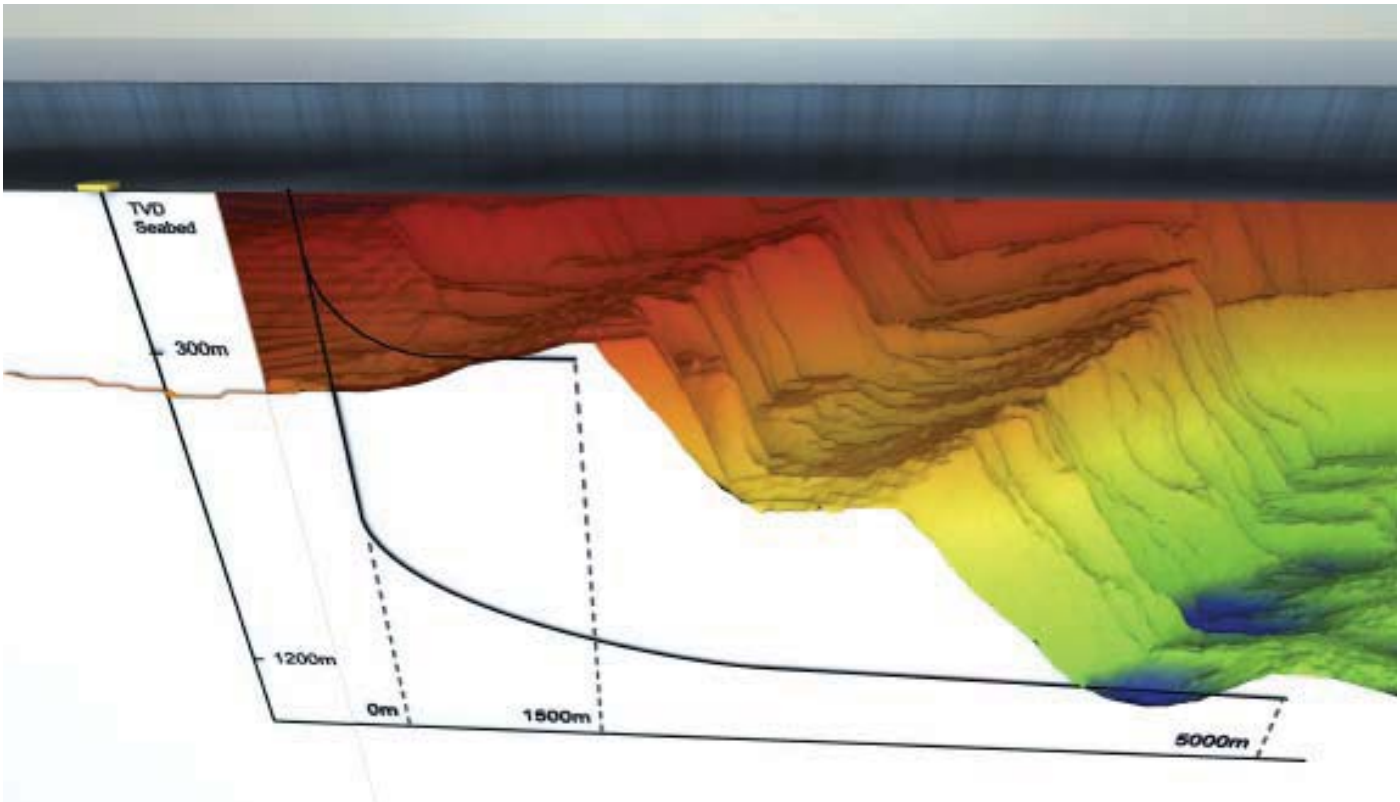
"Between 2003 and 2013, subsea development costs increased by 300%," says Rune Mode Ramberg, chief engineer for subsea technology with Statoil. "On top of this, the industry has been hit by lower oil prices, which have significantly squeezed commercial margins. Clearly we need to change something, to make adjustments in our approach to offshore developments — we're in this for the long term whatever the oil price does, so it is imperative we find ways to develop fields with greater economic efficiency."

Driven by this cost imperative, in 2013 Statoil began an in-depth evaluation of its methods of field development, pinpointing where the costs lie and focusing on how these might be reduced. While the evaluation programme encompassed all aspects of offshore development from reservoir to production, in Statoil's case, understandably, the subsea sector has received the lion's share of attention — the company currently operates almost 540 subsea wells, delivering over half of its hydrocarbons production.

"We have many more subsea

SITTING PRETTY: Statoil's new Cap-X concept will enable multiple subsea wells to be closely spaced above reservoirs while promising to cut well costs by up to 30%.

Images: Statoil



WELL PATHS: The graphic shows the rock overburden (in colour) above a hydrocarbon reservoir located at around 1200 metres true vertical depth below the seabed. The well reaching the reservoir has sufficient depth to make a gradual transition to the long horizontal section. However, a shallow reservoir at around 300 metres below the seabed, typical of those found in the Barents Sea, requires a steeper angle of approach. The advantage of Cap-X is that the angle of the well can start to be built higher up in the overburden, reducing the risk of shallow horizontal drilling and its associated costs.

» prospects in our future portfolio," adds Ramberg. "Not only large fields, but reservoirs requiring just a few wells, and smaller satellites near to existing infrastructure. It is important we understand more precisely what drives the costs on these so that we can maximise their commerciality. Of particular relevance in this respect is the additional challenge we face of heading north to new territory — into the Barents Sea."

Barents build-up

Interest has been steadily building in the hydrocarbon potential of the Barents Sea, stimulated by recent discoveries in the south of the Norwegian sector of the region, including Wisting, Gotha and Alta. These lie generally to the north of Hammerfest in the area of Statoil's producing Snohvit field, and the promising Johan Castberg field, itself consisting of three oil discoveries and which is now awaiting a final decision from Statoil and its partners for development to proceed.

Now, through its 23rd Licensing Round, Norway has opened up an entirely new area for exploration in the south-east Barents Sea, which was agreed to be Norwegian territory under the border agreement with Russia that came into effect from 2011.

According to the Norwegian Petroleum Directorate (NPD), of the 57 licence blocks made available for bidding in the current licensing round, 54 of these are in the Barents Sea, with 34 of them lying in the hitherto unexplored southeastern area. Bids were received for all 57 blocks or portions of blocks from 26 oil and gas companies, says the NPD. The outcome, announced on 18 May, is an offer of 10 new production licences in the Barents Sea, three of these being in the southeastern area, with the NPD hoping the first exploration well will be drilled here in 2017. Statoil was awarded five of the 10 licences, four as operator and one as partner — two of the operatorships and the partnership are located in the new southeastern area.

The development challenges of the Barents Sea are significant, including its Arctic environment, remoteness, long distances from infrastructure, an active fishing industry and long periods of darkness in winter, to name but some. However, another less evident challenge relates to the nature of many of the hydrocarbon reservoirs in the region.


Photo: Harald Pettersen/Statoil

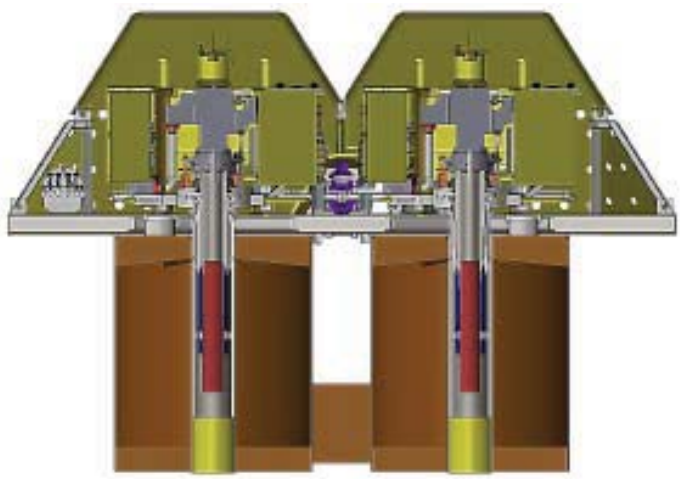
"Statoil is in this for the long term whatever the oil price does, so we must find ways to develop fields more economically."

Rune Mode Ramberg, Statoil

"The water depths in the Barents Sea are generally moderate, around 250 to 500 metres," notes Bjorgulf Haukelidsaeter Eidesen, leader for subsea technology and research with Statoil. "However, the hydrocarbon reservoirs lie at relatively shallow depths below the seabed. Not only does that demand the drilling of many horizontal wells from multiple locations to drain these reservoirs, it also poses difficult technical challenges, accompanied by a higher price tag."

He points to Barents Sea reservoirs located up to only a few hundred metres below the seabed under a relatively shallow rock overburden. The industry is well versed

STRONG SUPPORT: The suction pile provides the foundation for Cap-X, transferring all loads into the seabed, including the weight of the well and the blowout preventor stack during drilling, and can withstand subsea tie-in loads and impacts from trawling gear.



SHORT CONDUCTOR: Arrangement for a dual well Cap-X. The cross section shows the short conductors, around eight to 10 metres long, pre-installed inside the suction piles, with the completed wellhead housed in the top structure. The short conductor permits the transition from vertical drilling to horizontal drilling to begin sooner in the well path, giving more economical access to shallow reservoirs.

in drilling horizontal wells at greater depths below a much thicker overburden of rock, say 1000 metres down or beyond (see diagram opposite). Critically, this greater depth allows the trajectory of a well to be gradually deviated from vertical to horizontal, and then to reach out in a long horizontal section into the hydrocarbon-bearing reservoir. But with shallow reservoirs, turning to the horizontal has to occur closer to the seabed.

"At the top section of a conventional subsea well, you normally have a long vertical conductor pipe penetrating into the seabed and cemented into position," says Eidesen. "This is typically 60 to 100 metres long, although it may be shorter in the case of a shallow reservoir, say 40 to 60 metres. But the path of the well cannot begin the transition towards the horizontal until the drillbit is well below the conductor. For shallow reservoirs there is not much distance between the conductor and the target payzone in the reservoir to allow the gradual transition from vertical to horizontal. Drilling a well this way involves a steeper approach angle that can present operational risks, and it can also be costly."

Finding a solution to this particular Barents Sea problem was not a separate activity undertaken by Statoil in isolation, emphasises Eidesen. Instead it was just one part of the company's overall subsea cost-reduction programme, the greater goal being to simplify and standardise the hardware interfaces for subsea wells in order to get development costs down. The net result is that not only has Statoil devised a way to tackle the challenges of drilling horizontal wells in shallow reservoirs, it has also evolved a concept for installing subsea wells at significantly lower cost, one that promises to have an impact not only in the Barents Sea, but also in other offshore provinces.

Statoil believes its new concept could significantly cut the cost of bringing a subsea well into operation by up to 30% — and has appropriately named it as Cap-X.

Firmer foundation

In essence, Cap-X — a proprietary concept now trademarked by Statoil — is a combination of proven technology and new thinking, packaged together in a smart way.

At the heart of Cap-X is a suction pile, designed to provide a very firm foundation set in the seabed, both for the drilling of a horizontal well, and for supporting the completed well and wellhead. The pile, resembling an upturned cylindrical steel bucket, is around five metres in diameter and some eight to 10 metres deep, depending on prevailing seabed conditions. Installation will be achieved in the conventional way for suction piles by lowering the pile to enter the seabed soils, at first under its own weight until it rests on soil friction, followed by pumping out seawater from »

» inside the pile to enable it to penetrate to its full depth.

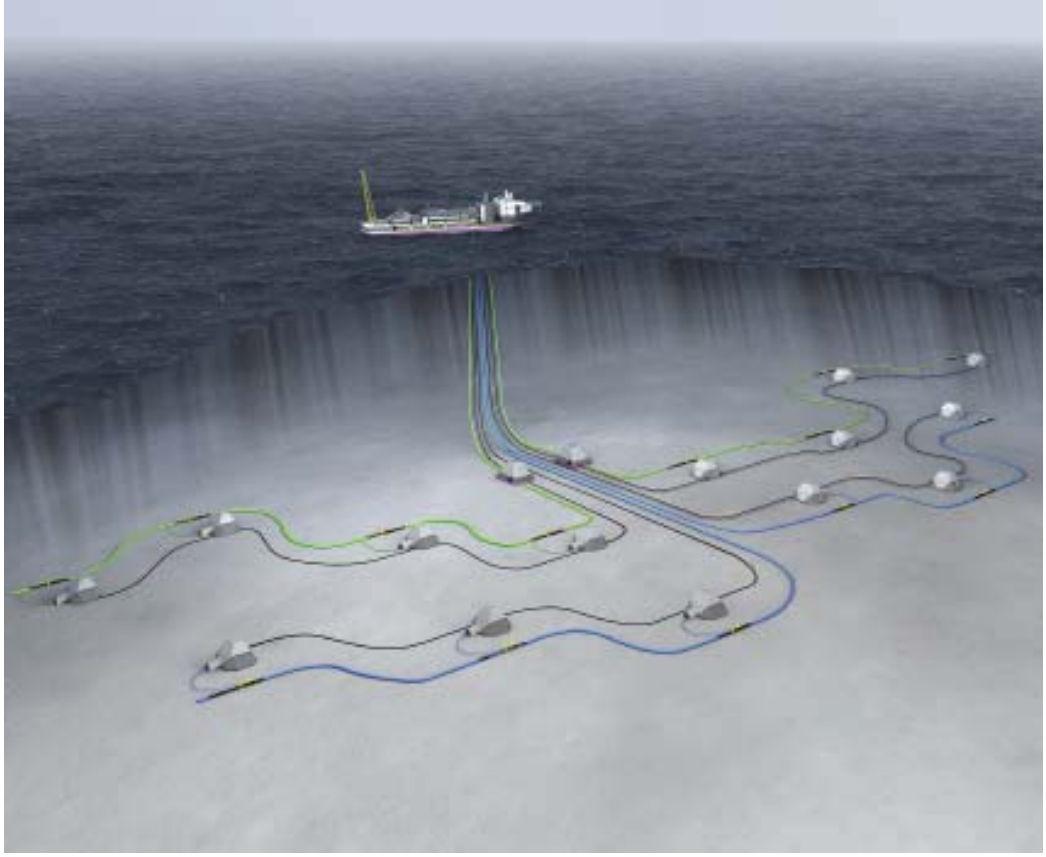
"A key feature of the Cap-X pile is that the drilling conductor is pre-installed in the pile," explains Kjell Einar Ellingsen, leading advisor in Statoil's subsea technology and operations team who is credited with the initial vision for the Cap-X concept. "The pile produces an extremely firm foundation in the seabed, and once the pile is set, drilling can begin through the conductor which is already inside the pile."

The conductor, 30 to 36 inches in diameter, reaches down into the seabed to around the same eight to 10 metres depth as the suction pile, and is therefore much shorter than a conventional conductor.

"Because the conductor is so short, it allows you to start to build an angle on the well path much earlier in the drilling operation," adds Ellingsen, "enabling the average and maximum drilling angles to be kept down during the transition to the horizontal section. This greatly reduces the risk in creating horizontal wells into shallow reservoirs, some of which in the Barents lie less than 200 meters below the seabed."

Suction piles are regularly employed in the offshore industry, frequently as seabed anchors in the mooring systems of floating vessels. Indeed, Statoil was involved with the early development of suction pile technology and in 2015 was acknowledged by the Offshore Energy Centre in Houston — along with NGI (Norwegian Geotechnical Institute) and Shell — for its pioneering work in the field, stretching back to the 1980s.

The company has specific experience of suction piles related to subsea wells, albeit in different form from the new Cap-X concept. Statoil has 58 subsea wells based on drilling through suction pile foundations, mainly in the North Sea. Most of these wells were drilled conventionally through "four slot template" structures, plus a few satellite wells. In these cases, the conductor and wellhead were initially separate from the template and were later cemented to the template via a tailpipe welded to the suction pile. Something more akin to Cap-X was installed by Statoil in 2004 in the Troll field involving a pre-installed conductor in a suction pile on a shallow gas observation well, now decommissioned.



CONNECTED: The design of Cap-X enables each well to be connected directly to a gathering flowline (green) or water injection line (blue) via jumpers integrated into the lines, without manifolds, enabling wells to be spaced optimally. Black lines are umbilicals. In this case, the two gathering lines feed into booster pumping stations, housed in the standardised structure on top of Cap-X suction piles.

"Although Statoil has this wide experience with suction piles, we wanted to develop a simpler and cheaper solution for a single well that can be deployed in most situations," says Ellingsen. "The suction pile gives us this. It provides a very strong foundation as all loads are transferred from it into the seabed. It takes the weight of the well, rather than relying on a longer cemented-in conductor as in a conventional well, allowing the conductor to be shorter. The pile is also strong enough to withstand subsea tie-in loads and lateral forces such as impact from trawling gear, and has the capacity to take the load of any blowout preventor stack during drilling, which permits a wide range of rigs to be employed and offers better wellhead integrity."

Controlling the envelope

Pre-installed and sitting on top of the suction pile is a steel frame for supporting the wellhead after drilling is completed, along with connecting valves and piping, plus protective end skirts made from glass reinforced plastic (GRP). Once the wellhead is in place, GRP hinged top hatches will be added to the structure, designed to be easily openable for intervention operations and "snag free" to allow fishing gear to pass freely over the well.

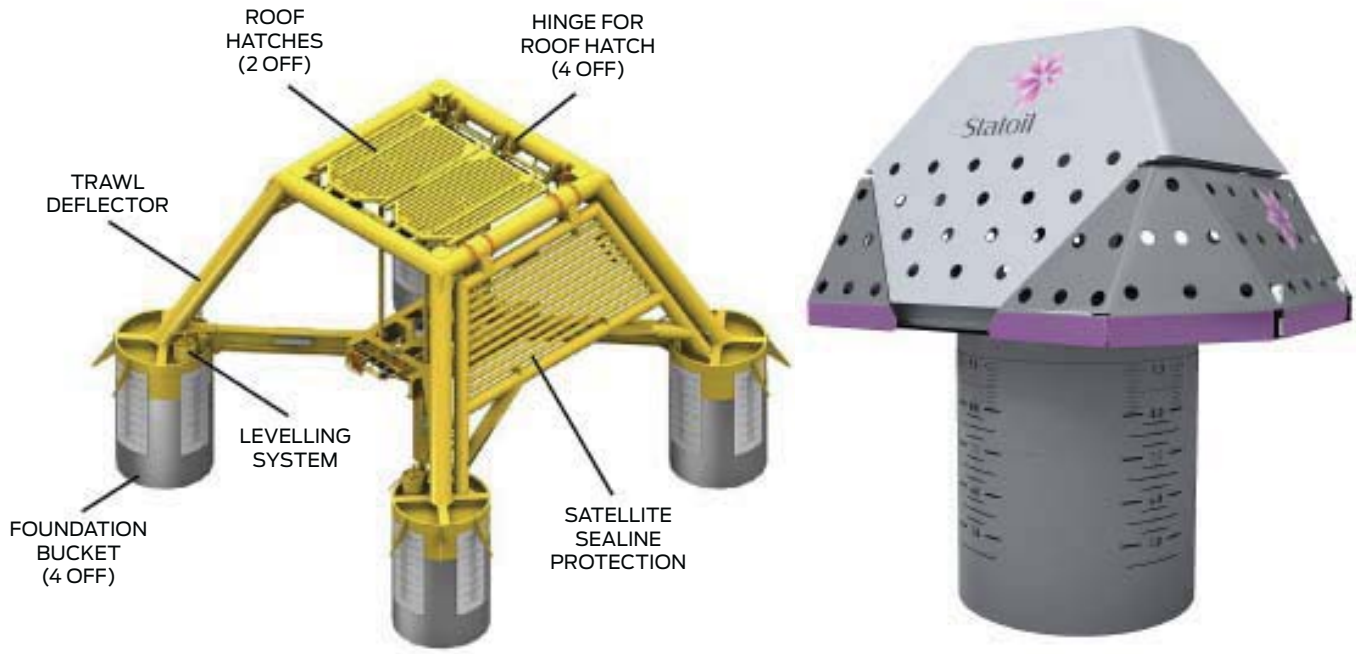
Each well is connected directly to a gathering flowline via a jumper integrated into the line, without manifolds, enabling optimum spacing of wells. While the standard Cap-X unit is envisaged to be for a single well, a dual well design will be an option, offering a very economic way to provide a second well slot.

This relatively simple arrangement for installing a single well can be replicated many times at suitable intervals above a shallow reservoir to allow cost-effective access to

Photo: Statoil

"We believe Cap-X can cut the overall cost of hardware, installation and drilling of a single well by up to 30%."

Bjorgulf Haukelidsaeter Eidesen, Statoil



SMALL FOOTPRINT: A conventional single satellite well template with four foundation buckets as deployed by Statoil measures 22 metres by 22 metres, stands 15 metres high overall, and weighs 165 tonnes, including roof hatches and sealine protection. By comparison, the single well Cap-X unit has an overall width of 9.8 metres and a height of 16 metres – equivalent to about one quarter of the conventional template's footprint area — and weighs 106 tonnes.

the reservoir through multiple horizontal wells, says Statoil, while also reducing drilling time and reducing risk.

"Compared with a conventional single-well template with four corner suction piles, we believe the Cap-X single well can cut the overall cost of hardware, installation and drilling by up to 30%," says Eidesen. "And if you take into account the large number of wells that will be required in Barents Sea fields, this amounts to very significant savings."

A typical Cap-X well structure would be almost 10 metres wide and 16 metres high, including the top hardware (see diagram above), and weigh around 106 tonnes — the substructure accounts for about 90% of the overall weight. When compared with a conventional single-well template with four foundation buckets, the footprint of the Cap-X structure is only one quarter of the size and weighs around one third less.

Such advantages provide further opportunities for both transportation of more Cap-X units onboard a single vessel, in theory four times as many units, plus the ability to install the units into the seabed using the vessel's crane — the smaller size and weight of Cap-X means less "boom out" distance for the crane, effectively giving it more lift capacity. Furthermore, using a marine vessel for installation reduces the amount of costly drilling rig time. Given the remote location of the Barents Sea and offshore distances to the fields of 300 to 400 kilometres, any development solution that helps reduce transportation logistics and the number of trips will be welcome.

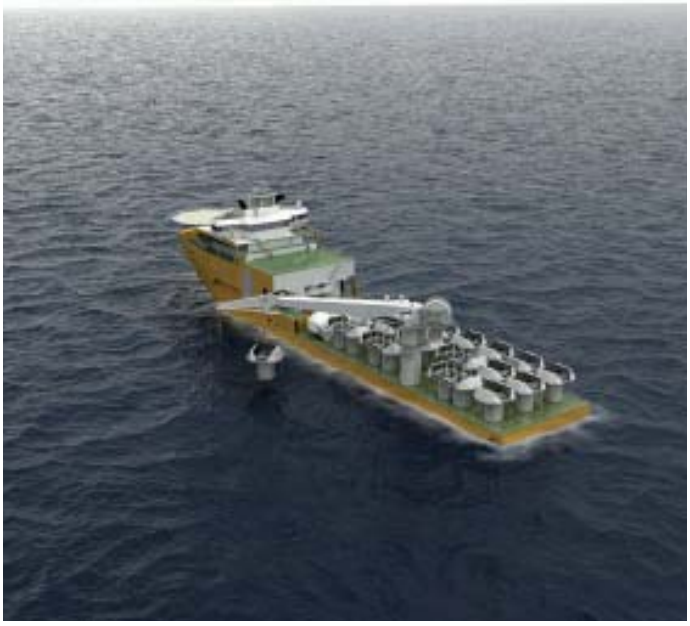
"What Cap-X does is give Statoil, as operator, control over an important hub — the well," adds Eidesen. "This hub interacts with many aspects of the development, for example transportation, installation, drilling and pipelines, so we are able to exert an influence over wider development operations through the advantages of Cap-X."

Throughout the cost evaluation programme, Statoil kept standardisation high on the agenda. The company has standardised some subsea elements in the past, for example the four-slot well template, which has been very successful, particularly in terms of the time needed to bring wells into operation relatively quickly. But for the Barents Sea, the company wanted to go further, to optimise both time and cost with a simpler standard approach.

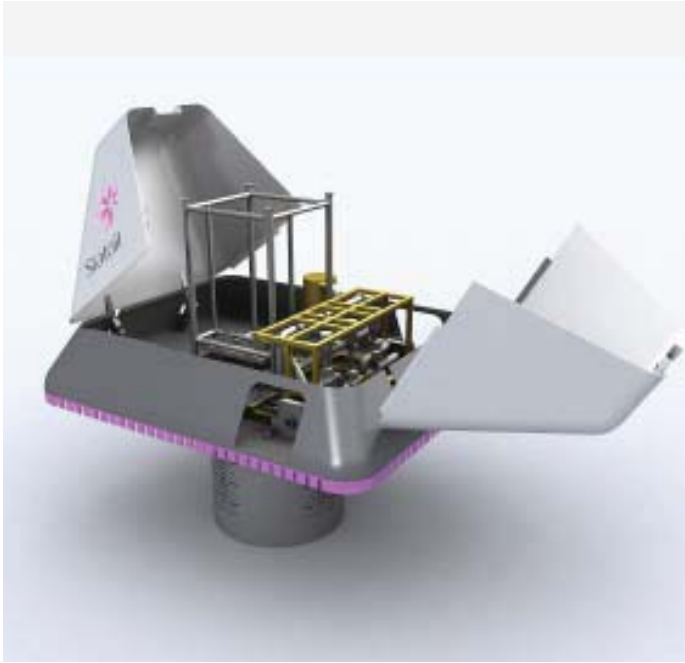
To this end, the driver was to develop a subsea interface that gives the operator "control of the envelope", the enclosed space into which everything must fit, be that a subsea wellhead from one of the main suppliers, or other types of equipment, such as subsea booster pumps, which are likely to be needed for Barents Sea applications.

Ellingsen likens this to a domestic kitchen, where all the different types of appliances from all manufacturers are built to fit into standard spaces. "Cap-X gives Statoil ownership of the main platform, a space where the industry can apply its solutions without necessarily changing any of its proprietary designs, and one which will promote more competition, bringing new suppliers into the arena. It gives us the chance to manoeuvre better, both technically and commercially."

Given the large number of subsea wells that will be required for the Barents Sea, perhaps up to 100 for some prospects, there is a likelihood of the scopes of work involved being too large for a single supplier to handle in a timely manner. Statoil believes Cap-X will provide an open platform that accommodates "mass production" from several suppliers in parallel, offering greater procurement flexibility and efficiency, and ultimately giving speedier delivery and installation times for achieving accelerated field development schedules. »



ON DECK: The smaller footprint and lower weight of Cap-X present advantages for transportation and allow a ship's crane to carry out the installation, reducing costly drilling rig time.



STANDARD ENVELOPE: The standard equipment envelope on top of the Cap-X suction pile provides industry with an open platform, not only for wellheads but also for other subsea equipment such as booster pumps.

The wider view

All design work on the Cap-X concept to date has been performed in-house by Statoil, including 3D modelling and structural and hydrodynamic analysis of operations such as transportation and lifting. As part of the standardisation approach, the equipment envelopes have been defined, for example for accepting wellheads — including even the largest of these — tie-ins and connectors, termination assemblies, hydraulic power supplies and others. According to Statoil, only detailed engineering remains to be done on the design. Having sought the input of leading fabricators, the company is confident that the concept is "fabrication friendly" and straightforward enough to be built locally in any region where Cap-X might be deployed, another potential cost-saving advantage.

Statoil is believed to have included the Cap-X concept in its recent applications for Barents Sea licences. If such an application were to come to fruition there, given the lead time required for exploration, appraisals and development approval, it could take five to seven years for Cap-X hardware to come into action on the seabed. But the company is optimistic that the concept may see live action before then, perhaps on a North Sea project as a subsea satellite well tie-back, perhaps in around 18 months from now.

Patent applications have been submitted covering several aspects of the Cap-X design concept, its application and operation. Among these is a method for ensuring the suction pile is installed "vertically" within very tight tolerances into the seabed, an important factor for enabling connection of the blowout preventor and drilling through the conductor, and also for the subsequent interconnection of other equipment on top of the well.

"For a conventional template with four foundation buckets, you can level each one individually using the suction pumps to give almost perfect levelling of the overall structure," explains Eidesen. "For a single suction pile such as on Cap-X, we will use a different approach — but with patents pending we are not able to say more at this stage. Suffice it to say we have a lot of experience with installing suction piles and Statoil's technical group that has developed the solution includes some of the people that originally started out developing suction anchors."

Should a particular seabed location be unsuitable for a suction pile — though not likely in the Barents Sea where the seabed tends to be soft clay — then a conventional conductor could be used to support the new-look Cap-X wellhead template, retaining the advantages of the standardised envelope it provides.

This raises the possibility that Cap-X could see wider use in subsea developments around the world. While the origins for Cap-X lie in Statoil's quest to find more commercially attractive solutions for shallow reservoirs in the Barents Sea, the nature of the concept does not limit it to any one region or type of subsea development, whether it be for shallow or deep reservoirs, or shallow or deep water.

"We see the potential for Cap-X to be a robust solution for many different applications," enthuses Ramberg. "There are the obvious new field developments, but it could also serve as a simple satellite for brownfield locations, or in enhanced oil recovery operations, or for tapping into marginal resources — the list is long."

So if Cap-X is a relatively simple, lower cost solution that offers so many advantages, how come it was not thought of before now?

"Because we have not been faced by the same set of offshore conditions and economics before," Ramberg concludes.

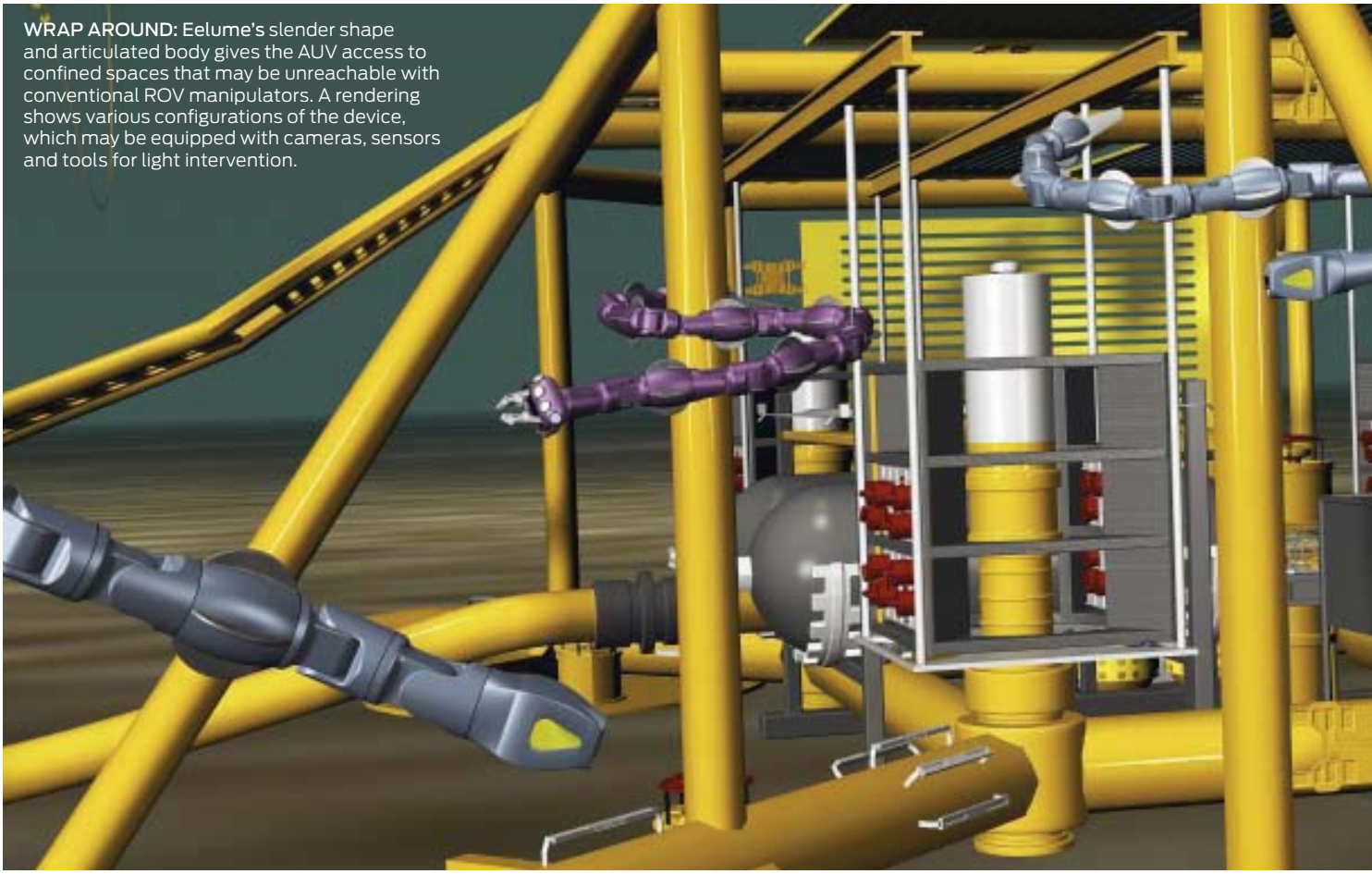
Necessity truly is the mother of invention.

Photo: Ole Jorgen Bratland/Statoil

"Cap-X will greatly reduce the risk in creating horizontal wells into shallow reservoirs in the Barents Sea."

Kjell Einar Ellingsen, Statoil

•• *Cap-X™ is a trademark of Statoil*



WRAP AROUND: Eelume's slender shape and articulated body gives the AUV access to confined spaces that may be unreachable with conventional ROV manipulators. A rendering shows various configurations of the device, which may be equipped with cameras, sensors and tools for light intervention.

Images: Eelume

See snake

Autonomous underwater vehicle design takes a serpentine turn with a promising new inspection and intervention tool, writes **Russell McCulley.**

The subsea industry cannot seem to resist the temptation to use references from nature — swimmers, fish, flying eyeballs — to describe remotely operated vehicles (ROVs) and their free-floating cousins, autonomous underwater vehicles (AUVs).

But scientists in Norway are taking this biomorphic tendency to a new level with Eelume, a seafloor-dwelling inspection and light maintenance AUV concept that uses snake robotics technology to swim into confined spaces and difficult-to-access areas of subsea infrastructure.

In this case, "swimmer" is a fairly accurate description — the slender robot's articulated body moves through the water in a sinuous motion, the repetitive movement, enhanced by thrusters, providing propulsion in a manner similar to the robot's animal namesake. The motion, coupled with the device's snakelike "head" and manipulator "jaw", give the impression of a sci-fi sea serpent.

Eelume's snake-like qualities command attention, but the design is grounded in more practical matters, says Kristin Ytterstad Pettersen, a professor of robotics at Norwegian University of Science & Technology (NTNU) and chief executive of Eelume, the company spun off from the NTNU research programme.

"The idea comes from the research we have done on snake robots for the last decade. We are very interested in these biologically inspired robots," she says. "Snake robots move very nicely."

Snake robotics are currently used in land-based applications such as search and rescue operations, and have proven effective for exploring hazardous environments, rugged terrain and confined spaces. Subsea, however, marks a new frontier.

"On land, these robots are able to move on very rough terrain and in narrow areas," Pettersen says. "They are very interesting compared to legged or wheeled robots."

The advantages are even greater in water, where movement is less restricted. "Biological snakes and eels are very good swimmers," she notes.

The Eelume research and development programme is a collaboration of NTNU academics, marine robotics experts at Kongsberg Maritime, and Statoil, which is providing access to offshore installations for testing and qualification.

The robots, customised to an operator's needs and specific field conditions, will be permanently installed on the seabed. Between

SMOOTH MOVES: The Eelume research team developed a concept demonstrator robot, pictured during tank tests in early 2015, to study the motion dynamics of swimming snake robots. The tests successfully demonstrated both remote control using a joystick as well as autonomous motion, such as following predefined trajectories, based on advanced control algorithms.

CLOSE-UP: The Eelume prototype featured lights and a hi-resolution video camera. The robot, essentially a free-swimming manipulator arm, is designed to accommodate maintenance and light intervention tooling.

inspections and interventions, they will return to a docking skid to recharge batteries and transfer data. The idea is to create an alternative to the costly practice of using ROVs and support vessels to perform common tasks such as inspection, cleaning and adjusting valves and chokes.

In this, Eelume joins a small but growing pool of so-called "hybrid" vehicles that will combine a high degree of autonomy with some capacity to perform both scheduled and on-demand tasks. Other entries include BG Group's FlatFish (Upstream Technology 1/2016) and the Autonomous Inspection Vehicle (AIV) from Subsea 7.

Self-going janitor

Eelume's unusual shape sets it apart from these examples, which resemble traditional ROVs minus the tether.

"We realised in the subsea industry there was a growing need for cost reduction, of course," Pettersen says. "And as part of that there was a need for an inspection AUV, and preferably an intervention AUV. We saw that the way most people were going about that was to make ROVs smaller and smaller in order to make them inspection AUVs that could get into confined spaces."

Scaling down an ROV, however, means a proportional reduction in the size and capability of the manipulator arm it must support.

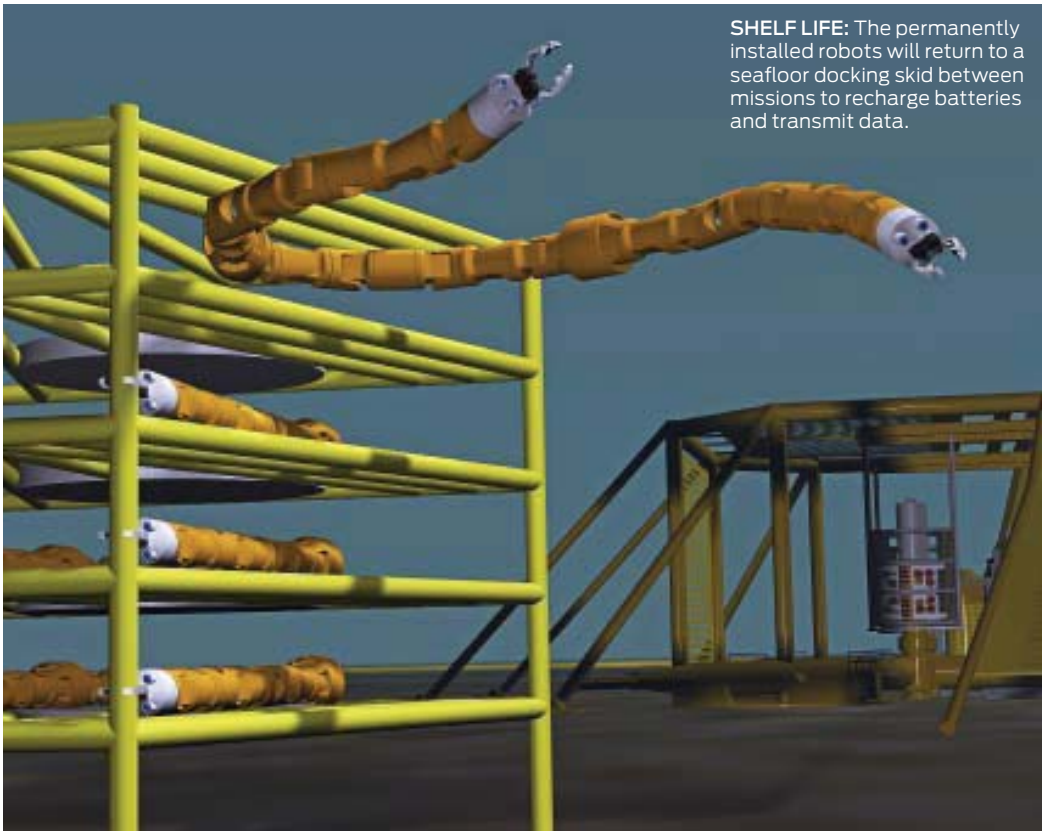
"That's when we realised that, instead of adapting the work-class ROV, we looked at it from another angle and said, why can't the robot manipulator arms swim by themselves? Why do they need this ROV body to bring them where the operation is performed?"

NTNU and the Norwegian research organisation SINTEF have conducted research on snake robotics for about 10 years. Much of that research has focused on control theory — Pettersen's speciality — which involves working out »

Photo: Ronny Danielsen

"This technology could help bring down the size of subsea equipment considerably, and thus the cost."

Kristin Ytterstad Pettersen, NTNU



SHELF LIFE: The permanently installed robots will return to a seafloor docking skid between missions to recharge batteries and transmit data.

"It's a beautiful technology"

Geir Espen Schmidt, Kongsberg Maritime

» the proper mathematical and software algorithms that control the motors in a robot and make it move in a desired way.

For Eelume, that means programming the articulated joints so that the robot mimics the oscillatory movements of a snake or eel. Tank tests have demonstrated that the Eelume robot can "swim" using a snake's sinuous motion alone, but thrusters provide more efficient propulsion, Pettersen says. Thrusters will also provide a counterbalancing force during intervention activities.

"In our research we can show that because of the hydrodynamic properties of the fluid and the snake robot, which is a long structure, when you do these kinds of oscillations, it moves the snake robot forward. You don't need the thrusters to move. But it's more efficient when you add the thrusters."

The snake-like form allows the robot to access confined spaces beyond the reach of manipulator arms attached to an ROV-style propulsion and power unit.

"With this slender vehicle, the vehicle itself will be a manipulator," explains Geir Espen Schmidt, vice president marine robotics at Kongsberg Maritime. "It's a beautiful technology."

Eelume could "remove the constraints" of a bulky ROV, he says, as well as the need to mobilise a support vessel for routine inspection and maintenance.

"We want to offer subsea resident capability, continuous inspection of subsea production equipment, and a way to alert (operators) if there are issues."

Eelume will function as "a flexible robot acting as a self-going janitor on the seabed," as Statoil chief technology officer Elisabeth Birkeland Kvalheim has described it — a "good example of how new technology and innovation contributes to cost reduction".

Cost conscious

The operational cost savings could be significant. But the incorporation of small autonomous inspection and maintenance vehicles in subsea field design could have an equally profound effect on development and installation costs, Pettersen points out.

"This technology could help bring down the size of subsea equipment considerably, and thus the cost," she says. "Now, (subsea) equipment is designed to accommodate work-class ROVs. Subsea installations cost eight times as much as a similar installation on land and are 12 times the size. They are much larger, and that's because they are designed for the limitations of the ROVs that we have today. They are big in order to give them access.

"These smaller, slender AUVs that are able to access really narrow areas could have an impact on reducing the equipment installation costs. They would reduce costs on existing installations, and could allow new installations to be designed smaller and more cost-efficient."

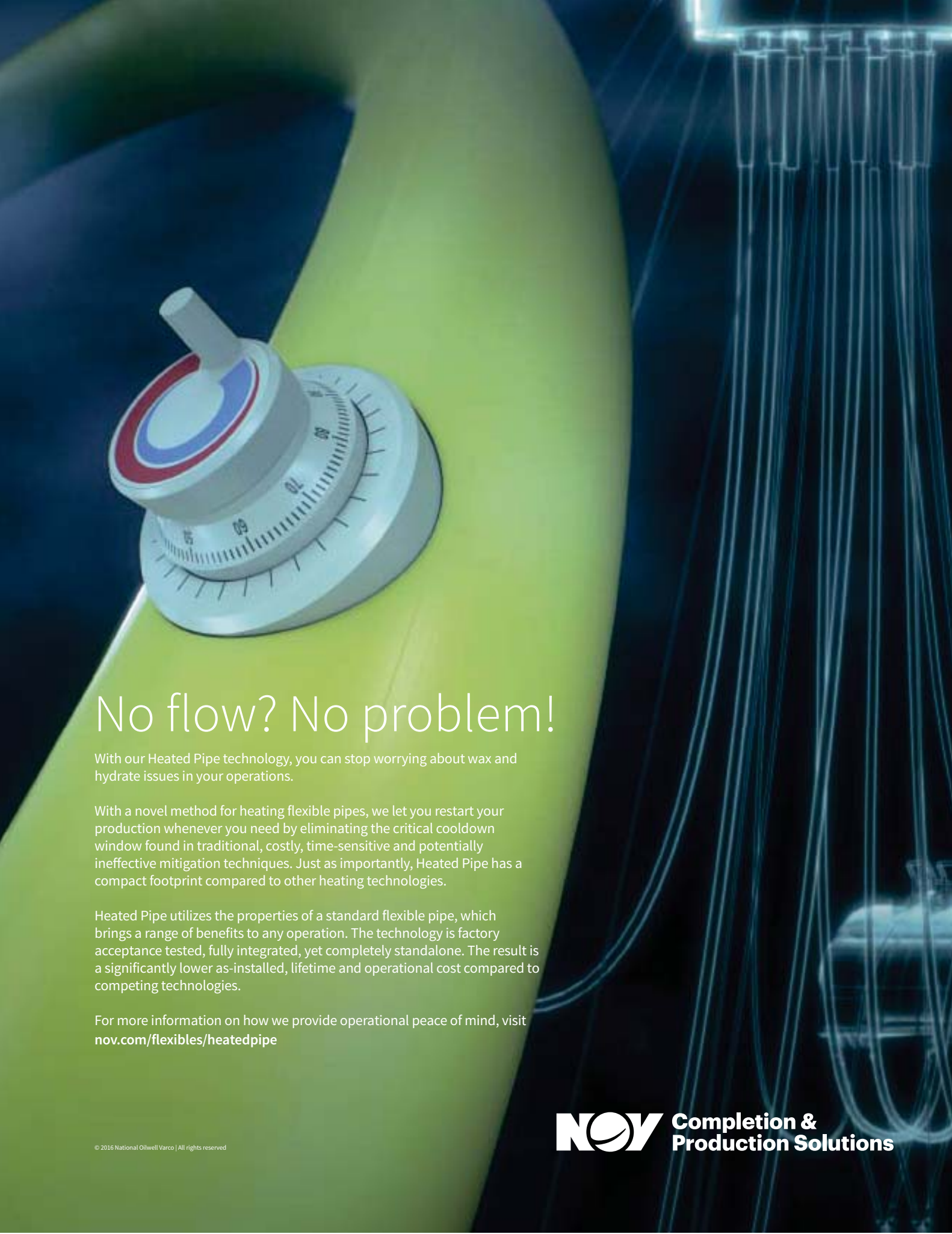
Eelume's motion algorithms were tested in the laboratory using a prototype powered by a control cable. The finished robot, however, will operate with battery power, eliminating the vexing challenge of tether management. The 1.7-metre long test model measured about 80 millimetres in diameter, but Eelume will be scalable depending on how it will be used and at what depth. Scaling it up or down "is just an engineering question", Pettersen says.

Scientists are now working toward a pilot programme off Norway perhaps as early as next year. The offshore prototype will be equipped with thrusters and a camera — Pettersen says it is too early to say what type of sensors or manipulators, if any, will be installed on the prototype model.

She has high praise for Eelume's collaborators — Kongsberg "are world leaders in AUV technology, and experienced with AUV technology development within marine robotics. That is very valuable for us," she says.

"Statoil, of course, is providing access to real installations for testing and qualifying the technology" as well as input on industry needs.

Ageing subsea infrastructure, increasingly complex developments and constant pressure to rein in costs are driving interest in autonomous inspection and maintenance technologies, says Schmidt. "It's not technology for technology's sake. It's technology that addresses the needs of operators. That's why it's so important that Statoil is part of this project."



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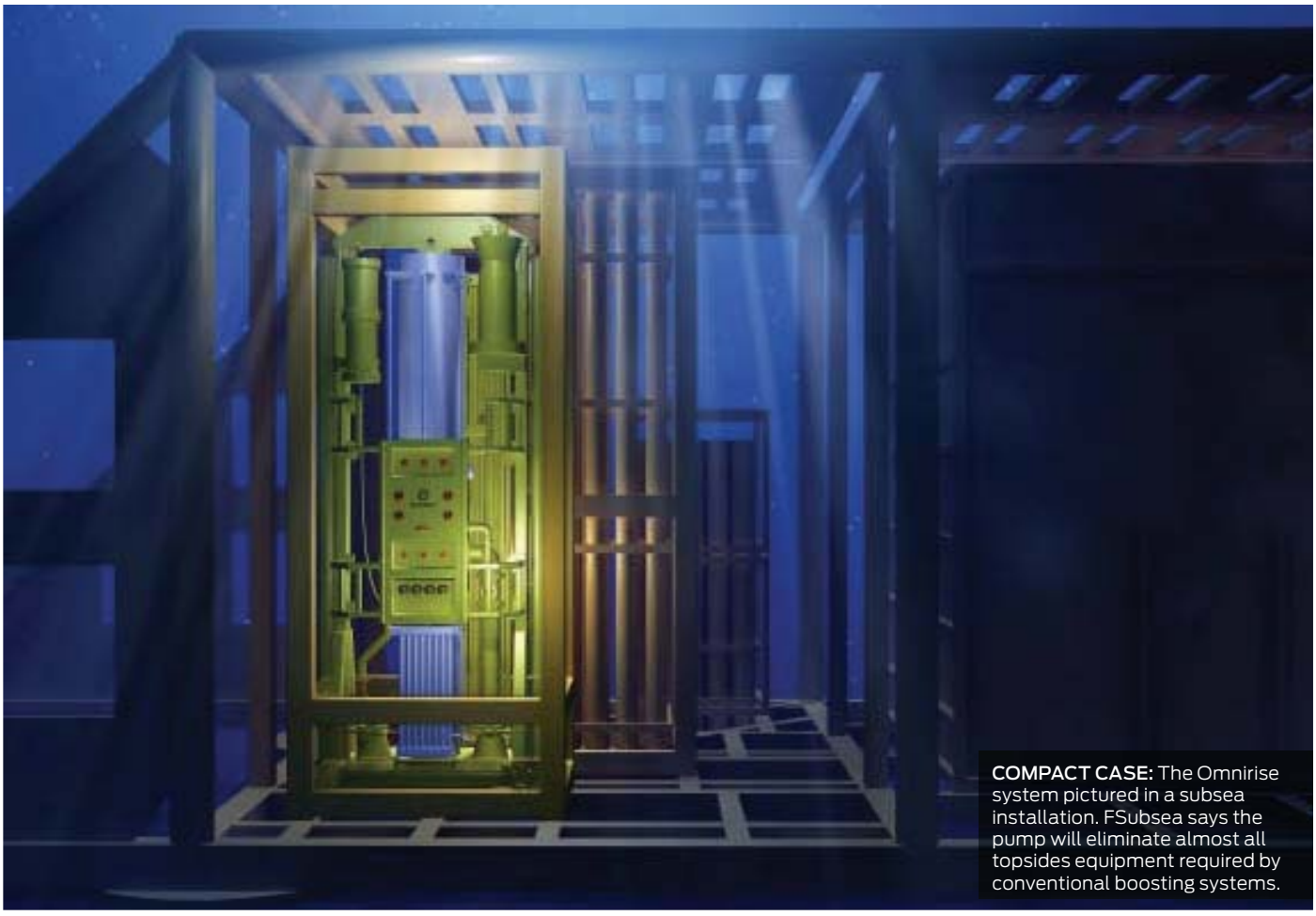


COMPACT CASE: The Omnirise system pictured in a subsea installation. FSubsea says the pump will eliminate almost all topsides equipment required by conventional boosting systems.

Removing barriers to subsea boosting

A streamlined subsea pump system being developed by Norway's FSubsea caters to the industry's need to deliver increased recovery at lower cost from existing fields, writes Steve Marshall.

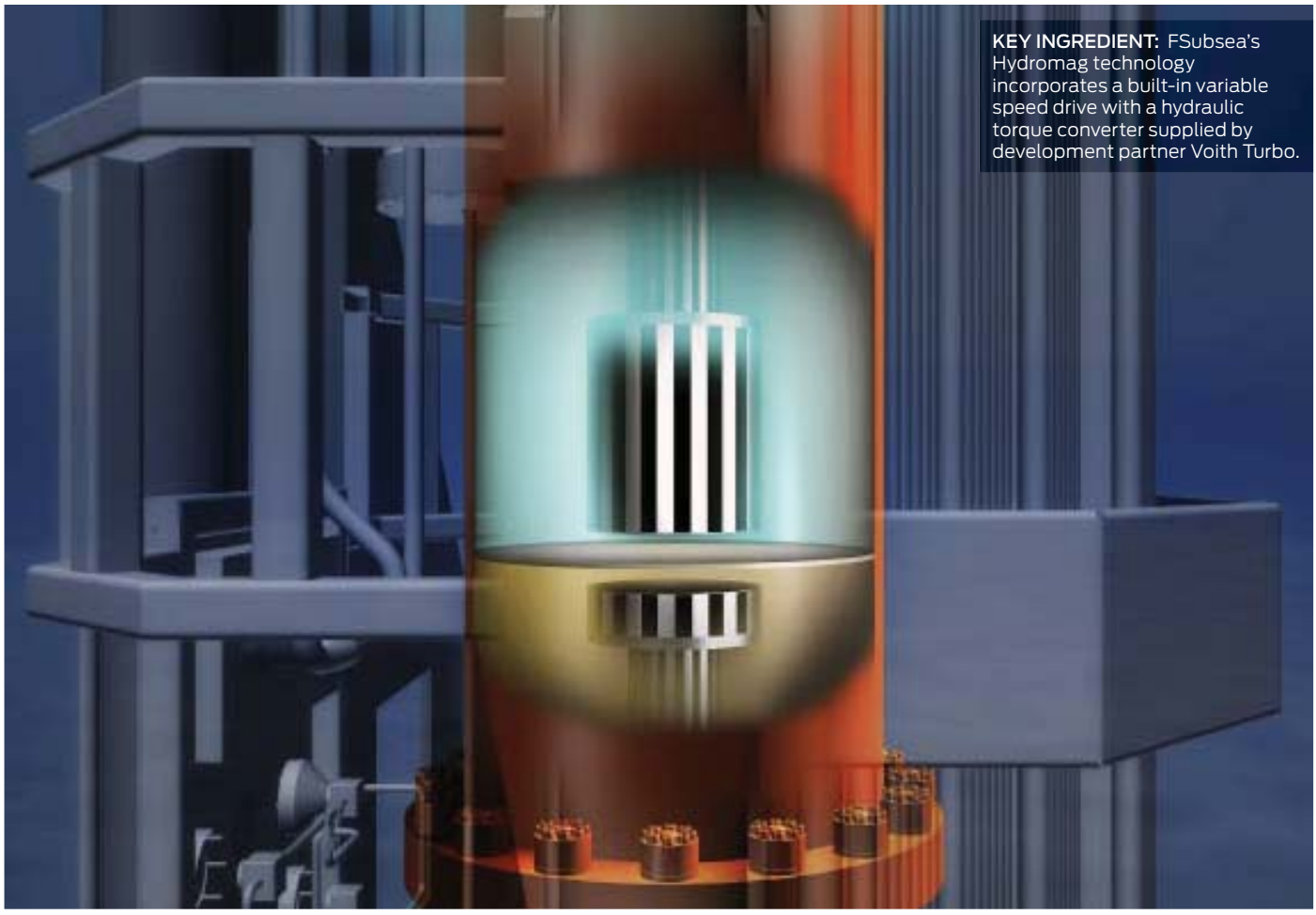
Subsea boosting is seen as an effective means of increasing recovery while also extending the lives of existing fields. But prohibitive costs, combined with the bulk and complexity of topsides equipment for underwater pumps, have meant it remains a rare luxury for most operators.

Of around 1500 subsea fields worldwide, only about 25 fields with 5000 active wells have subsea pumps installed to boost recovery, including Total's Girassol and Pazflor off Angola, and Chevron's Jack-St Malo in the Gulf of Mexico, based on figures from Oslo-based research firm Rystad Energy.

This remains a paradox, however, given there is a "tremendous business case" for operators to boost recovery from existing wells in the present low oil price environment to lift revenue while avoiding exploration-related seismic and drilling costs, according to Fuglesangs Subsea (FSubsea) chief executive Alexander Fuglesang.

A typical deepwater field has a recovery rate of around 30%. Subsea boosting can increase this by a factor of 10% to 30%. Chevron estimates the use of such pumps at Jack-St Malo will yield additional output of between 50 million and 150 million barrels — or the size of a small oilfield.

Fuglesang estimates expenditure of $50 million on a pump system to deliver an additional 20 million barrels of oil would have payback in less



KEY INGREDIENT: FSubsea's Hydromag technology incorporates a built-in variable speed drive with a hydraulic torque converter supplied by development partner Voith Turbo.

than a year, given there would be instantaneous cash flow in the range of 10% to 30%, even at an oil price of $30 to $40 a barrel.

However, he points to the major obstacles in installing current subsea pump systems, which require complex topsides equipment weighing as much as 600 tonnes — including hydraulic power units (HPUs), variable speed drives, control systems and steel structures — as well as myriad umbilicals connected to pump manifolds on the seabed.

Aside from the issue of finding space on tightly packed platforms, retrofitting such systems causes major disruption to operations as it requires a costly production shutdown.

Smaller footprint

Morgan Stanley has estimated the average cost of a conventional pump system at $100 million, of which installation accounts for $30 million. These systems also incur substantial operating costs related to marine transport of personnel for topsides and subsea maintenance over a field's lifetime.

PARED DOWN: The subsea pumping system requires a single standardised power umbilical.

"This is the problem we are trying to attack. We are systematically trying to take away the barriers to installation of subsea pumps with a simpler and more streamlined system that has a much smaller topsides footprint, ease of installation, zero to very low maintenance and significantly lower capital expenditure," Fuglesang says.

The Omnirise pump system being developed by the small Oslo-based company using its Hydromag coupling and drive unit can reduce the topsides requirement by between 200 and 600 tonnes, thus in some cases eliminating it altogether, he claims.

It is being touted by FSubsea as a "topsides-less" modular system that can function almost autonomously on the seabed, requiring only a single power umbilical from a small unit installed topsides, or onshore if the step-out distance is less than 15 kilometres.

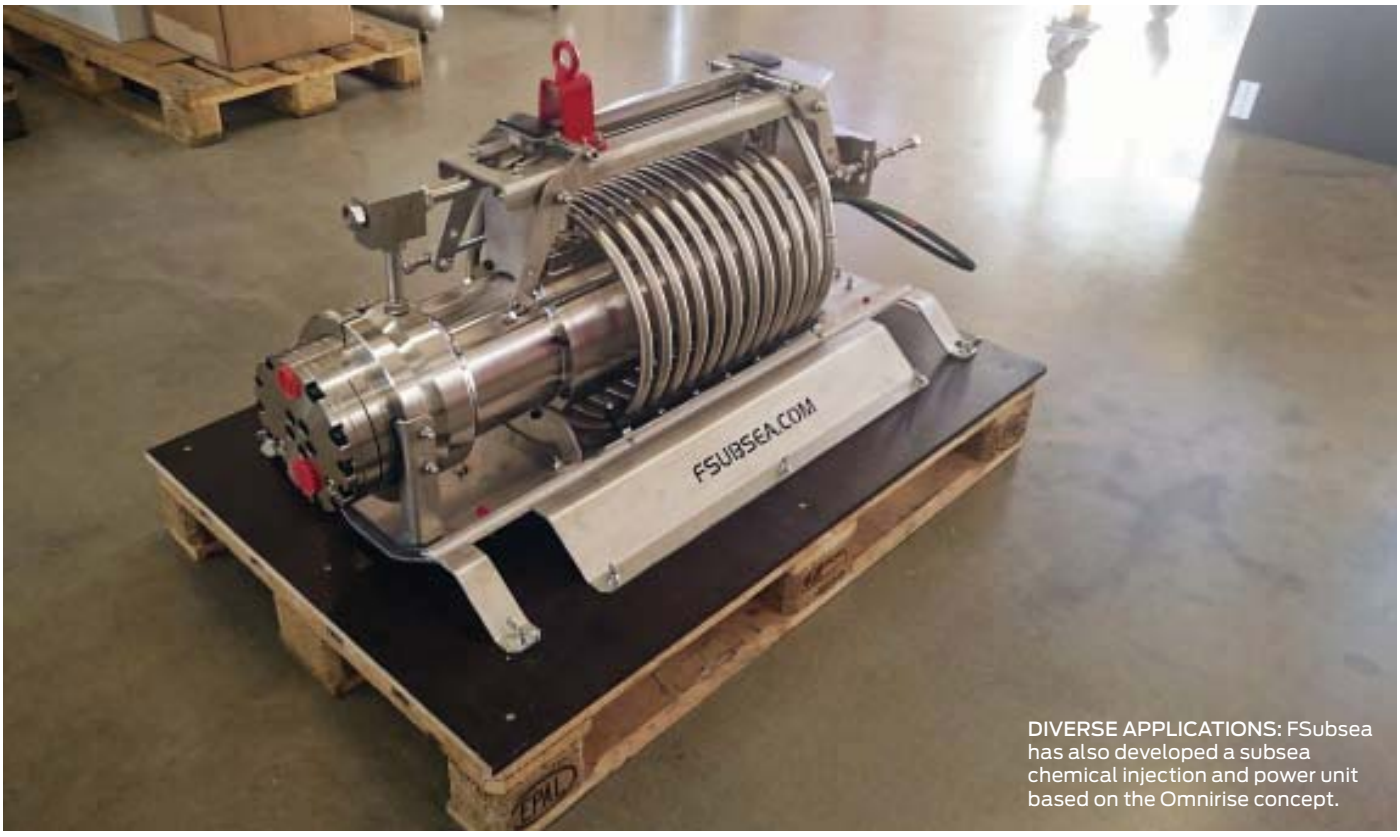
Current systems require multiple umbilicals, including those used to transport barrier fluids to lubricate pump seals. These must be regulated by an intricate system of valve controls in HPUs installed topsides to manage pressure in the seal phase and ensure fluid cleanliness.

As well as increasing operational expenditure, such systems are vulnerable to leakage, with seal issues the primary reason for the large number of subsea pump failures, according to Fuglesang.

A case in point is the leak late last year of 1500 litres of chemicals used for lubrication and cooling of a pair of subsea compressor stations only months after they were installed at Statoil's Gullfaks South field off Norway, resulting in them being put out of action and taken to land for repairs.

Fuglesang contends: "By simplifying the system, we are also making it more robust."

The Hydromag incorporates a built-in variable speed drive with a hydraulic torque converter supplied by development partner Voith Turbo, which means the pressure-compensated electric »



DIVERSE APPLICATIONS: FSubsea has also developed a subsea chemical injection and power unit based on the Omnirise concept.

» motor can spin at a low speed of around 3600rpm, while the one-megawatt variable high-speed pump can run at up to 7200rpm — even faster than the 6000rpm for other pumps currently being developed.

The so-called mechanical seal between the motor and pump, which is typically lubricated with barrier fluids, is replaced in the Hydromag with a seal-less magnetic coupling that eliminates the need for barrier fluids, and thus the associated topsides equipment and umbilicals.

This coupling creates a hermetic barrier to ensure process liquids in the pump are sealed off to maintain cleanliness of other fluids and also reduce significant frictional, or drag, losses of energy that occur in rotating machinery.

Cost saver

There are environmental benefits in terms of a reduced risk of leakage subsea and lower carbon dioxide emissions due to the need for less topsides equipment, which in turn cuts the requirement for electricity generation using steam turbines as well as pollutive transport of personnel by vessel and helicopter, according to Fuglesang.

Furthermore, the smaller size of the streamlined Omnirise pump means thinner steel casing is required, compared with thicker housing on existing multi-pump manifolds, due to lower ambient pressure.

Ultimately, of course, what counts for operators in these lean times of cost-cutting due to low oil prices is the impact of such technology in terms of dollars and cents. FSubsea estimates the Omnirise system represents a cost saving of around 70% compared with conventional subsea pump installations.

Under a scenario with three subsea pumps, a conventional system entailing heavyweight topsides hardware and multiple umbilicals — including a dedicated power cable for each pump — would cost a total of $115 million including integration and installation, according to a company estimate.

By comparison, FSubsea says installation of the Omnirise system, with minimal topsides hardware and only a single power umbilical for several pumps, would cost about $40 million including integration and installation, representing a capital expenditure saving of $75 million. A key factor in the costs picture for the FSubsea pump is standardisation and reusability of the modular Hydromag technology, which means it can be manufactured at scale for universal

Photo: Steve Marshall

"We are systematically trying to take away the barriers to installation of subsea pumps with a simpler and more streamlined system."

Alexander Fuglesang, FSubsea

application across multiple fields.

"The big cost saving comes when you can reuse what you already have and not have overlapping standards and specifications as we have today," Fuglesang says.

Reusability of the standardised Hydromag hardware that makes up two-thirds of the pump module — meaning it does not have to be redesigned for each application — leads to significant cost savings, as economies of scale can be achieved from mass production of the units, he explains.

"Costs can really be driven down once you pass a threshold of manufacturing 10 to 20 similar units. At 150 to 200 units, it becomes even more impressive and a whole other game — more like the costs you see in the car industry."

This would also apply to the reuse of a single standardised power umbilical, avoiding time and money spent on engineering, testing and verification of bespoke umbilicals developed for each project.

"Everyone is wasting hours from the iron ore or copper mine to the manufacturer, but we want to simplify the whole value chain. We can scale this game to make it much cheaper," Fuglesang says.

Standard solutions

The use of subsea pumps typically entails thousands of man hours spent on engineering and design work for bespoke installations on individual projects that require integration of multiple components from different vendors.

Fuglesang points out engineering hours account for a major part of capital expenditure for such systems, while there is also "huge uncertainty" on equipment integration due to the compatibility of components in relation to field issues such as water depth and flow assurance.

Big project integrators such as Aker Solutions and FMC Technologies have their own product specifications, and a further challenge is compliance with myriad standards for such subsea hardware dictated by major standards agencies and oil companies, he says.

However, operators have recently been more open to sharing specifications with other industry players as they realise there is a potential cost benefit, he claims. FSubsea "aims to be at the forefront in developing standardised subsea solutions available from a catalogue".

FSubsea is now targeting brownfield applications of the Omnirise pump in the UK North Sea, tie-backs to existing fields in the Norwegian sector and greenfield installations in the Barents Sea, West Africa and South-East Asia. Another possible application for the pump is on topsides facilities such as unmanned platforms.

The developer has concrete expressions of interest from operators working in the Norwegian sector of the Barents, while it is also discussing separate projects off West Africa with a pair of supermajors. FSubsea is also in critical talks with project integrators considering the system for use alongside their current product offering, which would be a door-opener in this market.

Operators are increasingly looking to exploit fields using subsea infrastructure to eliminate the cost of topside facilities, with Statoil set to save a reported $1.9 billion on its Snorre 2040 redevelopment project off Norway by adopting a subsea solution rather than building a new platform.

Pumps are an integral element in a subsea system, and Fuglesang sees the market as ripe for his company's cost-saving technology, which could also be used on a so-called subsea factory for full processing and production on the seabed.

As well as "getting more for less from existing fields", he believes FSubsea's system facilitates longer step-out distances in remote, harsh-environment areas such as the Arctic Barents, and therefore is "opening the door to fields that would otherwise not be developed". U

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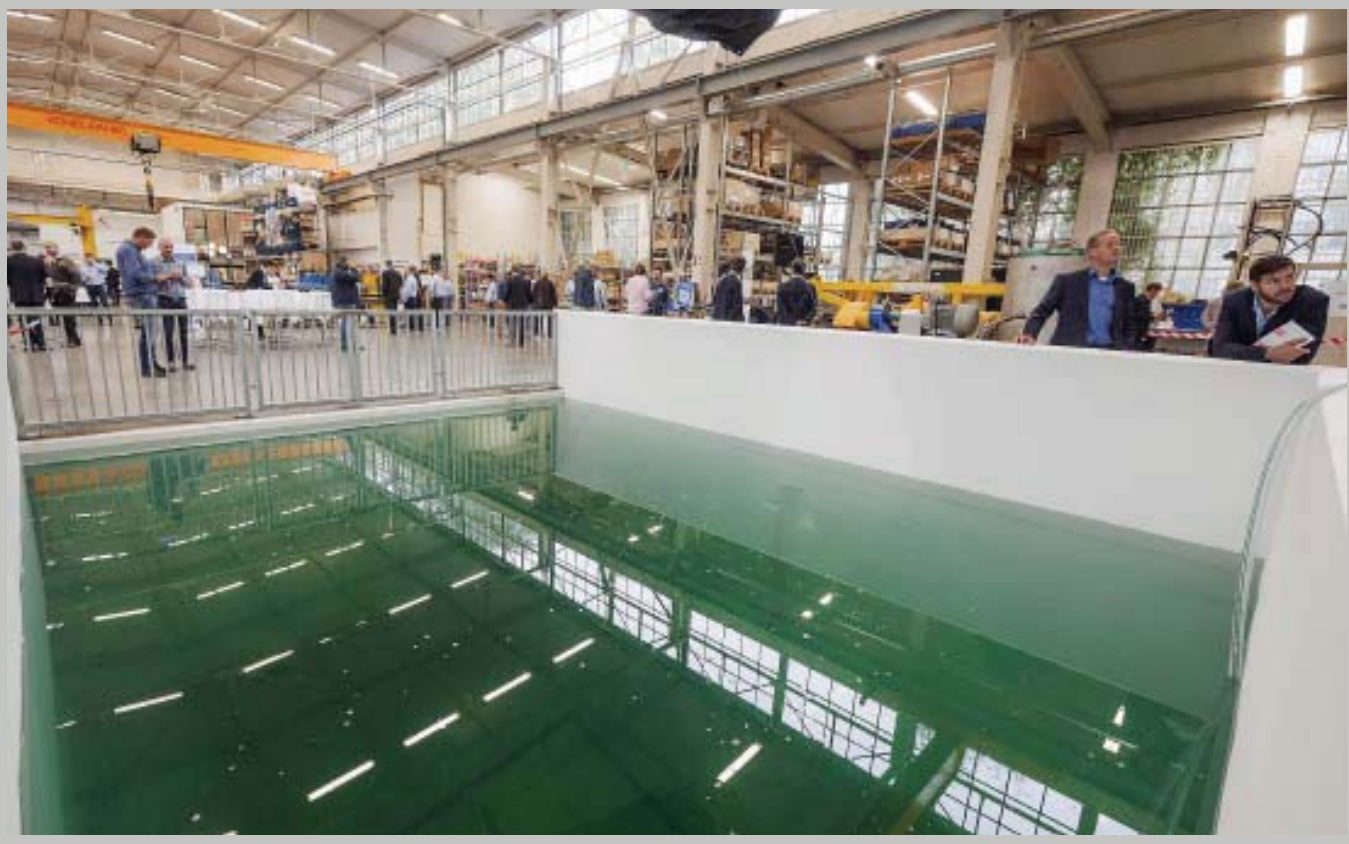

Images: FSubsea

NEW DIGS: Employees and customers gather around the test tank at the opening of FSubsea's Oslo facilities in September 2015.

Small player draws big backers for subsea boosting

Fuglesangs Subsea (FSubsea) has recently signed key pacts with industry partners to accelerate development of the Omnirise system that has been born out of a 10-year research and development effort, *writes Steve Marshall*.

The project recently received a financial boost through a tie-up with National Oilwell Varco and Innovation Norway, bringing total funding to Nkr50 million ($6.1 million) from partners for development of the pump's core Hydromag technology.

Furthermore, UK player Hayward Tyler has agreed to supply a fully qualified subsea motor as part of the qualification process for the technology prior to offshore testing, while Germany's Voith Turbo is providing the torque converter for the Omnirise pump's hydrodynamic variable speed drive.

FSubsea already has 28 subsea pumps operating in a range of deep-sea applications including dredging, trenching, slurry handling and drilling mud, based on its Searise and Mudrise systems.

In 2013, FSubsea was spun out of 100-year-old family-owned company Fuglesangs, which has worked with pumping and sealing applications in the mining, process and other sectors, to focus solely on subsea pumps.

"The parent company started the development of autonomous seabed pump technology 10 years ago. I subsequently saw the game-changing potential of magnetic couplings, resulting in development of a full-scale prototype pump to commercialise the concept, with a first delivery in 2013," says FSubsea chief executive Alexander Fuglesang.

The pump with magnetic coupling directly spawned the somewhat larger Hydromag technology to be used in FSubsea's largest and core range of Omnirise ECM (electric centrifugal multistage) subsea boosting pumps.

The developer, which presently employs only 10 staff but expects to expand over the next few years, has already qualified the world's first subsea seal-less pump with magnetic coupling in an oceanic test, together with four oil majors.

FSubsea is also on track to deliver the world's first subsea well intervention and chemical injection pump based on the Omnirise patent after recent qualification testing, with other applications for the technology including water injection, condensate transport and separation re-injection.

The company aims to qualify the Hydromag technology in the first quarter of 2018, ready to supply a single-phase pump package to a prospective client later the same year, with a multi-phase system likely to be ready in 2019. U

SUBSEA LIFT: A rendering of FSubsea's Omnirise ECM subsea booster with integrated variable speed drive and magnetic coupling.

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Image: Trelleborg

Polymers claiming space in deep water

Subsea engineers are finding more applications for non-metallic components, and manufacturers are queuing up for a share of the market, writes Steve Sasanow.

There is a famous scene at the beginning of the 1970's film classic The Graduate when a family friend of the eponymous lead character takes him aside and says, "I just want to say one word to you. Just one word...Plastics. There's a great future in plastics."

There is no doubt that there was and is a great future in plastics — or maybe more appropriately, non-metallic materials. There are those in the chemical process industries who do not want their products called plastics. How about polymers? Or maybe one of the many composite formulations, such as fibre and glass reinforced plastics? Take your pick, but any of them will provide a variety of industrial solutions.

Probably one of the biggest successes for non-metallics has been in the automotive industry. The removal of large amounts of metallic elements — much of them the dazzling chrome trim —made modern cars significantly lighter than their predecessors, resulting in greater fuel efficiency even before engineers began to tinker with the engine.

In the subsea arena, weight reduction can, in fact, be addressed in two ways — make the elements lighter, or support the weight using buoyancy. Two of the traditional applications for buoyancy offshore were drilling risers and remotely operated vehicles (ROVs).

Then along came Total's Girassol project, off Angola, at the beginning of the century. The decision to employ a freestanding riser system, the first of its type in that configuration, required a package that provided both insulation and weight support, and sent the development

FIRST RUN: Trelleborg and Landing Strings Solutions collaborated on the industry's first landing string buoyancy weight reduction system, deployed earlier this year at an Anadarko project in the Gulf of Mexico. Diamond Offshore's drillship *Ocean BlackHawk* performed the operation in 1800 metres of water.

Image: Balmoral

COMBINATION: Balmoral Offshore Engineering devised a method to deliver both buoyancy and insulation for the freestanding riser system at Total's Girassol development.

team off to find a supplier that could provide such a product. This precipitated a fierce competition between several companies, which was eventually won by Balmoral Offshore Engineering, and created a whole new market as this concept began to be used more widely.

Record set

With weight reduction firmly in mind, a very recent development has the subsea industry abuzz. As long as six years ago, Louisiana-based ExPert E&P Solutions, a company where the main activity was the repair and maintenance of drilling risers, perceived a need in the completions market for a buoyant landing string.

This is seen as game-changing technology. By reducing the weight of the landing string, casing string installation could be accelerated with the resulting reduction in rig time and cost savings. One operator told ExPert E&P Solutions that it saw the potential to save $40 million per well, and that by using this new system in a campaign, it could "drill three wells and get the fourth one for free". It also would allow older rigs to handle very heavy casing strings.

While ExPert E&P Solutions was designing the landing string — working through spin-off company Landing Strings Solutions — it went to Trelleborg Offshore to come up with what would be a technically challenging buoyancy package. The buoyancy not only had to withstand the maximum pressures of very deep water, but also had to cope with high temperatures and exposure to »

DURABLE GOODS: Materia says its Proxima resin technology may be used in a range of high pressure, high temperature applications.

Photo: Materia

Photo: Nylacast

POLYMER PREFERRED: Nylacast centralisers and spacers are made from CF110, an oil-filled cast polyamide 6.

Photo: Covestro

LAB WORK: A scientist with Covestro, the material science division of chemical company Bayer.

» drilling fluids. Additionally, it had to contain no metallic elements to protect the wellhead from any accidental damage.

Trelleborg, which 10 years ago acquired CRP Group, one of the competitors in the Girassol supply competition, developed the chemical formulation for the syntactic foam with a composite spheres buoyancy package (like most of such products, the exact chemical make-up is not made public) as well as a polymer-based clamp and fastener system.

This system had its initial use for Anadarko installing what is said to be the heaviest landing string ever, at just over 1 million tonnes, off Diamond Offshore's sixth-generation drillship *Ocean BlackHawk* in 5900 feet (1800 metres) of water in the Gulf of Mexico.

There are actually so many companies supplying thermal and pipeline insulation — quite often, the same firms that provide buoyancy also do insulation — that it would be difficult to catalogue them all. One that has done well in the component marketplace is UK-based Advanced Insulation, which supplied spray-applied insulation and encapsulations to a number of major operators, such as BP, Total, Eni and Chevron, for a range of equipment, including subsea trees and valves.

Another is US-based Materia, which recently picked up the pipeline insulation contract for Shell's Appomattox project in the Gulf of Mexico. It uses a thermosetting cross-linked polymer, marketed under the name Proxima, which is said to be incompressible at waters beyond 3000 metres (10,000 feet), thus maintaining its structural integrity. Materia will execute this job with pipe coating specialist Bayou.

There are few companies in this field with the pedigree of Covestro, the material science division of chemical giant Bayer that was spun off in 2015. Materials for the offshore sector fall into the company's Coating, Adhesives & Specialties business unit.

Covestro/Bayer had been involved in elastomers, or more specifically polyurethane polymers, for more than two decades, and the evolution of its involvement in the offshore sector was based on the material properties — corrosion resistance and a measure of flexibility. Products include both pipeline and cable protection as well as pipeline insulation, plus bend stiffeners and restrictors.

The challenges that these materials need to deal with are at the opposite end of the spectrum — low temperatures encountered on the sea bottom and the high temperature of produced fluids.

New players

There are some less familiar names trying to raise their profiles in the offshore sector. Nylacast, which dubs itself as a provider of "engineering plastic solutions", is looking for applications to replace metallic components with non-metallics. These include pipeline centralisers, bundle spacers, J-tube seals and protection for flexibles.

Nylacast also aims to enhance the performance of components through custom formulated materials. For example, its centralisers and spacers are made from CF110, an oil-filled cast polyamide 6. This standard polymer has been adapted to meet the specific application, which requires a ferrous coating on the underside and is "creep" resistant.

Also on the lookout for new opportunities is Rochling, a 190-year old privately held German company that only entered the plastics sector in 2000. Half of its €1.5 billion ($1.7 billion) turnover comes from the automotive industry. The company is looking to diversify into other markets, with oil and gas a key target, again to try to take advantage of the lightweight and corrosion resistant properties of plastics as well as the ability to reformulate existing materials.

Rochling is also producing pipeline centralisers, but as well it makes PTFE back-up rings for sealing solutions, valve seats, sheave segments for pipelay spreads, and subsea end-caps. In all of its products, it is trying to take advantage of a good coefficient of friction, thermal stability and mechanical properties of plastic formulations. U

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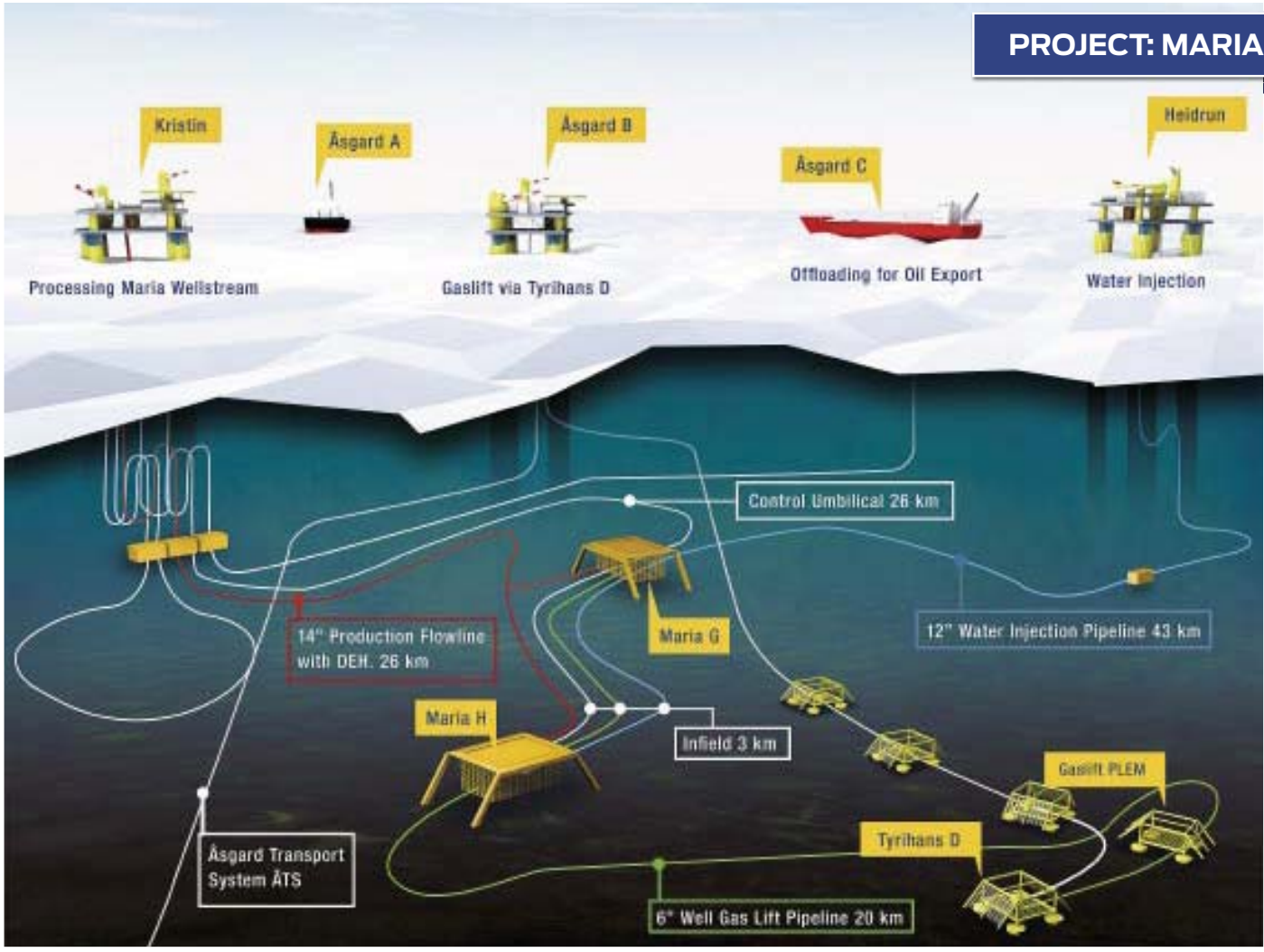

MODEL PROJECT: Wintershall's Maria project takes advantage of existing infrastructure to make the subsea development economically feasible. The field ties back to three nearby platforms in the mature Halten Terrace area of the Norwegian Sea.

Maria on the march

How does Wintershall solve a problem like Maria? By making good use of existing installations on the Halten Terrace, writes **Beate Schjolberg**.

By using existing infrastructure to the maximum through a complicated tie-back setup, German operator Wintershall is seeking to minimise investment and maximise profit at a time when low oil prices and high industry costs have forced companies and suppliers to find innovative solutions to make projects viable.

"The Maria project is quite unique on the Norwegian continental shelf, with an unprecedented set-up in terms of complexity," says Wintershall's Maria project director Hugo Dijkgraaf. "We are tying into three different hosts providing different services. This has some challenges, but the benefits outweigh the complexity for Wintershall and our partners, and also for Norwegian society, because it is a very cost-efficient solution."

Starting out with an estimated price tag of Nkr17.5 billion ($2.1 billion) in late 2014, the company had pushed the budget for its first operated development down to Nkr15.3 billion by the time the project plan was submitted just over a year ago.

Since then, Wintershall and its suppliers have kept searching for additional cost savings, aiming to make Maria even more lucrative. Norwegian analyst company Rystad Energy estimates the field has a break-even price of about $33 per barrel, making it one of the most profitable of the ongoing or planned developments offshore Norway today.

Maria is on time for its scheduled start-up in 2018, and is "very well inside" the budget, says Dijkgraaf.

"So far we have seen that we are exactly according to plan on costs, but we are working hard trying to optimise the »

SAIL AWAY: A subsea template is loaded onto the Subsea 7 vessel *Normand Oceanic* for the 210-kilometre journey to the Maria field in the Halten Terrace area.

Photo: Subsea 7

» project further and use the market conditions to improve profitability."

Operator Wintershall holds a 50% interest in the Maria licence. Its partners are Norway's state-owned Petoro with 30% and UK player Centrica with 20%. Three smaller companies — Faroe Petroleum, Spring Energy and Concedo — left the licence before the investment decision was made.

Creating value

Maria, discovered in 2010, is estimated to hold about 180 million barrels of oil equivalent, mainly oil. The field lies at a water depth of 300 metres in the developed Halten Terrace part of the Norwegian Sea, close to satellite fields producing to the Kristin and Aasgard installations.

The field's central location made it an ideal candidate for a subsea tie-back solution. Maria lies only 20 kilometres east of the Statoil-operated Aasgard and Kristin fields, which are both produced via surface installations with export systems for oil and gas in place. The oilfield Heidrun, also operated by Statoil, lies about 45 kilometres north of Kristin.

When Maria was discovered, there were already seven surface installations, several export pipelines, about 50 subsea templates and 240 production wells within a 50-kilometre radius of the field, boding well for a solution tied to existing infrastructure. There were also several undeveloped discoveries in the vicinity.

Wintershall and its partners considered five development options — tie-backs to Kristin, Aasgard and Heidrun, respectively, a stand-alone project with a floating production, storage and offloading (FPSO) platform for Maria alone, and a combined FPSO for Maria and Statoil's nearby Trestakk discovery.

In the end, the partners discarded the FPSO options as too expensive, and went for a subsea solution involving all the potential hosts. Neither facility could provide all the services Maria needed, so the operator started work on a complicated three-way set-up consisting of subsea facilities, pipelines and topsides modifications to the three host platforms.

"We see future potential for more developments of this kind."
Hugo Dijkgraaf, Wintershall

"Together with our partners, we decided on this multi-host tie-back as the development solution because we will be able to best ensure operating efficiency, utilisation of resources as well as optimising economic value creation," says Dijkgraaf. "At the same time, we are able to fulfil all requirements with regard to safety and the environment."

Talks with the three host licencees over the commercial terms for third-party hook-up were not easy. While Norwegian law states that third-party use must be allowed if there is available capacity, the companies themselves have to reach agreement on the tariffs.

Negotiations with the Heidrun licence proved particularly difficult, and Wintershall at one point appealed to the Norwegian Energy Ministry to step in and make a ruling when discussions stalled. The talks resumed, however, and an agreement was finally forged.

Photo: Subsea 7

JOINT ACTIVITY: In addition to installation services, Subsea 7 is providing three major pipeline systems, including a 26-kilometre production pipeline equipped with direct electrical heating.

Field design

The major subsea contracts went to FMC Technologies (FMCTI), for the production system and control umbilicals, and to Subsea 7 for the pipelines and for subsea installation of the pipelines, production templates and the riser base at Kristin.

The subsea system from FMCTI consists of two subsea templates, each weighing about 285 tonnes and placed about 3 kilometres apart. Each template contains a 150-tonne manifold with four well slots — two for production, one for water injection and one that can be completed either for production or for water injection.

Wintershall plans to drill two production wells and one water injector from each template, leaving the fourth slot on each available for future use. Any possible hook-up of additional volumes from new discoveries would depend on a number of factors, including oil and gas types and agreements with host installations.

The subsea production system from FMCTI "is to a large degree as possible based on field-proven technology used on previous

upstream technology

THE MARIA DEVELOPMENT

- **Production licence:** 475 BS, 475 CS
- **Licencees:** Wintershall (operator) 50%, Petoro 30%, Centrica 20%
- **Location:** Block 6406/3, Halten Terrace, Norwegian Sea
- **Discovery year:** 2010 (appraisal 2012)
- **Reserves:** 157 million barrels of oil, 2.5 billion cubic metres of gas, 2 million tonnes natural gas liquids
- **Reservoir:** Middle Jurassic, Garn formation
- **Production start:** Late 2018
- **Development budget:** Nkr15.3 billion ($1.8 billion)
- **Major contracts:** FMC Technologies (subsea system, umbilicals), Subsea 7 (pipelines, subsea installation), Odfjell Drilling (production drilling), Halliburton (drilling services), Reinertsen (Kristin topsides modifications, awarded by Statoil), Aibel (Heidrun topsides modifications, awarded by Statoil)

Sources: Norwegian Petroleum Directorate, companies

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SPECIAL DELIVERY: FMC Technologies supplied Maria's two subsea templates, each containing a 150-tonne manifold with four well slots.

Photo: Wintershall

» projects" on the Norwegian continental shelf, though "some development has been necessary to accommodate Maria specific design basis requirements," says Dijkgraaf.

The operator has also handed a technical service agreement to FMCTI for services during the development and installation phase and for life-of-field support.

The well stream from Maria's four production wells will be sent via a new 26-kilometre, 14-inch multi-phase pipeline to the Kristin platform, where it will be mixed with production from the Haltenbanken West Unit and the Tyrihans satellite field before processing at Kristin.

The production pipeline is isolated and equipped with direct electrical heating (DEH) to avoid formation of hydrates, with power provided from the Kristin platform.

"DEH was chosen to mitigate potential hydrate issues during shut downs. DEH is already in use on the Kristin host for other pipeline systems and is a field proven solution for long distance tie-backs," says Dijkgraaf.

From Kristin, stabilised oil is sent on to the storage vessel Aasgard C, while gas goes via the Aasgard Transport pipeline to the onshore terminal at Kaarsto in south-west Norway.

Meanwhile, the Aasgard B platform will provide up to 700,000 cubic metres of gas per day to Maria for use as gas lift for the production wells and for the Maria riser at Kristin. The gas will be sent via an existing pipeline to the subsea Tyrihans field, and from there through a new six-inch, 22-kilometre pipeline to Maria.

Water for Maria's two water injection wells will come from Heidrun. The platform already has facilities for treating seawater for its own wells, but will need increased capacity to serve Maria.

Heidrun will send about 8000 cubic metres per day of injection water to Maria through a new, 12-inch carbon steel pipeline covering the 46 kilometres between the fields. The injection pipeline will have an inner lining of polyethylene to provide additional corrosion protection, Dijkgraaf says.

The well stream and injection rates at the subsea facility will be controlled from the Kristin platform. Data to and from Maria will run through a 26-kilometre umbilical with electrical and fibre optic cables, which also holds lines for hydraulics and chemicals injection.

Future potential

The Maria project was approved in September last year, and the execution phase is now in full swing. The two subsea templates were built in Tonsberg by FMCTI's subcontractor Agility Group and were put in place at the field in May by contractor Subsea 7, using the installation vessel *Normand Oceanic*.

Installation of the gas lift and water injection pipelines with the pipelay vessel *Seven Oceans* are ongoing, and modifications on Heidrun and the other host platforms are under way. Drilling is set to start early next year with Odfjell Drilling's semi-submersible rig *Deepsea Stavanger*, which will stay on the field through most of 2018.

The production pipe and the water injection pipeline are both designed to allow fishing nets above, reducing the need for rock dumping. Subsea 7 expects to dump 60% less rock on top of these two pipelines once they are placed on the seabed, corresponding to a reduction of between 300,000 and 400,000 tonnes of rock.

Modifications at the host platforms are being handled mostly by Norwegian contractors. Statoil has tasked Trondheim-based Reinertsen with preparing the Kristin platform to receive the well stream from Maria, while Aibel won the job of installing a riser and expanding the water injection facilities at Heidrun.

Modifications at Kristin include a new production allocation metering system, various Maria subsea utilities equipment and three risers.

Dijkgraaf is convinced there will be more projects like Maria in the years ahead, as Norwegian operators seek to boost profits

from mature areas. By using available capacity, tie-back solutions extend the lifetime of older platforms to the benefit of both the new field and the host installations.

"Maria is one of the smartest subsea solutions on the Norwegian continental shelf in using existing infrastructure. The project requires only minor modifications of existing platforms compared to a stand-alone concept, and is a win-win approach for the Maria licence, several host licences and the Norwegian society," he says. "We see future potential for more developments of this kind, and Norway is becoming a centre of excellence for this kind of work."

Norway's Minister of Petroleum & Energy Tord Lien was also pleased when he received the development plan in the middle of the oil-price slump last year.

"The Maria field is a good example of how important it is to explore near existing infrastructure, and of how we can achieve cost-efficient developments by using available capacity in existing infrastructure," Lien said when Wintershall submitted the development plan.

More than half of Wintershall's global exploration and production budget for the next couple of years is being spent on Maria and two Norwegian Sea projects under development, the Statoil-operated Aasta Hansteen gas field and the related Polarled pipeline, in which the German player is a partner.

Elsewhere off Norway, the company operates two producing fields, having taken over operatorship of the Brage platform in 2013 and of the subsea Vega field in 2015, both from Statoil. Wintershall is also a partner in the Gjoa, Veslefrikk, Knarr and Edvard Grieg fields, providing the company with combined daily production of about 80,000 barrels of oil equivalent.

In addition, Wintershall has an extensive exploration portfolio that includes a number or promising operated discoveries, such as the North Sea Skarfjell find and the Solberg and Rodrigues deposits not far from Maria. The company plans to keep looking for innovative ways of bringing new resources on stream, says Dijkgraaf. "In Norway, Wintershall is here to stay," Dijkgraaf says. "We are continuously rethinking our working methods. The 'keep doing what you're doing' method does not apply to us."

Photo: Subsea 7

PERSPECTIVE: Pipe bound for the Maria development awaits shipment from Subsea 7's spoolbase in Vigra, Norway.

Magma goes for the full package

A whole variety of relatively small vessels should be able to use a compact deployment package now in the late stages of commissioning by Magma Global. The leading-edge pipe developer sees light well intervention as a way to ease its unique product onto the commercial stage. **Adrian Cottrill** reports.

In a significant step on the path to commercial breakthrough for its uniquely strong and lightweight composite pipe, UK company Magma Global has now developed and built a deployment system that could see that pipe at work on a light well intervention project by the end of this year.

Magma has teamed up with Scotland's Maritime Developments (MDL) — a specialist in designing and building back-deck equipment — to produce a pipe deployment package that any contractor in the light well intervention and stimulation business can rent out and mount on whatever suitable vessel it chooses.

Dubbed IDP (integrated deployment package) by Magma, the system is designed to reel out up to 3000 metres of three inch internal diameter Magma pipe rated for pressures up to 15,000 pounds per square inch. This is at the leading edge of light well intervention (LWI) requirements. The first IDP is even now being assembled, tested and made ready for shipment from Magma's Portsmouth facility on England's south coast, with a departure to the Gulf of Mexico scheduled for September. It is provisionally destined for either Galveston or Louisiana's Port Fourchon, where it will be available to the first customer to sign a deal, unless snapped up before that.

The compact package can be placed onto a vessel, complete with its 30 tonne complement of pipe, in a single 180-tonne lift. Or it can be split into two parts if lifts have to be smaller — base frame plus reel, and strongback with main equipment. The system stands 17 metres tall and has a footprint of 15 metres by 8.5 metres.

Magma is hoping the LWI industry will soon begin to appreciate the qualities of its bonded thermoplastic composite carbon fibre 'm-pipe' for such work. Not only can it handle very high pressures, but its unusually smooth bore makes for low pressure drop and hence high flowrate. It is also impressively resistant to attack by the highly corrosive fluids regularly pumped in this sector.

Photo: Magma

"The IDP system will deliver better flow rates, wider operational windows... and lower overall cost."

Martin Jones, Magma

As ever, Magma's ultimate goal is still to effect a game-change on the main deepwater floating production stage by introducing its bonded composite pipe for full-blown large-diameter riser applications (Upstream Technology, 3/2015). Its product is only a tenth the weight of equivalent steel pipe and the company wants to see it replace today's heavy thick-wall steel risers, or equally heavy expensive multi-layer unbonded flexible pipe.

However, it knows that such a breakthrough is not going to come overnight and that it must first allow the offshore industry to gain familiarity with its product by applying it in less dramatic settings. Hence its current push to break onto the commercial scene with relatively small diameter pipe in a downline role for LWI.

At the smaller end of the diameter range, from two inch to

READY TO INTERVENE: Everything needed to deploy 3000 metres of m-pipe for light well intervention — reel, chute, tensioner, winches and work platforms — is packed into this single 17-metre high self-contained package.

Photo: Magma/MDL

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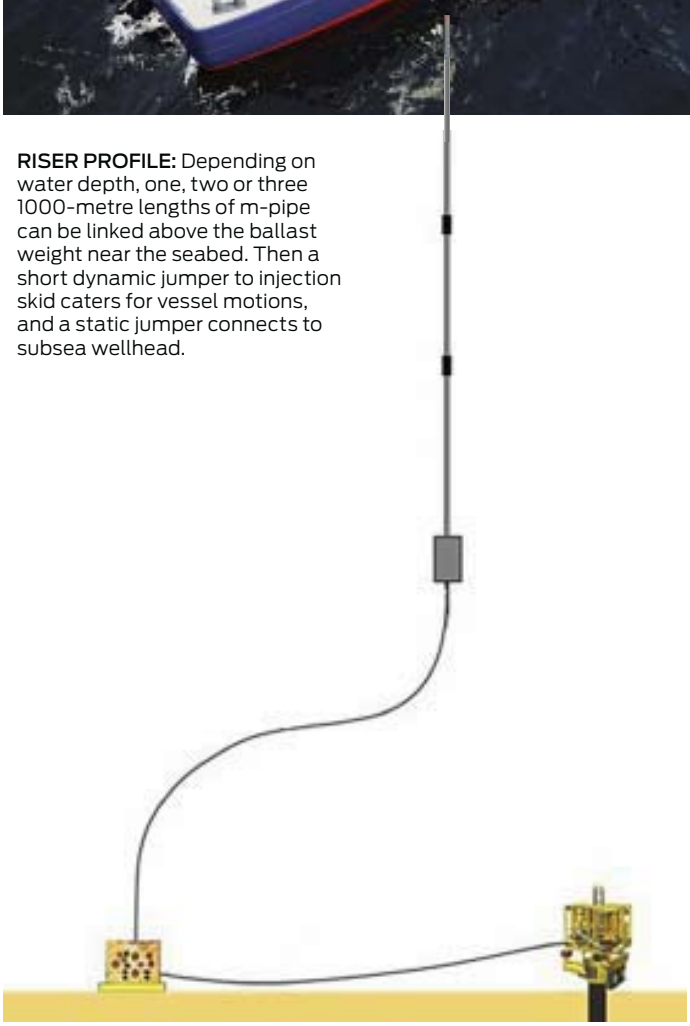
Image: Magma

COMPACT: The 180-TONNE IDP is designed for placing on most multi-purpose support vessels, with its lightweight composite m-pipe reeled out either through a moonpool or over the side or stern.



RISER PROFILE: Depending on water depth, one, two or three 1000-metre lengths of m-pipe can be linked above the ballast weight near the seabed. Then a short dynamic jumper to injection skid caters for vessel motions, and a static jumper connects to subsea wellhead.

Image: Magma

» four inch, "there is a real demand in the market for high-spec pipe — from 10kpsi, even up to 20 kpsi — for applications like chemical stimulation and scale squeeze", says Magma technical director Steve Hatton.

The company sees this role as its optimum point of entry to demonstrate a track record before building up to larger pipe sizes. It also sees renting as a good commercial model. "The dayrate rental approach allows us to take advantage of the longevity of the pipe ourselves, rather than sell it on to others," notes Hatton.

"No customer wants to take responsibility for designing the installation equipment for our pipe themselves," he says. "They want a package, they want a system, they want it all engineered." Which is what Magma and MDL have done.

In fact, "we will go on to build a number of kits with a spread of pipe specification and reeler size", Hatton continues.

This first example is Magma's likely top specification. "I don't think we'll do anything bigger than this. It will do everything and most of our customers want the high flow rate you get from three-inch pipe".

So Magma has gone from making a pipe to now offering a complete intervention system. "Both commercially and technically this is a significant step," says Hatton, "so as you can imagine, it all took quite a lot of bouncing around."

Ringing the changes

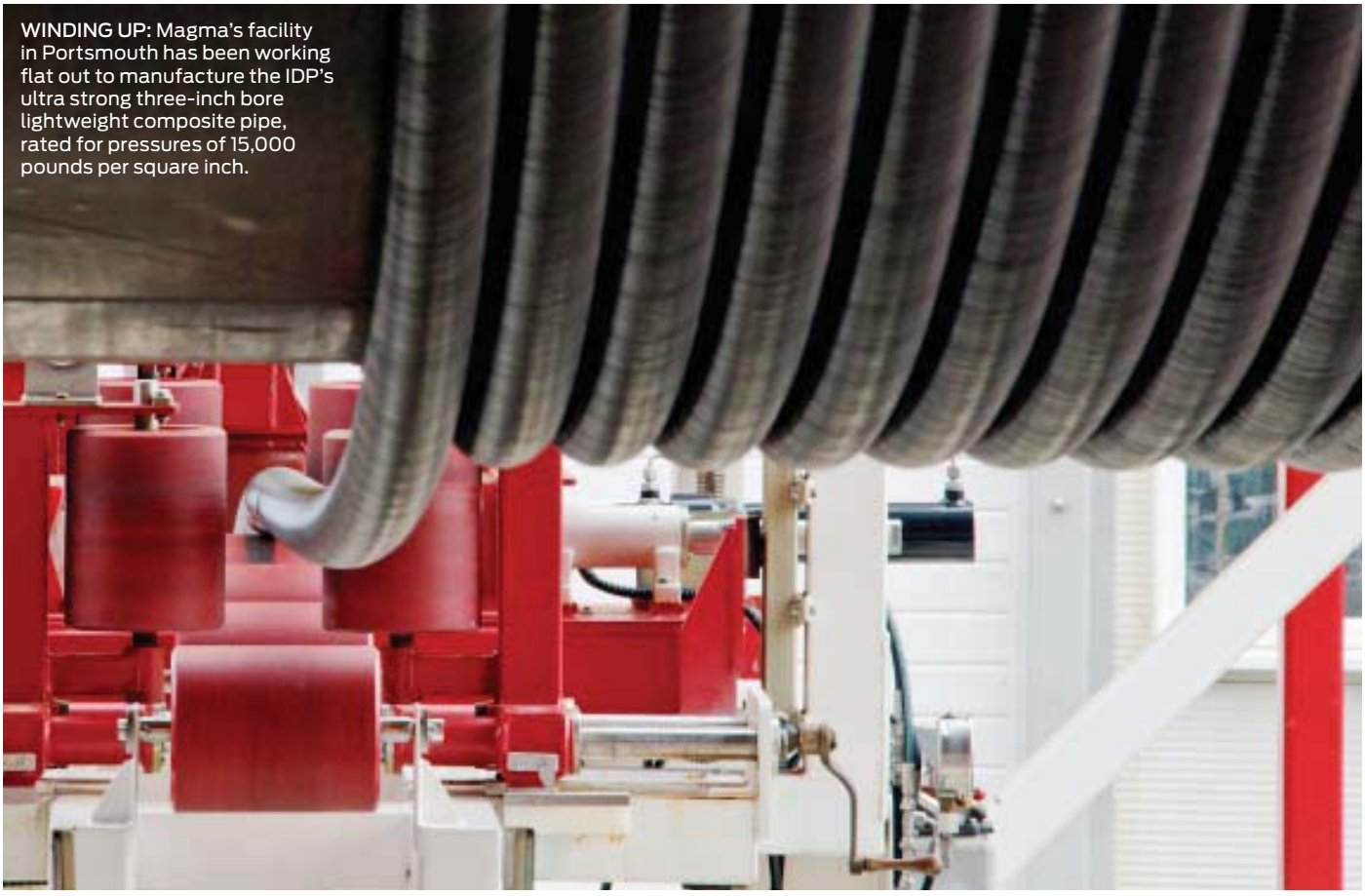
Use of a long-life and expensive product like m-pipe in the LWI business is a definite change from the traditional approach for such work. Over the last 20 years or so, contractors in this field have chiefly used relatively simple, relatively low cost, thick wall steel pipe, often thrown away after just a few campaigns.

But although the pipe used in coiled tubing (CT) operations can be wound tighter than m-pipe through plastic deformation, it is heavy, prone to damage by handling, fatigue and chemical »

surgical precision

Allseas

Photo: Magma



WINDING UP: Magma's facility in Portsmouth has been working flat out to manufacture the IDP's ultra strong three-inch bore lightweight composite pipe, rated for pressures of 15,000 pounds per square inch.

» attack. Also the upward trends in water depth, pressure and corrosive fluid demands are moving traditional coiled tubing towards the limits of its capability.

Compared with that, the Magma approach is definitely more sophisticated. And the equipment it has developed for such work is definitely expensive, costing much the same as the several million pound's worth of pipe it carries.

"But we are able to build a business case around that because we have confidence that the pipe will last a long time and we'll get a number of years of use as a rental system," says Hatton. "As always, the problem will be 'uncontrolled damage' and we've tried to protect it by having it in its own box."

Magma's philosophy is that the IDP's robustness and the pipe's longevity will enable it to match the day-rates of CT systems while also outperforming them. It points to significantly faster pumping times because of the lower pressure drop in its pipe's smooth bore. As an example of maximum flow rate, it quotes 45 barrels per minute of brine at 1500 metres. Pipe deployment speed is billed as 1200 metres per hour.

"Normally to do the job that our kit will do, you would need to use two standard CT spreads run simultaneously. Instead of taking 10 days to pump, we can do it in five days, and we can get in and out quickly," says Hatton. "Also we have lower downtime for weather."

All in all, Magma says its research indicates that time saved through using its system should offer cost savings of about 30% for LWI operations compared with the traditional CT approach.

Magma's chief executive Martin Jones summarises: "The IDP system will deliver significantly better flow rates, wider operational windows, reduced operational risk and lower overall cost. As such, we believe it is a game changer."

Photo: Magma

"The dayrate rental approach allows us to take advantage of the longevity of the pipe ourselves."

Steve Hatton, Magma

Evolution

In developing its deployment system, initially the company looked at variations on the traditional way of combining the various necessary elements — powered reel, tensioner and overboarding chute — but concluded this would take up too much deck space.

It then started talking in more detail with back-deck equipment specialist MDL in its quest to enable use of smaller intervention vessels with a light and compact system. The IDP evolved steadily over the course of 18 months or so.

Not least of the challenges is the relatively stiff nature of the pipe being handled. It is wound onto a reel with a hub diameter of 8.2 metres, corresponding to the tightest bending it will accept. And for flexibility in operation, the pipe is divided into three separate 1000-metre lengths, each in its own compartment on the reel.

When wound like this the m-pipe is coiled like a clock-spring. "So some quite clever control and safety features are needed to ensure you don't lose

FIRST SIGHT: The full IDP was built and demonstrated here at MDL's facility in Peterhead before being broken down and trucked to Magma's Portsmouth base for re-assembly, further tests and loading of pipe.

Photo: Magma/MDL

»

KEEPING IT TIGHT: Pipe deployment and recovery is driven by a 25-tonne two-track tensioner that keeps the "clockspring" of pipe on the reel properly wound up at all times.

Photo: Magma/MDL

» the pipe end and end up with a bird's nest," says Hatton. The driver and master control is a 25 tonne two-track tensioner that either pulls the product off the reel or puts it back on. In turn, the reel's drive mechanism resists with a precise back-tension.

In a typical LWI riser configuration the main downline extends from the vessel to near seabed, where a ballast weight is attached at its lower end to maintain correct tension. Vessel motions are accommodated by a flexible jumper that bridges the last 100 metres or so to the subsea well.

So the Magma system has to provide for aspects such as connection of a ballast weight in the two to five-tonne range, as well as for passage of end fittings and the intermediate connection of 1000-metre pipe lengths. In Magma's case, both the main line and the dynamic jumper near the seabed are formed by identical pipe, bringing the advantage of consistent structural properties either side of the connection at the ballast weight.

RiserTec report

A further element in Magma's strategy has been to commission an independent third-party validation of the system, also examining optimum configurations, operational envelopes and procedures.

Boutique riser engineering consultancy RiserTec, headed by John Shanks, has just completed a four-month study and its details are due to be provided at an event organised by Magma in Houston on 29 June.

"We wanted to analyse a broad spectrum of riser configurations and be able to say 'yes, we can do that'," says Hatton. "The issue comes down to waves and currents — how big a wave can we accommodate, and what is the worst current profile we can take, with its drag on the pipe."

The aim was to be able to work reliably for 95% of the time, which in the Gulf of Mexico equates to a 2.5-metre significant wave height and a current of about 1.2 knots.

"RiserTec has a way of running a lot of analyses very quickly — lots of ballast weights, jumper lengths, buoyancy distributions," says Hatton. "It ran its analyses for five different vessels, ranging from a small one that moves around a lot under what is quite a large payload for it, right up to very stable large construction vessels.

"All the indications are that everything looks good and that we have a very broad capability to accept a wide range of vessels, a wide range of contents densities, and to keep working through bigger waves and bigger current profiles without worrying about fatigue."

In recent months, Magma's production line in Portsmouth has been working flat out to manufacture the three kilometres of m-pipe that the IDP will carry. The pipe's 20-millimetre thick wall is built up layer by layer by winding on a tape of polymer and embedded carbon fibre in a process likened to 3D printing. During this process, the pipe length is shuttled back and forth between two large spools either side of the central "black box" station where high-power lasers fuse on the tape.

At the same time, the elements of the IDP have been trucked from Peterhead to Portsmouth and are being re-assembled there for testing and loading with this newly-made supply of pipe. Early in September, the package should be ready to ship out for its first job.

The destination is not yet set in stone, but "our base case at present is to send it over to the Gulf of Mexico where it will be kept, ready to go offshore", says Hatton. "But this is a short lead-time area of business, and we've been chasing opportunities in the Mediterranean and West Africa as well, so if something comes up there before September the package might just go to one of those places instead."

Back-deck specialist majors on portability

During its 16-year life, Scottish company Maritime Developments (MDL) — the specialist outfit chosen by Magma Global as it partner to develop the m-pipe deployment system — has established a growing presence in the design, manufacture and delivery of back-deck equipment for the oil business, *writes Adrian Cottrill*.

Founder and chief executive Derek Smith comes from the fishing industry and that was where the company cut its teeth, building winches and net drums and the like. In more recent years, MDL has steadily built up experience in systems for handling flexible risers, flowlines and umbilicals.

"I guess we've always been portable, that's what sums us up," says Smith. "We focus on the cheap and cheerful end of the spectrum, where water depths are relatively shallow, top-tension does not exceed 150 tonnes, and vessels of opportunity can be used."

The company also puts a high priority on the need to keep vessel days to a minimum, whether that be on the critical path during mobilisation and demob of its systems, or in activities such as reel changeover at location.

In this way, MDL has found a fruitful niche in providing portable systems that large Surf contractors such as Subsea 7 and Technip can mobilise rapidly for smaller jobs instead of using their top-of-the-range lay-vessels. "Why use a sledge hammer to crack a peanut," quips Smith, "mini systems can probably do about 80% of market."

He notes that "one of our biggest clients to date has been Subsea 7, with well over £20 million of kit supplied to them in the last few years".

The height of MDL's art for standard flexpipe laying is its largest piece of kit to date, delivered to customer Technip last summer. This is a complete portable system for vertical laying of flexible pipe — dubbed PVLS — now in its second season of work at the Kraken oilfield in the UK North Sea.

Photo: MDL

PORTABILITY: Scottish specialist MDL's most prominent output of late has been its third generation reel drive system (in foreground here at its Peterhead yard), and the large portable vertical lay system for flexpipe it has provided for Technip (dominating the background).

With a four-track tensioner of 50-tonne capacity, this has handled flexpipe risers approaching 18 inches outside diameter in the fairly shallow 120-metre water depth at the field. The tower can take an 85-tonne tensioner if desired.

Rather than calling for a work vessel to go to a particular port to collect it, the PVLS can be broken down and transported by road for assembly off the critical path at the same quayside as the waiting pipe reels. Then, when the vessel arrives, everything can be lifted aboard and sea-fastened at the same time.

Another equipment line that figures large in MDL's spectrum is its reel drive system, designed for loaded reel weights up to 500 tonnes. This has now evolved to reach its third generation.

This latest variation of drive joined the company's rental range in July last year and has now been used on two campaigns — on the Kraken field along with Technip's PVLS last year, and this year at Nigeria's Agbami location.

It is more compact than earlier versions, says Smith, and "the reel cradles and rail system are built in one, so you simply sea-fasten this to the vessel and then lift the reels onto the cradles, which have special clamps that hold onto the rim".

In the context of MDL's normal work, the Magma IDP system is a definite one-off, although, as ever, a major priority has been to keep it compact. "During the tour we did with Magma in the early days, showing concepts to potential users, the regular feedback we got was 'far too much real estate'," says Smith.

Now, he is "particularly proud of how we've managed to put something that requires a 10-metre reel into not much more space than that reel itself. We went through maybe eight design iterations before we started cutting steel."

As to the particular challenges of the Magma task, "one of the key differentiating things was that they wanted to deploy individual one kilometre lengths of pipe and join them together as water depth demanded", he notes. "Handling of the mid-water connection introduced considerable complexity and we had to combine a number of products to make sure this is a slick operation."

Photo: MDL

"We've always been portable, that's what sums us up."

Derek Smith, MDL

The stiff nature of Magma's product — "this pipe wants to be a straight line" — was also an unusual aspect for MDL, with the pipe wrapped in separate compartments on quite a large drum and calling for back-tension at all times to prevent uncontrolled unwinding of this "clockspring".

Photos: McDermott

FLAGSHIP ASSET: McDermott's *DLV 2000* underwent sea trials in the Malacca Strait before sailing to its first assignment off Western Australia.

Versatility first

McDermott's *DLV 2000* makes its debut off Western Australia, joining the subsea installation phase of the massive Ichthys LNG project. **Jennifer Pallanich** gets the details on the company's new flagship.

Some years back, McDermott set its sights on joining the top ranks of subsea players. Central in its playbook was a versatile installation, heavy-lift and pipelay asset (Upstream Technology, 02/2013). The *Derrick Lay Vessel 2000* (*DLV 2000*) is now part of the fleet and has almost three years of a backlog for work off Western Australia.

McDermott believes the *DLV 2000*'s flexibility will appeal to customers by minimising the number of vessels required in a field.

John Macpherson, who served as the project manager for the vessel's construction, says the *DLV 2000* has the capacity to carry out different projects.

"If it's in the field doing pipelay, and they need a heavy lift or subsea work done, we can change modes and do that work," Macpherson says. "We won't have to bring in another vessel — or make us leave, to bring in another."

The *DLV 2000*, with its 2000-tonne crane, is capable of S-lay and heavy-lift activities in water depths to 3000 metres and has accommodations for 400 people. The company does not expect to use the full capacity of the accommodations during typical pipelay, subsea or heavy-lift operations, Macpherson says, adding that McDermott expects to make extra accommodations available to clients as needed.

"She's a pipelay vessel primarily, and we should never forget that. She can heavy lift and do subsea work because of the crane set-up," says Macpherson, who is slated to become McDermott's senior director of quality, health, safety, environment and security in July. "She's a Swiss Army knife, almost, but a real decent pipelay vessel."

The *DLV 2000* has almost an acre of clear deck space, and parts have been strengthened for additional capabilities, such as handling pipeline end terminations. The 2000-tonne NOV/AmClyde crane has three other hooks — 600 tonnes, 250 tonnes, and 80 tonnes — to offer additional flexibility.

In addition, the vessel has a 250-tonne NOV/Hydralift AHC knuckle boom crane and a 100-tonne Liebherr fixed boom crane to support operations.

Both of the *DLV 2000*'s abandon and recover (A&R) winches can work in 3000-metre water depths. One A&R spool is rated to 250 tonnes, and the other to 500 tonnes. It can S-lay coated pipe of 4.5 inches to 60 inches in deep water in either single or double joint configuration over a 100-metre fixed stinger.

Developed by Keppel's Marine Technology Development design division, the vessel is said to be capable of achieving efficient pipelay rates for long trunklines and operating in severe weather conditions. Although designed for S-lay pipelay, it can accommodate a deepwater, 500-tonne flex lay system that can be installed as needed.

McDermott worked with Keppel Singmarine, a wholly owned subsidiary of Keppel Offshore & Marine, to develop the specifications and ensure that Keppel's proprietary design would meet McDermott's needs.

"We didn't go for first-of-its-kind

ENTRY PACKAGE: The *DLV 2000*'s maiden job involves installing large subsea spools, laying infield umbilicals and lifting several subsea distribution units for the Inpex Ichthys project.

technology. We weren't trying to be clever about it. We just wanted to make sure what we did put in there was solid and reliable," Macpherson says, adding the team set out to "focus on quality. Schedule was important, but we wanted to be sure we delivered the right vessel."

McDermott used a larger project team than might normally be involved on a newbuild. The philosophy behind sending 30 to 40 crew members in as subject matter experts to work alongside the construction team helped the crew "buy in" to the vessel.

"I don't need to sell the vessel to them. They're not coming in and saying, 'I don't like this' or 'we need to change that'. The vessel's theirs already. They already own it," Macpherson says.

McDermott also had early engagement with the vendors, carried out audits and early inspections and attended factory acceptance tests in a bid to catch potential issues early on so they could be dealt with on the vendor's premises.

"We had way fewer major issues. We didn't see anything crazy there. I put that down to the programme we put into place," he recalls. "We spent money early on to avoid headaches later."

McDermott accepted delivery of the *DLV 2000* in May following sea trials in the Malacca Strait. The vessel was scheduled to arrive off Australia for its first project in June this year.

For the Inpex-operated Ichthys field, in 260-metres water depth in the Northern Browse basin off Western Australia, the *DLV 2000* will install large subsea spools, lay infield umbilicals and lift several subsea distribution units that provide hydraulic, chemical and electrical distribution from the umbilicals to the subsea drill centres. McDermott's other new subsea installation vessel, the *Construction Support Vessel 108* (*CSV 108*), is already working on the project.

"She's a Swiss Army knife, almost, but a real decent pipelay vessel."

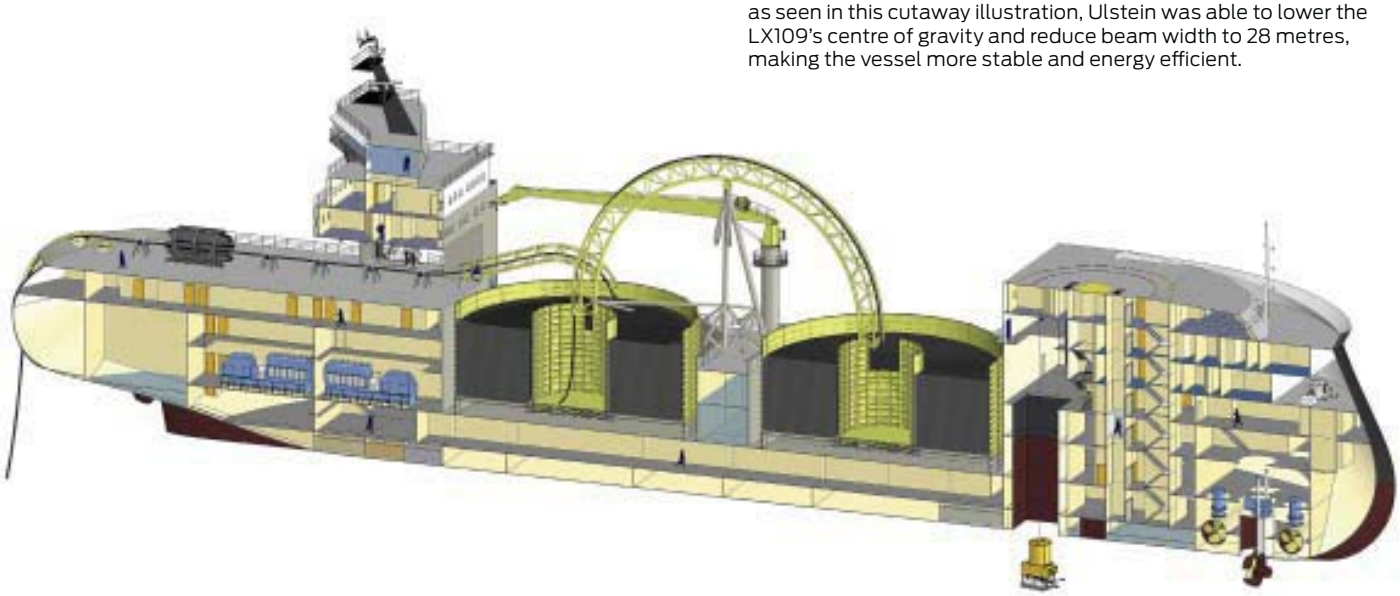
John Macpherson, McDermott

The *DLV 2000*'s Ichthys workscope is expected to run until November 2016.

After the initial installation work, the vessel is scheduled to carry out pipelay trials, followed by further work in the Ichthys field. The *DLV 2000* will then mobilise to Woodside's Greater Western Flank phase two project in the North West Shelf region off Western Australia, where it will carry out its first pipelay job installing 35 kilometres of 16-inch corrosion resistant alloy pipeline in 70 to 130 metres of water. That job is expected to take 12 to 18 months.

Macpherson is understandably proud of the newest addition to McDermott's fleet.

"We've proved that we're with the big boys, or what we used to call the big boys," he says. "We're making the right moves. We're going the right direction. I think this vessel is going to perform quite well for the company." U



SMOOTH SAILER: By lowering the cable carousels into the hull, as seen in this cutaway illustration, Ulstein was able to lower the LX109's centre of gravity and reduce beam width to 28 metres, making the vessel more stable and energy efficient.

State of the arch

By combining proven technology and smart engineering, a new cable-lay vessel design from the venerable Ulstein Group brings some fresh thinking to a niche market, writes Russell McCulley.

Cable-lay vessels tend to share some common characteristics, most notably large, flat decks and wide beams to accommodate heavy, large-diametre carousels. It is a functional layout, but one that comes with trade-offs — a high centre of gravity, for one, and less than optimal seakeeping.

Ulstein's new LX109 cable-lay vessel design aims to address those issues while significantly extending the amount of cable that can be installed in a single piece.

"We saw that there were jobs that required a long, continuous cable, but a lack of vessels in that market," says Ulstein Design & Solutions marketing and sales manager Nick Wessels.

The solution, and the LX109's most prominent feature, is the Cable Arch, designed in collaboration with sister company Ulstein Equipment, a 22-metre high arch with a span of 33 metres connecting the forward and aft cable turntables. The structure enables the load and lay of one continuous cable weighing up to 12,500 tonnes, or roughly 200 kilometres of conventional subsea power cable.

To accommodate the added tonnage, the Ulstein LX109 design positions the turntables below deck, lowering the vessel's centre of gravity when loaded. Dividing the payload over two carousels also allowed Ulstein to pare the beam width to 28 metres, considerably slimmer than that of a typical cable-lay vessel. That makes the new design more efficient to operate, Wessels says.

The design concept grew out of an earlier project, the subsea rock installation vessel *Bravenes*, scheduled for delivery to Van Oord later this year. Ulstein designed that vessel with recessed rock holds, resulting in a 14,000-tonne capacity installation vessel with a relatively narrow 28-metre beam. "We looked at what we had done and thought, 'we could do the same with a cable-lay vessel'," Wessels says.

"This is a dedicated cable lay vessel that's more efficient."

Ko Stroo, Ulstein

Long reach

The Cable Arch eliminates the need to split the cable in order to load it onto the carousels, says Ko Stroo, naval architect at Ulstein and the LX109 project manager.

"The Cable Arch, which was designed in collaboration with Ulstein Equipment, allows us to put the cable into two separate drums without cutting it. And that allows us to reduce the beam significantly and get a better vessel with good sea-keeping and higher transit speeds," he says.

During loading, cable enters the vessel at the stern and is fed from the loading arm to the Cable Arch, which guides the cable onto the forward carousel. Once the forward carousel is loaded, the cable is guided over the arch to an opening in the centre of the aft carousel. As both turntables revolve, the aft carousel is spooled up while the Cable Arch rotates on its own axis, without torsion. The

BIGGER PAYLOAD: Ulstein's new LX109 cable-lay vessel concept is capable of carrying 12,500 tonnes of continuous power cable on two carousels.

WIDE VIEW: An asymmetrical bridge, located aft, gives an unobstructed view of the work deck and cable-lay stingers aft and the turntables forward. Accommodations, a moonpool and two multipurpose hangars are located in the bow.

loading arm guides the cable as it feeds onto the aft carousel.

While some deck equipment is "off the shelf", Wessels says, a patent is pending on the Cable Arch, and the loading arm and cable lay stingers on the aft are Ulstein Equipment designs. The LX109 design allows for a small deck crane mid-ship and a knuckle boom crane on the aft.

The front of the vessel includes accommodations for up to 90 people and multipurpose hangars located port and starboard. The hangars can accommodate remotely operated vehicles (ROVs), workboats or various subsea burying tools, says Stroo. The equipment may be deployed over the side or through a centreline moonpool located between the hangars.

Another distinctive feature is the asymmetrical bridge, located aft, which provides unobstructed views of the work deck and cable stingers aft and the turntables forward.

The LX109 is built atop Ulstein's successful X-Bow hull design as well as the company's X-Stern design, which allows the vessel to operate more efficiently in stern seas.

"This is a dedicated cable lay vessel that's more efficient," says Stroo. And versatile: "Because of the Cable Arch, you can take larger loads onboard in a single continuous piece, but you can still opt, of course, for a more conventional setup with two separate cables onboard." The LX109 can achieve speeds up to 15 knots, "which is quite fast for a cable lay vessel". The speed and fuel efficiency make the ship suitable for worldwide mobilisation, he adds.

Proven technology

While Ulstein had the offshore wind market in mind when drawing up plans for the LX109, the vessel could find a good deal of work in the oil and gas sector.

"This vessel is dedicated for power cables, looking at both export cables for offshore wind — larger, longer cables — and interconnector cables for the subsea connection of grids between countries," says Wessels. "Cable-laying vessels will need to go further offshore, and in harsher environments, to lay these large interconnector cables."

Offshore oil and gas operators, pressed by regulators to cut emissions and under economic pressure to make better use of existing offshore infrastructure, are likely to choose electricity to power platforms.

"A lot of platforms can get their power from shore or from another platform instead of making their own energy or burning hydrocarbons on the platform itself. So we also see a market in the oil and gas industry for power cables being laid between platforms, and also from shore to field," Stroo adds.

Ulstein has presented the LX109 to a number of cable-lay contractors. "We have been looking at this market," Wessels says. "They more or less always use ship-shaped barges or barges with flat decks, and we want to give them an alternative."

The reaction so far has been positive from both cable manufacturers and cable lay contractors, who have also offered "some good further input" regarding the design, he says.

"It is a design that can be further customised, and that we would like to work out further with a pragmatic, open-minded and forward-looking contractor into a real vessel," Wessels continues. "This is our idea based on what we see in the market and what might fulfil the needs of the future."

"We saw that there were jobs that required a long, continuous cable, but a lack of vessels in that market."

Nick Wessels, Ulstein

Those needs could extend to extremely cold environments as the offshore industry ventures farther north. The LX109 design, he says, could be outfitted with a shelter over the carousel area to allow operations in very cold climates.

The innovative Cable Arch notwithstanding, most of the technology advances going into the LX109 design are incremental, rather than groundbreaking. "It's based on proven technology — there's no rocket science involved in this one. It's just another way of applying existing technologies," Wessels says.

"What we try to achieve is to make innovations which are feasible from the beginning and based, where possible, on proven technologies. And this was true of optimising the cable-lay vessel."

Demystified

PARKING PLAN: Using the ABS Guide for Lay-Up & Reactivation of Mobile Offshore Drilling Units, asset owners have a systematic way to deactivate complex assets, such as this drillship, and bring them back online safely.
Photo: © marchello74/Shutterstock.com

Stacked with care

In the face of ultra-low rig utilisation rates, drilling contractors are stacking more rigs than ever. Laying up a drillship incorrectly can pave the way for damage to the structure and crucial systems, costing extra time and money to reactivate the asset, writes Jennifer Pallanich.

Operators dropping or slimming drilling programmes have left drilling contractors with few options but to stack rigs at a pace reminiscent of the bust cycle of the late 1980s to early 1990s.

"But newer rig designs being stacked are much more complicated than they were 30 years ago," says Dave Forsyth, chief surveyor offshore at classification society ABS. "High-spec drillships are very complicated pieces of equipment. They're controlled by a lot of programmable logic controllers. There are a lot of computer systems on board. You can't just close the door and walk away."

During the downturn of the late 80s and early 90s, many rigs were laid up for four to five years.

"Basically, some of these rigs were just left at the dock. They locked the doors and walked away. When we tried to reactivate them, there was a lot of steel wastage that had to be renewed, and equipment had to be replaced or overhauled," Forsyth says.

It often took four to five months to return a rig to safe working condition, and more if long-lead items were involved, which might be the case if the asset had been used as a "spare parts" resource, he adds.

James Brekke, account manager ABS Global Offshore, says drilling contractors must decide whether it is more economically viable to keep the rigs available and ready to go back to work at a minute's notice or put the rigs into cold storage only to bring them back into service after the industry turns around.

In a warm stack, minimal personnel remain on board to run and maintain certain systems. Warm-stacked rigs can more quickly return to service than cold-stacked rigs.

In a cold stack, no personnel remain onboard. Preparation for cold stacking might include dehumidification and corrosion protection, care for computer equipment and monitoring.

However the drilling contractor decides to store a rig, a primary consideration is that the asset remains secure. For instance, dynamic positioning systems will no longer be used, so the floater must be moored. Such a change requires modifications such as anchors and mooring lines. The rigs also should be placed in benign waters, where they will not be affected by hurricanes or typhoons, unless people will remain available to handle or move the rig during major storms.

"It has to be secure, wherever it is," Brekke says.

Photo: ABS

IDLE IRON: Laid up rigs off Invergordon, Scotland, are indicative of the increasingly common choice among drilling contractors to stack inactive assets.

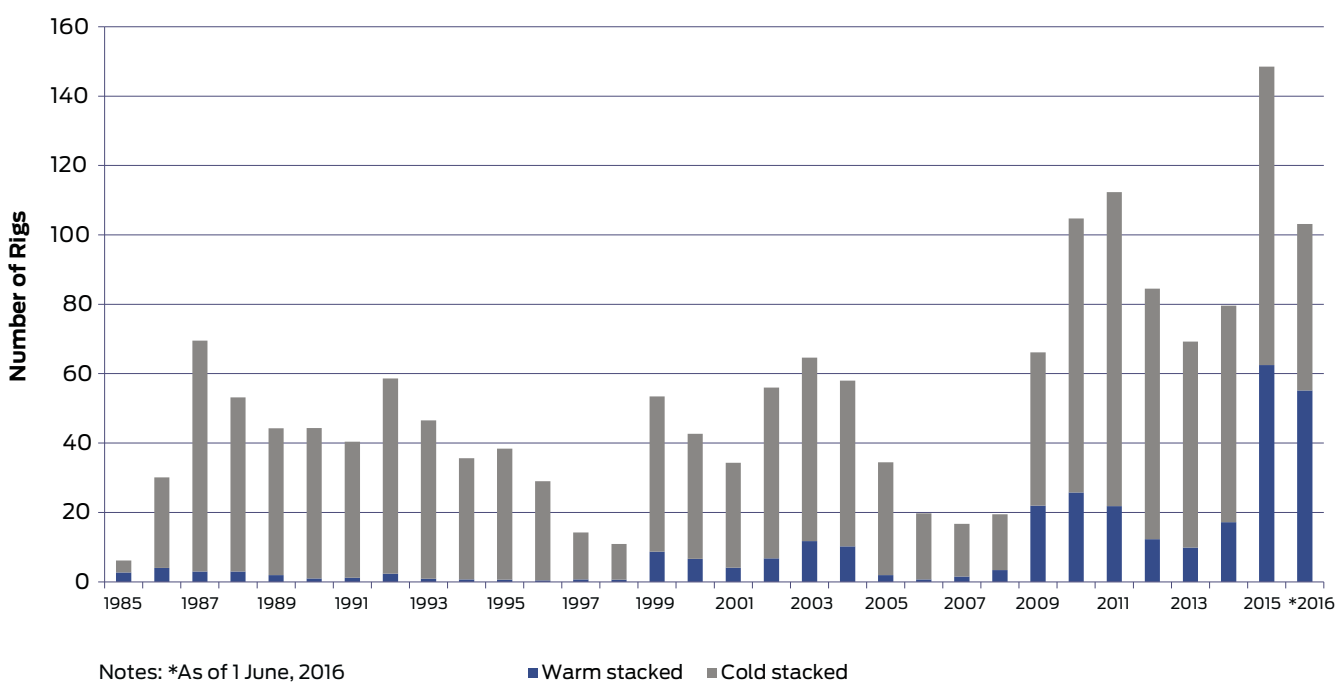
Photo: ABS

"High-spec drillships are very complicated pieces of equipment ... you can't just close the door and walk away."

Dave Forsyth, ABS

upstream technology

WORLDWIDE COUNT OF STACKED JACK-UPS, SEMISUBS AND DRILLSHIPS SINCE 1985



BY THE NUMBERS: IHS placed the average warm and cold-stacked rig count through to the end of May at 103, which is about 12% of the current supply. The total is down from last year, which averaged about 149, or 17% of the supply, stacked. IHS attributes the utilisation rate change to a reduction in the total fleet supply following a number of rig retirements and scrapping announcements. The number of warm-stacked units skyrocketed last year, as rig contractors attempted to keep their rigs available for work in the event of a market recovery. IHS notes this is a reversal of the trend from the late 1980s downturn, when rigs that were stacked were unlikely to return to active service. Following the 1986 oil crash, about 70 units, or 11% of the 1987 supply, were warm or cold stacked.

Source: IHS RigPoint

Photo: ABS

HANDS ON: Preserving equipment and machinery on board creates a safe environment and a lower risk of safety issues for warm-stacked or cold-stacked units.

Photo: ABS

"There's a standard that (drilling contractors) can do this work to that gives them that security."

Jim Brekke, ABS

Planning process

Contractors either craft their own stacking plans or work with a classification society like ABS to create a systematic programme that addresses structure and equipment preservation as well as location and reactivation of the asset.

When developing a stacking plan with a classification society, Brekke says, "there's a standard that they can do this work to that gives them that security".

Without a pre-approved cold-stack plan, Forsyth says, it can take one to three months to survey the rig and bring it back into service, as long as the rig has been well preserved during the lay-up. With a pre-approved plan, he adds, the same rig could be back on contract in under a month.

Reactivating a rig means ensuring the rig can work safely when it returns to service. Special focus is given to ensure there are no computer glitches and that all systems function properly. Such plans also cover a modified annual survey, which varies from a working rig's survey.

"It gives the owners an annual survey that's appropriate for a rig that's laid up," Brekke says. "If a rig has not been working for a few years, some equipment does not need the same type of survey that would be required if the rig were in operations. If the rig were warm stacked, the survey would need to cover all the equipment that deals with taking care of people on board — life-saving equipment and so on."

Forsyth notes that while jack-ups are "a lot less complicated" than semisubmersibles and drillships, it is crucial that the jacking gear be properly preserved. This can be as simple as filling the gear boxes with oil once the jack-up is on location and has been jacked up to the appropriate air gap. While this is not complicated to do, he says, this step was not done much in the late 1980s and early 1990s when so many jack-ups were stacked.

"Most of the jack-ups that are being laid up now are not being laid up in accordance with our plans, so we don't know how the lay-up is being done," he adds.

As of this year, ABS offers five different life-cycle notations for rigs it classifies, an expansion of the three life-cycle notations of the past. The original three included an option where a laid-up rig is out of service but without a formal plan with ABS for the lay-up. Options two and three include both warm and cold stacks, where ABS reviews the stacking procedure.

The two new notations are enhanced warm and enhanced cold lay-ups. The enhanced status denotes a plan that covers all the basics for the general warm or cold-stack status but adds such things as a risk analysis of the lay-up location and includes specific procedures for elevated site assessment for jack-ups and mooring analysis for drillships and semis.

"We built in a lot of lessons learned from the last time rigs were laid up for long periods of time," Forsyth says.

The addition of the enhanced notation stems from a request from drilling contractors that were "getting pushback from their underwriters and insurance" companies about how rigs were being laid up, he says.

"Sixth-generation drillships are worth probably $500 million, so they want to know the asset is being maintained to a standard."

What's new in ABS's latest lay-up guide is the option to provide reviews during lay-up and reactivation, along with surveys throughout, including annual lay-up surveys. Brekke says this systematic approach should mean that an owner's up-front investment could result in a faster reactivation.

For instance, if an operator asks a drilling contractor to bring a laid-up rig into service in two months, the fact that the drilling contractor had followed a systematic plan for lay-up would pave the way for a successful reactivation. Late delivery would mean loss of dayrate for the rig owner, not to mention a tarnished reputation for showing up late, Brekke notes, while the operator would suffer delayed revenue in their field.

"This lay-up guide helps bring that predictability," he says. U

Images: NeoDrill

CAN DO APPROACH: NeoDrill says the Conductor Anchor Node (CAN) provides a stable and reliable foundation that also mitigates the risk of conductor bending and fatigue.

Sharp turn for Barents exploration

The Barents Sea is filled with huge shallow structures that are difficult to drill with traditional horizontal well techniques. OMV employed an innovative well foundation technology that could make successful oil and gas extraction possible in the frontier region, writes **Ole Ketil Helgesen.**

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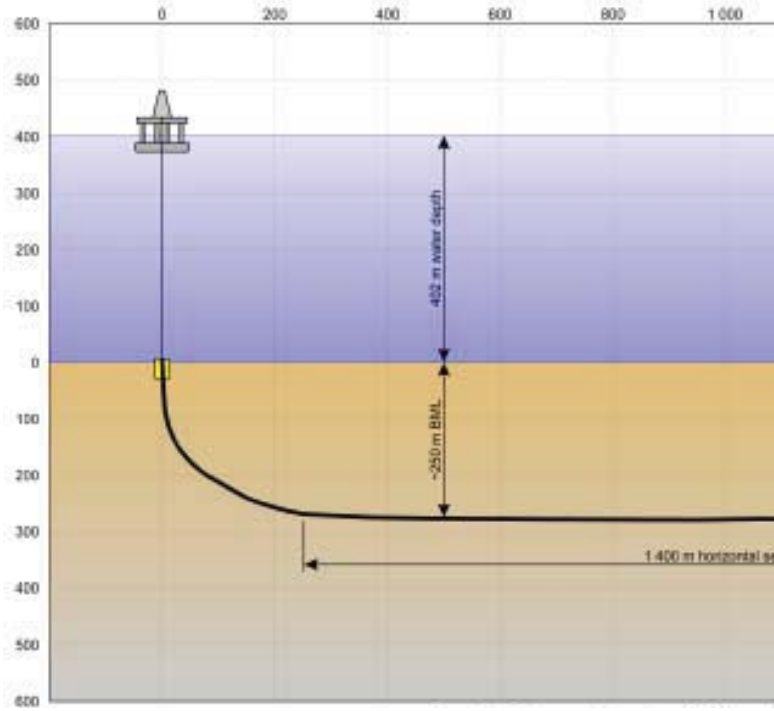
STABLE FOUNDATION: The Wisting Central-2 CAN was installed in late 2015.

Well Trajectory Wisting Central II



Source: NeoDrill (survey data courtesy of OMV Norge)

Drilling experts in Norway are working hard to solve how to produce efficiently from shallow reservoirs with low pressure and low temperatures. The giant task is to develop economical solutions to drill long, shallow horizontal wells to ensure a high recovery rate from each well.

Austrian operator OMV was the first operator to test some of the new technology being developed for the task. This winter, OMV drilled a well at the Wisting discovery in the Barents Sea off Norway that proved the feasibility of horizontal wells in an unusually shallow reservoir, only 250 metres (820 feet) below the seabed.

Bernhard Krainer, senior advisor at OMV, and until recently its managing director — his replacement, David Latin, will be responsible for OMV's North West Europe business — calls the Wisting Central 2 appraisal well "a tremendous success".

"We demonstrated that it is possible to produce Wisting with long horizontal wells, which will enable us to develop the field with fewer wells and significantly reduce costs," says Krainer.

The operation was not easy, the main challenge being the tight angle of the well trajectory over a very short interval. "We are talking about a 200-metre vertical section in which we needed to achieve a 90-degree turn from vertical to horizontal orientation," he says. "This has never been tried from a floating drilling unit before, but we wanted to confirm a development concept for such a shallow reservoir."

New technology

The operation was possible with the help of a new well foundation technology developed by NeoDrill, a small Norwegian company with five employees. Its innovative Conductor Anchor Node, or CAN, made the record-breaking shallow horizontal well at Wisting possible, proving the feasibility of developing the shallow Barents reservoirs.

The technology enables a stable and easily installed well foundation that saves cost and time and makes the top hole more secure, says NeoDrill general manager and chief shareholder Harald Strand.

The CAN eliminates the weak link in current well design by providing a stable and reliable foundation, which also mitigates the risk of conductor bending and fatigue, Strand explains.

NeoDrill's CAN technology enabled OMV to start curving the well only 10 metres below the seabed.

With a standard cemented conductor foundation a much deeper kick-off would have been necessary.

NeoDrill's technology, based on a suction anchoring system, has been applied for conventional as well as more technically challenging wells in various fields on the Norwegian and UK continental shelves, he says.

NeoDrill further developed the conventional high load-carrying capacity suction anchor into the new CAN system along with technology for top-hole well construction.

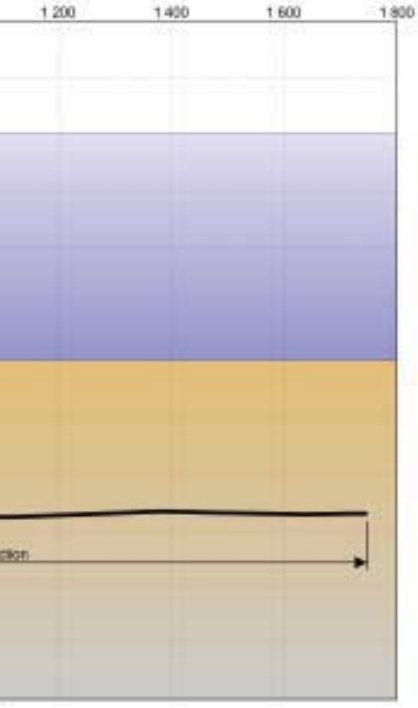
The company says the CAN technology is compatible with today's heavier blowout preventer stacks and can be installed and retrieved with smaller marine vessels, in accordance with the design objective of pre-rig conductor installation.

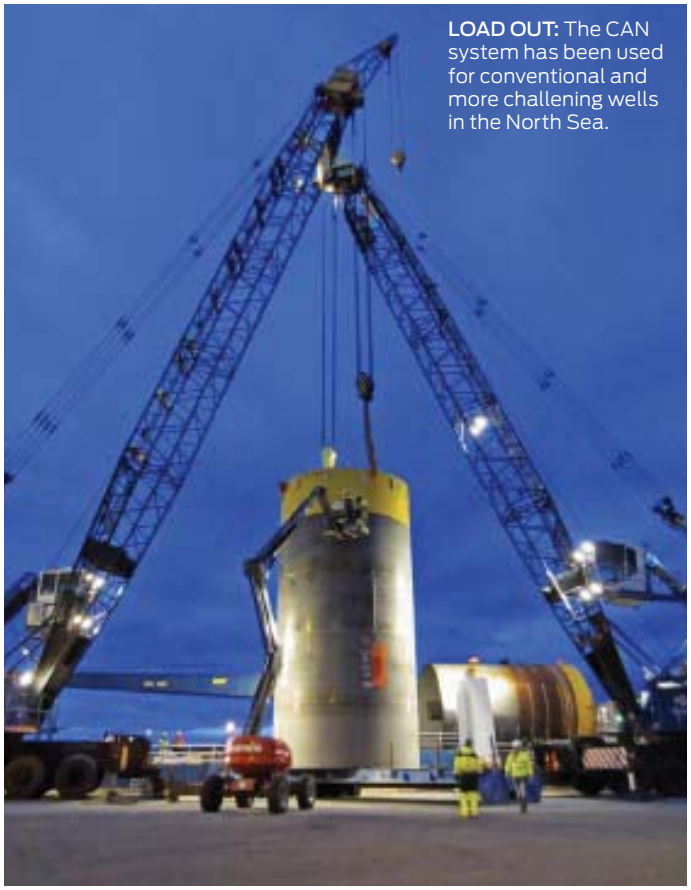
Suction anchors have been used in the offshore industry for more than a quarter of a century to provide solid and secure mooring in deeper waters. The technology is being applied more broadly — in April, Statoil launched its Cap-X subsea concept, based on a subsea well integrated in a suction anchor (see article, page 12). Statoil Technology Invest owns a 30% stake in NeoDrill.

Barents milestone

Wisting Central 2, the first horizontal appraisal well in the Barents Sea, set a new drilling record as the shallowest horizontal offshore well drilled from a floating drilling facility. Water depth at Wisting is 402 metres (1320 feet). The well started vertically and was successfully steered into a horizontal orientation within a 250-metre (820-foot) depth interval. The total well length is

TURNING POINT: Illustration showing the well's vertical depth (left) and horizontal deviation from the spud location in metres.





LOAD OUT: The CAN system has been used for conventional and more challenging wells in the North Sea.

Photo: OMV

"This has never been tried from a floating drilling unit before, but we wanted to confirm a development concept for such a shallow reservoir."

Bernhard Krainer, OMV

2354 metres (7723 feet) including the horizontal section of 1450 metres (4757 feet).

OMV expects to raise the resource estimate at Wisting, Norway's northernmost oil discovery, to the high end of its previous estimate of 200 million to 500 million barrels, following a successful drilling campaign this year. While the well "will probably not increase the high end of the current 200 million to 500 million barrel range... it will certainly move the lower end significantly upwards", Krainer says.

The drilling operation was hampered by some bad weather and mud losses in one of the fault sections, though the total cost of the well was within budget. Latin says OMV now has all the information it needs "to focus on finding a concept that enables us to develop an economically viable project".

OMV plans to reach a decision early next year on whether to continue at Wisting and potentially launch front-end engineering in 2018, with production start-up around the middle of the next decade.

Despite Wisting's significant resources, the development still faces major obstacles, with the shallow reservoir having a very low temperature at 17 degrees Celsius (62 degrees Fahrenheit) and low pressure at 70 bars (1000 psi).

"This means water will probably be injected from the first day of production to maintain reservoir pressure," says Latin.

The reservoir also has several fault zones, which has resulted in some of the resources leaking through the seabed. However, the main obstacle is its remote location.

"With uncertainty about future oil prices, we need to find solutions to keep costs down. Industry sources have said the new acreage contains large prospects that are shallow and divided by fault zones, similar to Wisting," says Krainer.

"The authorities have paid a lot of attention to our drilling campaign, and even visited the drilling rig, and we have proven that we can operate pioneering drilling campaigns."

Tech Talk

Stacking the technology bricks

Technology development has been high on Subsea 7's agenda for decades. Aligning that mission with a rapidly evolving market is at the top of Thomas Sunde's to-do list, as the company's technology chief tells Russell McCulley in an exclusive interview.

Thomas Sunde's career path at Subsea 7 has taken him from technical and project management assignments to a series of commercial positions, including subsequent stints as vice president of sales and marketing for the company's Asia-Pacific regional division and North Sea and Canada business. The experience prepared him well for the vice president technology post, which he assumed in 2014 amid a restructuring at the company.

"From a Subsea 7 perspective, we've been investing in technology development from day one," Sunde says, citing the company's evolution from diving to subsea heavyweight.

"When the market moved into deeper water, the company transformed itself more towards a diver-less company. We looked at the expansion of our company and continually moved in that direction, and we've developed technology."

Sunde moved into his new post as the company was sharpening its business strategy.

"We acknowledged that we were a technology-driven company, but we weren't properly linking that to the market drivers," he explains. "With an increased commercial view, we transformed what we were doing on the technology side to be purely market-driven. We changed the way we worked."

The company sought input from within its ranks as well as advice from major clients about current and future challenges and the technology needed to address them, adopting what Sunde calls "a more long-term focus on creating value". One target was to engage early with clients in order to optimise field architecture and develop subsea components on the basis of a total system view.

It was an evident area of improvement, he says, even before the current downturn, when the industry experienced what he describes as "the recycling of bids" — the tendency for bids to come in higher than a client expects, sometimes throwing the viability of projects into question.

Subsea 7 opted to "relook at the concepts" and formulate a new approach, he says. "We saw the value, and so did the clients, in early engagement by companies like ourselves, contractors and manufacturers. We assessed the opportunities and entered into two alliances. One was with KBR and (subsidiary) Granherne. That gave us an increased capacity and capability within concept and front-end engineering and design work (FEED). We also established the alliance with OneSubsea, which gave us the ability to take a more holistic, total system view.

"The alliances give us the vehicle to take a total look at the systems being developed, the full architecture, and say, 'can we optimise it?' Which I think is a huge gain in the industry."

Sunde's team also set out to identify "the building blocks, the technology 'bricks' needed to reduce costs and increase recovery rates". An important way to achieve those goals, the company has determined, is to make better use of existing infrastructure.

"The lengthening of tie-backs has a significant impact on future business, as we see it," Sunde notes. "If you look at a mature area where there has been a lot of exploration drilling — say, from a North Sea perspective — if you could double the tie-back length you could more or less quadruple the number of fields that can tie back to one facility."

Subsea 7 also identified the increased costs and flow assurance challenges of complex reservoirs as targets of technology development, as well as life-of-field issues such as asset integrity and data management.

"We took those main challenges and looked into specifics around them — case studies, developments that are on the table today — and asked, 'can we change it?'"

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Photo: Khalil AbuSharekh

MARKET MINDED: Subsea 7 vice president technology Thomas Sunde at the 2016 Offshore Technology Conference in Houston.

Photo: Subsea 7

IN DEPTH: Subsea 7's corrosion resistant alloy-lined BuBi pipe, shown here being deployed at Statoil's Aasta Hansteen development, will be combined with a direct electrical heating system for Wintershall's Maria project.

Focus areas

The exercise led the company to focus technology development in five strategic programmes — riser systems, flowline systems, bundles, subsea processing, and life-of-field and remote intervention.

Subsea 7's deepwater riser portfolio includes decoupled systems such as the single hybrid riser (SHR) and hybrid riser tower (HRT) systems, both deployed at Total's Clov development off Angola, and the buoyancy-supported riser (BSR) system, four of which were installed at the Petrobras-operated Guara-Lula NE project in Brazil (see Upstream Technology 04/2013). The company's coupled systems include flexibles, steel catenary risers (SCRs) and steel lazy-wave riser (SLWR) systems.

Recent developments in the riser programme have focused on the tethered catenary riser (TCR) concept, which consists of several SCRs supported by a subsurface buoy tethered to the seabed by a single pipe tendon connected to a suction pile. The company has also developed new engineering tools, including software that screens a large number of SLWR configurations to determine the optimal solution for a deepwater project. New components include the Plastic Stopper, a polymer structural anchoring point used to secure buoyancy modules on HRT bundles.

For the flowline strategic technology programme, Sunde says, "we set out to make a portfolio of different flowline systems, have them prequalified, have them optimised, so when we then look at the early engagement, the conceptual stages, it allows us to try out different solutions over a tabletop exercise and see what works — what meets the criteria, what has the functionality and what is the best overall cost solution."

Subsea 7's industry partnerships provide crucial help, he says — KBR and Granherne on the conceptual FEED aspects, and OneSubsea for the subsea production and processing systems expertise needed to create a "vertical integration" of subsea services.

"What we're doing is taking the different challenges and developing, individually, the different types of solutions that we have. It allows our design teams, when we look at conceptual work, together with OneSubsea or with KBR and Granherne, to use new technology when developing a field. The main gain here is changing the subsea architecture, simplifying it. There are huge commercial advantages to be gained from that."

On the technology front, Subsea 7 has put a lot of resources into enhancing the performance of both wet-coating flowline insulation systems, dry insulation (as in pipe-in-pipe flowlines) and active heating technologies such as direct electrical heating (DEH) and hot water heating for longer tie-backs.

Recent R&D has focused on electrically heat traced flowline (EHTF) technology. "We've used water heating in bundles before. We've used DEH," Sunde says. "The next step is going toward electrically heat traced flowlines. With a partner, ITP InTerPipe, we've designed a pipe-in-pipe system that has the best thermal performance of any system."

The technology combines high-performance flowline insulation with EHTF to reduce the electrical power required for heating and the associated topside equipment. "The energy consumption is about 10% of DEH," he says. "It cuts a significant amount of cost from the topside point of view, but also from an opex point of view."

The system offers other cost benefits by changing the field architecture.

"In some of the West African jobs we studied, we looked at a typical field layout that involved a loop production flow and glycol injection plant," Sunde says. "The theory and methodology

Photo: Khalil AbuSharekh

"The adoption of new technology is accelerating — there's an openness far beyond what we saw before."

Thomas Sunde, Subsea 7

of any hydrate mitigation was, if you have a shutdown, you'll circulate the flow and inject glycol into it, which is standard and proven.

"In this system, you have a single line, so it removes the loop production. You halve the number of risers, and you also take away the glycol injection plant specifically for that production line. That's where an understanding of the field architecture, the design and conceptual part comes in. That's one of the systems we're developing which I think is a big game changer, even in conventional tieback lengths, and it expands the distances you can achieve."

Subsea 7 has also recently rolled out a mechanically lined reeled pipe, branded BuBi and developed in collaboration with German company Butting. The clad pipe, used at Guara-Lula NE and Statoil's Aasta Hansteen development, will be deployed at Wintershall's Maria project offshore Norway, where the pipe will be combined with a direct electrical heating system (see page 35). The project will mark the first application of reeled corrosion resistant alloy-lined carbon steel pipe with a DEH system.

Pushing limits

Subsea 7 is working on a next generation of its proven pipeline bundle technology, which has been widely deployed over the past 30 years. The technology packages multiple flowlines inside a carrier pipe, which is towed out for installation.

"It's a very impressive system, and it has shown huge value, especially in the UK and the type of infrastructure and challenges we have there," Sunde says. "Now we are taking it to a new level, adapting it for high-pressure, high-temperature (applications) and we are looking into the feasibility of providing bundle solutions in other locations apart from the North Sea."

The company is finalising a test programme for a bundle rated to 220 degrees Celsius (428 degrees Fahrenheit) and pressure up to 20,000psi.

Additionally, "we've looked at extending the length of individual bundles," he says. "The longest we've towed is about 7.5 kilometres long. We're looking at extending that to 15 kilometres on a single tow. That's a big step."

The alliance with OneSubsea, announced in summer 2015, created an opportunity to combine the Schlumberger company's subsea production systems expertise with Subsea 7's subsea umbilicals, risers and flowlines capabilities to create value, Sunde says. Technology development has been concentrated in three early focus areas — integrating subsea processing and boosting within a bundle system, extending the technical limits of long

Photo: Subsea 7

AGILE SWIMMER: Subsea 7 has reorganised its life-of-field business line and increased investment in related R&D, which includes the company's autonomous inspection vehicle.

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Photo: Subsea 7

TOW OUT: Subsea 7 is exploring ways to increase the length of its towed bundle technology to as much as 15 kilometres in a single tow. Pictured is the launch of a 4.5-kilometre flowline bundle for BG Group's Knarr field.

» tie-backs, and surveillance and integrity management of subsea systems and equipment.

Additionally, Subsea 7 has reorganised its life-of-field business line and increased investment in related R&D, which includes the company's AIV (autonomous inspection vehicle).

"We're taking it to the pilot phase and learning from the experience offshore," he says of the autonomous vehicle. In 2015, the AIV conducted a full field inspection trial at three Shell installations in the UK North Sea.

"It's probably the most advanced autonomous subsea vehicle in the world," Sunde says of the AIV. "It has a pre-programmed knowledge of the field and the architecture there. It is agnostic and will inspect and interpret. If it sees something new that wasn't there before, it will make a close visual inspection of it. It's a pretty fantastic piece of kit."

The goal is to reduce the number of tasks that currently require vessel-based operations and crew, he says. In a greenfield development, the AIV, subsea docking station and topside controls would be integrated into the infrastructure design — another example of how early engagement in the field concept and design can produce long-term benefits.

Subsea 7's access to a wide range of technologies has its advantages, he says. By not being wedded to any particular technology or methodology, the company has a lot of leeway to develop appropriate and cost-effective solutions for clients.

"We cover all aspects of installation — we have S-lay, J-lay, reel lay and tow-out solutions. So we're independent of the methodology of installation. And we're independent of a single manufacturer. We're not linked to a single flexible (pipe) manufacturer, trying to sell as much flexibles as possible. We have access, we can buy flexible in the marketplace. That was a strategic decision."

Technology options will continue to grow, and to be refined, he says. While the oil and gas industry has taken some hits in the current slump, it has not abandoned its commitment to innovation. Despite, or perhaps because of, the downturn, "the adoption of new technology is accelerating — there's an openness far beyond what we saw before," Sunde says.

"If you look at the changes made based on technology development over the last three decades, I don't think any other industry can match that.

"I think we often talk ourselves a bit down, saying we're a very conservative industry. I think it's rather that we manage the risk, because the downside is so big if you don't manage it. We're in a position now to manage the risk and still adopt new technology. Execution of our technology projects is key to this, but stepping back from that, it's about understanding where the market is driving us. And that's where Subsea 7 will focus its technology investment."

Photo: Subsea 7

POWER SAVER: Recent R&D has focused on electrically heat traced flowline (EHTF) technology, including a pipe-in-pipe system that combines high-performance insulation with EHTF.

ANALYSIS

Can technology rescue the UK sector? It's all about numbers, writes **Steve Sasanow**.

Unlocking the UK's small pools

The offshore industry has always had a very big wish list of technologies and processes that it wanted to get its hands on. Near the top of that list are low-cost field development concepts for marginal fields.

The parameters of a marginal field depend on the decade in which the investment decision is made and the price of a barrel of oil at the time. Go back a few decades, at a time when the standard price was less than $10 per barrel, and the majority of developments being pursued were in water depths under 200 metres. What constituted a marginal field then looked a lot different than a few years ago, at $100 per barrel and 2000 metres. In one instance, it could be 20 million barrels, in another it could be 100 million.

Whatever the parameters, the definition of marginal is the same — a field where the economic recovery rate is difficult to assess, whatever yardstick is used. What was known in the past as the internal rate of return was an industry secret and different for every company.

Much discussion about field economics has accompanied the existing crisis over the future of the UK sector of the North Sea. The current mantra — maximising economic recovery, or MER, which came out of Ian Wood's 2014 report — has resulted in work being done now under the mantle of the "small pools initiative", carried out under the auspices of the National Subsea Research Initiative (NSRI) and its project director Gordon Drummond.

The initial report on small pools is the result of a pair of freeform discussion forums, dubbed "hackathons", where all and sundry ideas were thrown on the table for consideration. What came out of those events, tapping the brainpower of some 200 delegates in both Aberdeen and London, is not surprising — there is no technological "silver bullet" that can save and revive activity in UK waters, Drummond said. But there are some ideas.

It is of some significance to examine what these "small pools" are — 150 reservoirs holding more than 1 billion barrels of oil equivalent. The report suggested that it would cost $35 billion to develop and operate them, with around $8 billion in revenue generated for the UK Exchequer. That last number is particularly important because it makes the UK government the biggest stakeholder in successfully getting these hydrocarbons to market.

Regional effort

It is possible to improve the economics of these fields, as proven by the results of the survey. At the time the work began, the smallest reservoir that could be developed economically was 11.8 million boe. With reductions in capital expenditure of 25% and 50%, the size could come down to 9.1 million boe and 5.8 million boe, respectively. However, the problem is that these numbers were run at $60 per barrel, a figure that most operators would be thrilled to work to now.

Many of the concepts discussed in the hackathons are not new, but worth revisiting. Mostly they are based around pooled assets and developments. Not much would be developed as standalone projects, but might be produced in some sort of regional scheme.

The origin of such a concept was BP's single-well offshore production ship (Swops) idea from the 1980s. A small floating production storage and offloading system (FPSO) would produce from a field, storing its own oil and then sailing to port to offload before going back to the field and repeating the operation until the reservoir was drained. BP called the vessel Seillean, which is Gaelic for bee, and it was expected to flit around, producing from a hive of small fields.

A good idea but a flawed one, as history proved. Firstly, the time it took to sail to port and offload kept the unit away

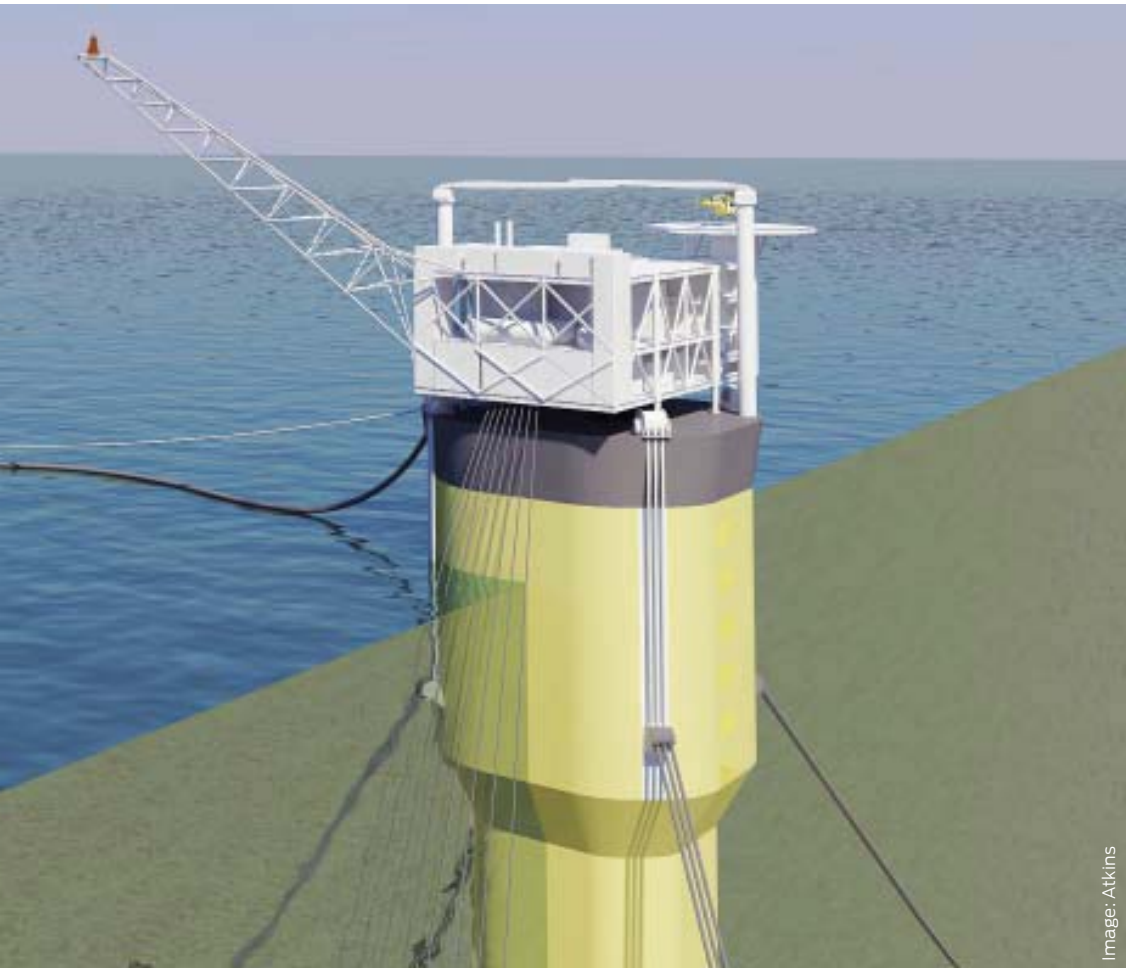


Image: Atkins

Photo: NSRI

STUDY: National Subsea Research Initiative project director Gordon Drummond.

POSSIBLE SOLUTION: A scaled-down floating production, storage and offloading unit, such as the Compact FPSO concept from Atkins, could offer a cost-effective means to produce the UK's small pools.

from its prime purpose, which was production. This also is the antithesis of modern FPSO operational procedure in which the production unit remains in operation even during offloading.

Secondly, BP was probably not the right operator for such a plan as it lacked the portfolio of small pools to make this scheme work in the long term. Also, the vessel employed a rigid riser system, which would have been more difficult and time-consuming to deploy and retrieve than a flexible riser. To be fair, though, flexibles were less widely used at that time than they are now.

Other points to come out of the hackathons will sound familiar — "plug-and-play" subsea technology based on standardised, simplified and modularised systems, a compact FPSO, and remote production with minimal processing and tanker or subsea storage.

While some of this looks interesting, it is difficult to see such concepts being deployed without a change in the thought processes of operators and the government. But the main issue, as pointed out by Drummond, is the market. If these fields could not be developed when the price of oil was at $100 per barrel, then getting them developed now seems daunting.

The other major point is ownership. If a small number of operators owned many of these fields, then getting a consensus on how to develop them might be practical. Over 60 licencees are involved in a total of 210 small pools. How can they possibly agree?

Floating ideas

Several existing technologies, more commonly used elsewhere in the world, do offer some direction. Wider use of "hot taps" to tie-in directly to pipelines, coiled tubing for small diameter flowlines, and non-welded connections offer the potential for reduced capital expenditure.

According to Drummond, there are several regulatory issues that would need to be addressed to smooth the path for this plan. The wide use of subsea protection structures should be reexamined considering the lower level of fishing activity in the sector, which is why much of the equipment has been deployed.

Also, there is the touchier issue of flaring. If some short-term developments were considered in the same light as extended well tests, then it might be possible to economically extract the oil without having to find a gas export solution.

There is also the contentious issue of intervention, a big no-no for successive UK governments. It may be that the Oil & Gas Authority (OGA), the new regulator, might find a way to bring together a group of reluctant licence groups. The NSRI director calls it "collaboration by coercion".

As Drummond points out, there is a long horizon for production in the UK sector based simply on existing and near-term developments, notably in the area west of Shetland. BP, with its Clair/Clair Ridge and Quad 204 complexes, and Total, with Laggan/Tormore and subsequent tie-ins, will be producing for several more decades. It will be new developments, currently under threat, that would continue to keep the sector thriving.

In the end, it will come down to economics, possibly in the form of new contracting strategies. The UK may need to look across the Atlantic to the Gulf of Mexico, where it is not uncommon for infrastructure to be owned by a company totally separate from field licencees. And again, the OGA might have to loosen current regulatory strictures to allow a scenario where a third-party is both contractor and duty-holder of a production facility.

More work needs to be done and it needs to be done now, before even more existing hub facilities are decommissioned, leaving much of the marginal field hydrocarbons with nowhere to go.

SEISMIC

Taking the sting out of time-sharing

Andrew McBarnet reports on a case of innovative thinking that promises major savings in the marine seismic business.

Ask anyone in the business and they will tell you that once under way, a towed streamer marine seismic campaign is never plain sailing. There are so many potential practical challenges to consider such as weather, tides, vessel traffic, environmental restrictions and infrastructure obstacles, not all of which can be taken care of in the survey planning stage.

Yet any disruption to the survey operation that leads to downtime comes at a substantial cost, and the vessel contractor is increasingly being obliged to pick up the tab. More and more 3D surveys are carried out on some form of multi-client basis, where all the risk is borne by the marine geophysical operating company. In such cases, there is no compensation for any delays, whatever the cause. Even today's proprietary 3D seismic surveys tend to be commissioned on a turnkey basis with contractors having to quote a fixed price per square kilometre. Again, this makes no allowance for unavoidable hold-ups of any kind. The only exception to this rule seems to be 4D seismic, where contractors have to date been compensated for downtime out of their control.

Photo: RIL

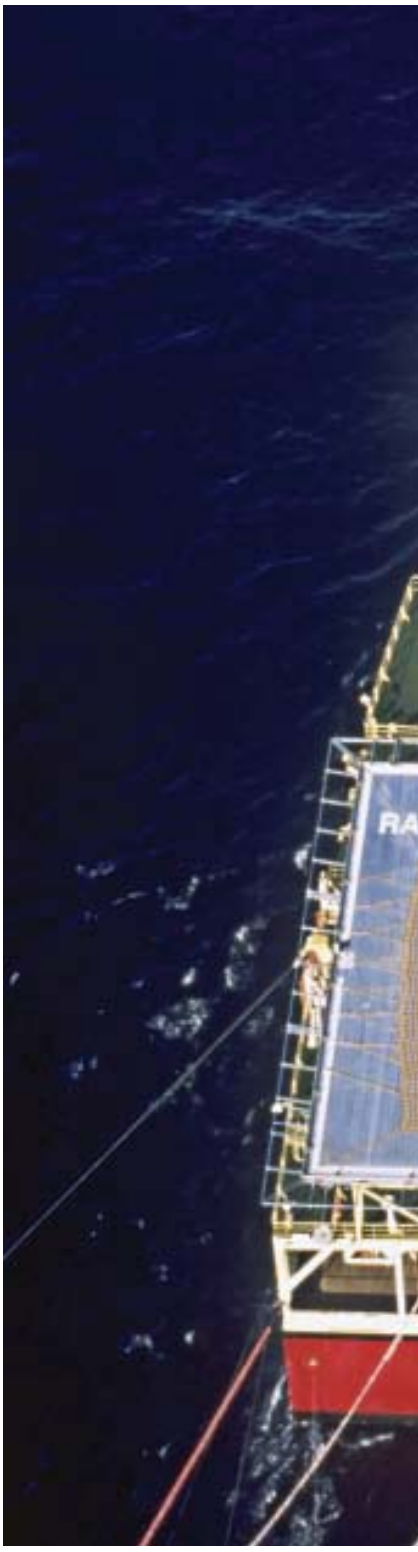
"Industry co-operation... is what our SI solution is all about."

Keith Watt, Reservoir Imaging

It is in this highly cost-conscious environment that Edinburgh-based Reservoir Imaging (RIL) has entered the fray to help develop a software management solution that may save oil companies and contractors millions of dollars a year in lost seismic production time. The company has demonstrated that the need for the long-standing practice of vessel time-sharing between seismic contractors in congested areas can virtually be eliminated.

Time-sharing has long been acknowledged as a necessary evil, but one the industry has been trying to address in recent years. It arises when a number of seismic vessels, or source vessels shooting over ocean-bottom cables or nodes, are working in the same general vicinity. This is a very typical situation in the North Sea. Seasonal weather and accommodation of the fishing industry, especially off Norway, restrict the window of opportunity for seismic projects. Oil companies needing to meet the seismic requirements of their licences, appraise prospects or carry out 4D seismic reservoir monitoring, and service companies undertaking new multi-client projects, are all in action at the same time.

A concentration of vessels in one area is almost inevitable, and the proximity can lead to seismic interference (SI). Data being recorded by one or more towed streamer vessels disturbs the data acquisition of another vessel. To overcome this problem there is a generally agreed time-sharing protocol. The International Association



INTENSE ACTIVITY: The *Ramform Challenger* was one of five vessels working in the Tampen area off Norway last year.

Photo: PGS

of Geophysical Contractors in 2014 updated its time-share guidelines.

The basic idea is that the time available for acquiring or recording data is divided equally among all the vessels affected by SI. This requires a negotiation between the parties involved, including providing proof that the SI is genuine. Anecdotally, the conversation does not necessarily go smoothly. In some jurisdictions, for example in the Gulf of Mexico, "space-sharing" also has to be accommodated. To help mitigate the possibility of SI among operating vessels, active seismic sources are required to maintain a buffer zone of 30 to 40 kilometres.

The net result of time and space-sharing is that vessels involved can experience periods on standby waiting their turn to cover the problematic area. With dayrates for seismic vessels averaging $200,000 — possibly »

» less in the current market — this is a costly and inefficient procedure, acknowledged as such by the industry.

A great deal of the effort in the last few years to tackle the SI problem has been focused on devising processing techniques that can allow the acceptance of a greater amount of interference in the recorded data without the need for time-sharing. The FORCE Geophysical Methods organisation, led by the Norwegian Petroleum Directorate, held a seminar in Stavanger in 2012 where the latest SI attenuation techniques were discussed.

However, even then, researchers, notably in Statoil and contractor CGG, had begun to envision a different approach to reducing the need for time-sharing. It was based on the positioning of each vessel in relation to the others, which is why RIL was invited to the party.

The joint managing directors and founders of RIL, Keith Watt and Gavin Pattison, were originally employees of Concept Systems, the Scottish company that revolutionised the positioning and navigation processing software for 3D seismic surveys, to the extent that its equipment was at one time deployed on 75% of 3D seismic vessels worldwide. Concept was acquired by ION Geophysical in 2004.

Watt, Pattison and two other Concept colleagues established RIL in 2005. At the time they saw an opportunity to resolve some of the positioning issues in the burgeoning market for 4D seismic reservoir monitoring projects. They developed the company's flagship Osprey software mainly to improve the repeatability of 3D towed-streamer seismic surveys over the same area over time.

Their GIS-based solution emphasised thorough analysis of the baseline survey, along with better positioning planning and operation of subsequent surveys. The value of the service was recognised early on by CGG, which became a minor investor in 2006, allowing the company to develop more rapidly.

Over the last decade, RIL lists most of the major oil companies as clients and is arguably the industry's 4D seismic positioning specialist of choice. Right now the 4D market is in something of a slump, according to Watt. "We might see four or five surveys this year in the North Sea. This is about a quarter of what it would be in a good year, and the same applies worldwide. Basically, if companies aren't drilling, there's less demand for 4D."

Fortuitously, RIL started to talk with Statoil about mitigating SI around the time of the 2014 so-called group shoot in the south-east Barents Sea in which 33 companies signed up to participate under the leadership of Statoil. Petroleum Geo-Services (PGS) and WesternGeco were commissioned to carry out the surveys. "It was appropriate, really," says Watt, "because the project was intended to be an exercise in industry co-operation and that is what our SI solution is all about."

Statoil researchers were working on the principle that seismic interference serious enough to call for time-sharing could be avoided by a better understanding of the position of the vessels and the direction of the source noise. Careful management of these two elements could eliminate clashes.

Thomas Elboth and Fakhreddine Haouam, in a paper at the 2015 EAGE Annual Meeting in Madrid, reported on an SI noise experiment using data from a 2D survey in the North Sea. Renaud Laurain et al showed similar results based on the group shoot, indicating that CGG was thinking along the same lines as Statoil.

The CGG authors concluded that proper planning, execution and de-noising would allow two or more vessels to operate at a distance as close as 15 kilometres from each other without significantly degrading the quality of the pre-migrated seismic data. They found that source volume was not a problem, however SI from broadside was more difficult to remove than SI from the front or back of the vessel. Hence their observation "to effectively handle broadside SI, it is necessary to make sure that the SI does not arrive at the same time on consecutive shots". The challenge then was to randomise incoming SI, making it easier for de-noising algorithms to deal with.

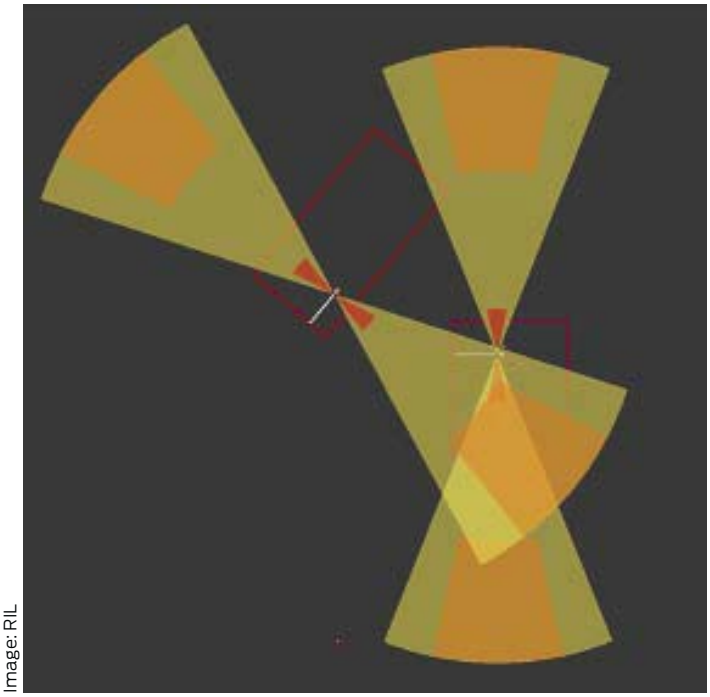


Image: RIL

TO THE POINT: RIL came up with the concept of using noise interference cones, as illustrated, to map where potential seismic interference (SI) between vessels could occur, based on intended survey lines. The information can be used to mitigate the effects of SI. In this mock-up, the vessel on the left will receive SI from the vessel on the right.

NO CLASH: Five vessels working simultaneously in the Tampen area off Norway, including CGG's *Oceanic Champion*, submitted real-time data to RIL to help mitigate SI.

Photo: CGG

Field test

Last year, the Horda Tampen area off Norway saw the first major attempt to put into practice a solution developed with RIL software and personnel. An account of the operation was presented at the recent 2016 EAGE Annual Meeting in Vienna by Renaud Laurin (Statoil), Thomas Elboth (CGG), Jonathan Pollatos (Dolphin Geophysical) and RIL's Gavin Pattison.

The seismic activity in the Tampen area last year was intense, with five vessels needing to carry out surveys and time limited by fishing ground considerations. Statoil had commissioned three proprietary surveys. Two were towed-streamer carried out by CGG's *Oceanic Challenger* on the Visund field and by the PGS *Ramform Challenger* on the Oseberg field. In addition, WGP was operating the *Siddis Sailor* as a source vessel on the Snorre field as part of the field's permanent reservoir monitoring programme. Meanwhile, in adjoining areas, CGG was undertaking a multi-client survey deploying both the *Oceanic Champion* and the *Geo Coral* and Dolphin Geophysical was also active with a multi-client survey.

In normal circumstances time-sharing could be expected. The first key decision in avoiding that possibility was to bring in RIL as an independent third party. With the consent of all the

parties involved, the company's pivotal role would be to use its positioning software to co-ordinate vessel movements. The aim was to either avoid interference completely or make the angle of SI on the shot gather such that it could be easily removed in processing.

Enlisting the co-operation of all parties to accepting the navigation instructions coming from RIL's positioning calculations was an accomplishment in itself. Normal practice is for party chiefs onboard each vessel agreeing to a time-share when the SI occurs. As the Vienna paper authors suggest, this can be "challenging". Certainly the process for establishing a time-share arrangement as described in the IAGC guidelines seems quite elaborate for vessel operators under pressure to complete surveys on time and on budget.

The first practical step in accommodating the multiple surveys in the Horda Tampen area was for the contractors to provide their acquisition plans and, importantly, the speed that could be achieved by the vessels. RIL came up with the concept of using noise interference cones for each vessel to map where potential SI between vessels could occur based on intended survey lines. It then developed a consolidated plan for the survey providers to follow. The speed of each vessel was regulated so that vessels didn't enter the noise cone of another vessel.

During the operation, each contractor submitted their data to RIL in Edinburgh, in the process avoiding any confidentiality issues with competitors. These progress reports allowed real-time adjustments to be made where necessary, supported by two RIL staff offshore. In case of potentially problematic SI, vessels could be requested to slow down or speed up. This manoeuvre broke up the shot-to-shot coherence of the SI, thereby making it easier to attenuate the noise at the processing stage, as envisaged by Statoil and CGG.

"We were very happy with the result and look forward to implementing the solution in similar survey situations as they occur around the world," says Watt. "In the Horda Tampen area, all the seismic data was acquired without SI or with SI in a form that could easily be attenuated by the processors. We got the time lost down to less than 5%, the result of slowing vessels down on some lines to avoid interference and requesting vessels to take their time on some line changes. We're told that in the North Sea summer season 15% to 20% lost time due to SI is the norm."

Examples of genuine improvements in cost and efficiency in the seismic business are few and far between. Companies have been too focused on survival. It is therefore encouraging to come across the type of innovation that RIL and its clients have been developing. U

Photo: RIL

POSITIONING SPECIALISTS: RIL co-founders Keith Watt (left) and Gavin Pattison.

Photo: GE Oil & Gas

Composite flexible riser rollout

GE Oil & Gas has announced plans to manufacture a hybrid composite flexible riser that the company says will weigh up to 30% less than conventional pipe, expanding the operational envelope of flexible risers to water depths of 2500 to 3000 metres.

The technology will replace a layer of steel with a lighter weight carbon fibre thermoplastic material that bonds with an inner polymer layer. The pipe retains the steel "carcass", or inner liner, of conventional riser pipe, as well as the outer layer of steel known as the tensile armour.

The new pipe "will enable certain layout configurations such as free-hanging catenary (risers) to be achieved, which for certain water depths, with the conventional technology, would prove to be quite tough", says Alberto Matucci, global leader of the company's Wellstream flexible pipe division.

The hybrid composite pipe will cost roughly the same as conventional pipe, Matucci says, but will produce a "total installed cost" reduction of about 20% due to faster installation, improved logistics and the potential use of lower-cost floating production units.

Long in development, carbon fibre thermoplastic pipes that include no steel have been used in some subsea applications, such as jumpers and flowlines, and hold promise for riserless intervention. Deepwater risers, however, present challenges for bonded thermoplastic composites, particularly at high-stress connection points.

The new pipe "will not require any change in the critical technology of the end fittings", says Matucci.

GE is installing a production line for the new pipe at its Newcastle manufacturing plant and plans to roll out the first lengths early next year. A 10-inch diameter pipe will be produced for the full qualification process, which could take up to a year. Meanwhile, GE will work with customers to test the pipe in low-risk applications offshore.

Another production line will be set up at the company's Niteroi facility in Brazil, where flexible pipe has been widely deployed in deepwater developments.

"We are moving from the experimental phase to the actual production phase. So the investment we are making in the technology is substantial," Matucci says, adding that the new pipe will be compatible with an expanding range of fibre-optic sensors embedded in flowlines that can transmit real-time temperature and pressure data.

Image: FluidCom

Remote control

Norway's TechInvent will supply its FluidCom chemical injection valve and metering controller technology for two separate projects offshore Norway. The technology uses a "combination of material and thermal effects to markedly improve the chemical injection process", according to the company.

ExxonMobil will install FluidCom technology in a new chemical injection system on the Balder FPSO, and Statoil will use the technology for its new unmanned wellhead platform, Oseberg Vestflanken 2.

FluidCXom uses fully integrated logic controls for local or optional remote communication. The technology also reduces on-site capacity relative to current valves that are larger in size and reliant on additional devices to perform the same function. By working on thermodynamic principles, virtually no moving parts are involved and regular maintenance is not required, the company says.

Photo: Forum

Made in the UK

Forum Energy Technologies has delivered nine subsea pig launch and retrieve (PLR) systems to a project in North Africa. The PLRs, among the largest the company manufacturers, will ship from Forum's Moffat subsea engineering branch in Northumberland, UK, to the development, which is in water depths ranging from 300 to 800 metres.

Forum's PLRs are equipped with remotely operated vehicle (ROV) readable subsea flow meters and ROV operable choke valves for discharge throttling to control the pigging velocity. Forum also developed and manufactured a landing interface from the PLRs to the pipeline end terminator with a horizontal driverless connection system.

QUOTE, UNQUOTE

"This industry has never stacked fifth generation rigs. We don't know how to do it."
Pete Miller, Transocean.

"Today's technology is there. The question is, do you want it cheap, do you want it fast, or do you want it good? You can have two of those."
James Pappas, RPSEA.

"There is an abundance of energy. The question is not will we have enough energy but what kind of energy do we want?"
David Eyton, BP.

"A lot of our projects now are bigger, larger and harder to reach, with more complicated supply chains and other matters that are causing us to rethink how we do things."
Mick Kraly, Chevron.

Photo: Fugro

Current watch

Fugro recently deployed monitoring and measurement equipment to help BP Trinidad & Tobago drill and complete five subsea wells in an area of strong currents. The services included monitoring wellhead motion for fatigue, metocean measurements and positioning services carried out onboard the drilling vessel and three supporting anchor-handling tugs.

To monitor subsea equipment integrity during operations, Fugro supplied its Wellhead & Riser Instrumentation Service (WARIS), which included monitoring on the blowout stack and on the riser, immediately above the lower flex joint. Data was relayed to the vessel by hydroacoustic modems and then transferred to secure onshore storage.

Fugro installed an Acoustic Doppler Current Profiler on the seabed to measure strong currents in the area. The measurements were relayed to the surface vessel in real time using the same hydroacoustic equipment as the WARIS.

BP drilling engineer Anil Saisbhan said the Fugro services "enabled us to realise more fatigue life of wellhead components than was theoretically suggested, as well as to mitigate against operational risk with high currents which occur sporadically in the area".

Durable RFID

A new radio frequency identification (RFID) tag from NOV is able to survive extreme downhole temperatures of -40 to +200 degrees Celsius (-58 to +400 degrees Fahrenheit) and up to 1550 bar (22,500 psi) of pressure. The new TracTag is compatible with NOV's downhole products and has been field-proven to withstand extreme drilling conditions when installed on drillstring components.

The company also introduced asset management software, TracAsset, and an automated pipe tally system with a well site tag reader, AutoTally. Combined, NOV says the system will enable greater capabilities for delivering reliable information and analysis to its customers. The TracTag and AutoTally system will make it possible to read tags as drillstring components pass through the rig floor. Integration of the system into the rig control system will provide drilling hours and critical drilling information down to the serial number of the component.

Image: GustoMSC

Cost-cutting crane

Dutch design and engineering company GustoMSC has unveiled the SmartCrane, a technology that can be retrofitted to existing cantilever jack-up drilling rigs or fitted onto a newbuild design. The company says the new tool increases efficiency by facilitating simultaneous operations independently of any activity in progress on the drill floor.

The SmartCrane also eases material handling underneath the cantilever or between the work platform and drill rig, GustoMSC says.

Enabling a wire line operation away from the drill floor is a "huge advantage in development drilling and plug and abandonment operations", the company says. "The SmartCrane enables wire line through its moveable arm with the hoisting point underneath the cantilever. In this way, wire line operations can take place on one well while development drilling or plug and abandonment operations are going on at another well."

GustoMSC says the crane can help cut rig days required for a plug and abandonment operation by about 10%, compared with conventional methods in which activities such as logging and cementing must be performed in a sequence on one well from the drill floor. The crane has a hoisting capacity of 20 tonnes underneath the cantilever at any position outside the drilling riser, and can transfer containers and equipment from the main deck of the rig to underneath the cantilever and vice versa.

"This is a unique feature that greatly enhances safety and efficiency, as crane access to the well head from the drilling rig is difficult due to the area being blocked by the cantilever," according to the company.

Photo: Saipem

BIG LIFT: Saipem recently established new records with the installation of two gas export freestanding hybrid risers in 2200-metre (7200 feet) water depths off Brazil. One 20-inch riser in particular set records for the largest, deepest and heaviest installation of such systems, as well as what Saipem describes as the longest and heaviest buoyancy tank ever installed (pictured). The operations were carried out using the field development vessel *FDS2*.

Image: Frames

Modular solution

Frames is promoting its modular produced water treatment technology as an effective way rein in development costs. The standardised produced water treatment packages feature modular design, small footprint and low weight combined with minimum engineering and site work, the company says.

The packages are available in a range of different materials depending on fluid characteristics and design lifetime.

The standardised equipment can reduce the oil-in-water content typically from 2000 parts per million by volume (ppmv) to 20 ppmv, Frames says. A package includes hydrocyclones for bulk oil removal followed by a compact flotation to further remove small oil droplets. The package may be extended with a desanding module to process water for reinjection. Comingling of produced water with seawater provides substantial savings on the design of the seawater injection system, the company says.

The packages are available for flow rates ranging from 300 to 1200 cubic metres per hour.

Long lateral

Halliburton and Eclipse Resources Corporation teamed up to complete what the operator believes to be the longest horizontal onshore lateral drilled in the US. The Purple Hayes lateral test well in the Utica shale had a lateral length of more than 18,500 feet and was completed with 124 frac stages in 24 days. The total depth was 27,046 feet, including the lateral extension.

The service company used its complete Frac of the Future fleet, including dual fuel pumps that reduced fuel consumption by 40%, according to Tony Angelle, area vice president for Halliburton. The team set 124 Obsidian Frac plugs and averaged 5.3 frac stages per day, "achieving a North America land record of 26,641 feet in plug set depth", Angelle says.

Along with other efficiencies, Eclipse improved its daily completion rate by 20% over the original plan, lowering its ultimate cost per barrel of oil equivalent, according to Halliburton.

Photo: Tenaris

DRILL DEMO: Tenaris has opened the Rig Direct Academy in Veracruz, Mexico, a training and testing centre that allows customers to witness how the company's products perform in different applications. The $14.5 million facility is equipped to make full-scale demonstrations of new products and developments under adverse and extreme conditions.

Photo: Schlumberger

Power pull

Schlumberger's new MaxPull high-pull wireline conveyance system can pull from 18,000 pound-force (lbf) to 30,000 lbf in wells 40,000 feet (12,192 metres) deep or more. The service company says pairing the system with wireline tractors further improves well access in complex well trajectories while minimising the number of logging runs. The MaxPull system can pull up to 30,000-lbf line tension, which is 43% higher than previously possible.

A customer deployed the MaxPull 30000 system in a deepwater Gulf of Mexico well where job modelling indicated logging tension of 20,900 lbf. The existing highest-pull system of 21,000 lbf did not provide an over-pull capability in the event of tool sticking. By using the MaxPull 30000 system, the customer had the safety margin of 9,000 lbf of additional pull. A sticking incident occurred during a reservoir fluid sampling station. A pull exceeding 29,300 lbf was applied to free the tool string, avoiding a four-day fishing operation and the loss of valuable reservoir fluid data, and saving more than $3 million.

Tougher transducers

UK-based Morgan Advanced Materials has introduced gas flow transducers that can withstand harsh environments subject to extreme temperatures and highly corrosive chemicals, the company says. Its new range of sensors are operable within a temperature range of -50°degrees Celsius to 250 degrees Celsius (-58 degrees Fahrenheit to 482 degrees Fahrenheit). The technology has also been shown to test and measure the flow of cryogenic fluids down to -175 degrees Celsius (-283 degrees Fahrenheit).

The developments are a response to growing demand for compact sensors that remain accurate in harsh environmental conditions. Material selection, coupled with its work in minimising zero flow offset, "will enable Morgan to deliver standard solutions for the wider industrial market or, indeed, for any other application where there is a requirement to accurately measure large quantities of high temperature fluids or gas", the company says.

Image: Morgan

Microbe mapping

Scientists have cracked the genetic code of the marine bacteria that helped "eat" the oil spilled in the Deepwater Horizon disaster, information that could be used one day in oil spill clean-up efforts.

In an article published in the journal Nature Microbiology, researchers from the University of Texas, the University of North Carolina and Heriot-Watt University in Edinburgh describe the genetic pathways of certain species of bacteria that were observed feeding on oil samples from the 2010 Gulf of Mexico spill. The article details the conditions in which the bacteria thrive, what hydrocarbons they consume and how they work in concert during an oil spill.

"We knew that certain bacteria will respond to and thrive during an oil spill and helped break down oil, but we didn't know how this was coordinated," says Tony Gutierrez, an associate professor of microbiology at Heriot-Watt and a co-author of the study.

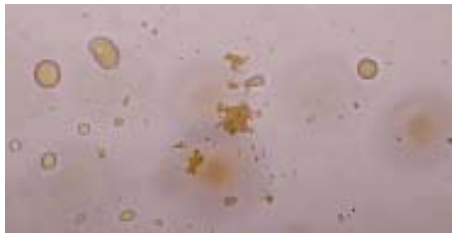


Photo: Heriot-Watt

"By reconstructing the genomes of these bacteria, we've discovered the pathways they use to break down the different types of hydrocarbon chemicals in oil, including some of the highly toxic ones, and the way the bacteria work as a community to degrade the oil."

The team also identified the bacteria that were most effective at different depths during the spill, which were attracted to certain chemicals, and the species that were able to break down the chemical dispersants used extensively in the weeks-long effort to contain the oil.

"The hope is that our findings will allow us to exploit (the bacteria's) oil-degrading potential on a wider scale, such as through more effective bioremediation strategies," Gutierrez says.

NEXT EDITION OF

upstream technology

SPOTLIGHT
Gas technology

Ambitious liquefied natural gas projects have grabbed headlines in recent years, including floating LNG, a long-in-the-works technology that will soon be a reality. Subsea gas compression, another technology years in development, made its debut to great fanfare last year. But for every high-profile project there are many more, less heralded research and development efforts under way to make safe natural gas production economically feasible in a difficult market. This edition's Spotlight on Gas Technology will range from the lab to the field to examine some of the most noteworthy developments.

SPOTLIGHT
Pipelines

Deeper water and more remote locations have introduced a host of challenges in subsea pipeline engineering. Extreme pressures and temperatures test the limits of materials, and flow assurance at great depths and over long distances is a constant concern. Issues around asset monitoring, maintenance and repair likewise add complexity to pipeline design, both offshore and on land. This edition of Upstream Technology examines the various ways the oil and gas industry is addressing today's flowline challenges.

Booking deadline: 2 Sept

The 16 September edition will focus on **Gas technology** and **Pipelines.**

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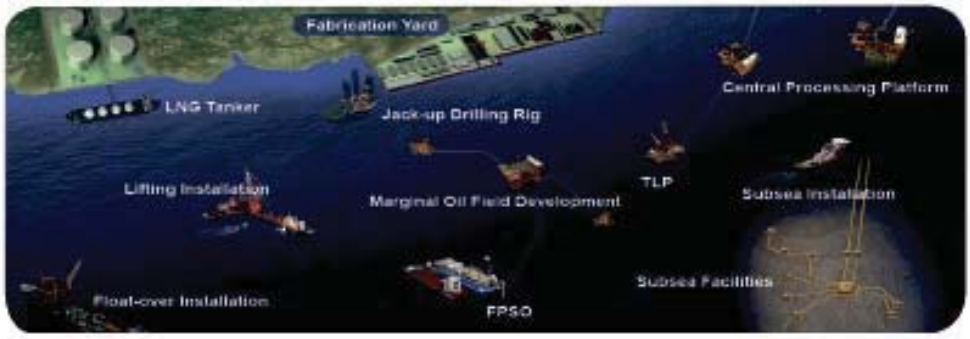

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