

Pioneering Buoy Supported Riser System

Sapinhoá-Lula NE
technical success
see pages 12/13

The many types of innovation at Subsea 7

by Thomas Sunde, Vice President - Technology



In today's low oil price environment, innovation and technology are more important than ever in meeting the challenges facing the subsea industry.

The pursuit of innovation as a platform for future business growth requires commitment, particularly when revenue is reduced and profits are challenged. Subsea 7 is fully committed to building on its track record of successful innovation to drive future growth in its business over the coming years.

Why? Because there is a proven correlation between organisations that invest in this way during leaner times and improved business performance when market conditions once again begin to improve.

Innovation – The Subsea 7 approach
Innovation occurs at the most basic level as a function of general engineering. Problems arise during the course of projects that were not anticipated at the bid stage, and require an immediate resolution. This type of innovation can be viewed as **Reactive** or **Project Driven** innovation.

Innovation driven by the organisation and sponsored by our leadership teams can be viewed as **Proactive innovation**. This is characterised by gradual, incremental improvements, focused on optimisation and standardisation and largely driven at a local level.

How we approach innovation

- **Reactive** - These are project-driven and require a swift response
- **Proactive** - These are innovations which require incremental improvements
- **Process** - These are step change innovations which can produce a revolutionary outcome
- **Strategic** - These are innovations that will deliver solutions to future challenges.

When assessing the emerging and fundamental problems that our clients face, we have to find a way to bridge the gap between what exists and what's required. This is called **Process innovation**. It leads to improvements and operational streamlining through an understanding of how a solution is developed from the current position.

Development of the Subsea 7 Bundle solution is a good example. Having identified a need for subsea tie-backs to be delivered in a more cost effective manner, and utilising our experience in the execution of subsea projects, we engineered a product to meet the future needs and challenges of our clients.

Strategic innovation describes a wider approach over time which recognises that the status quo will not be maintained. Long-term planning and investment is required to establish a position of technology leadership. Innovation from this type of approach will be used to develop new solutions to future challenges.

At Subsea 7 we innovate every day. We work with our clients to embrace their challenges and find new ways to deliver projects in the most efficient way possible. We look outside of our industry for transferable technology. Our goal is to find solutions that sustain the long-term future of the offshore oil and gas industry.

Welcome to the 2015 edition of deep7

Since the beginning of the offshore oil and gas industry, technology has played a fundamental role in supporting the safe and efficient exploration, development and production of hydrocarbons.

This edition of Deep 7 discusses the importance of innovation and how the industry as a whole needs to continue to invest in the development of cost saving and enabling technologies. From the successful deployment of a wholly new subsea technology previously only used in the onshore construction industry, to non-destructive testing equipment used on the Boeing 787 Dreamliner now being tested on subsea equipment, we have examples of how spin-out technologies are increasingly being used across the oil and gas industry.

The one clear theme which binds all of this content is partnership which needs to be central to the industry's approach to sustainability. At Subsea 7 our projects are successful because of the partnerships we have forged with academia, research institutes, and suppliers. This approach means that we can encourage and support the development of knowledge, skills, and technologies which provide us with the ability to successfully undertake some of the most challenging projects in the world.

For Total technology it's the sum of the parts

by Jeremy Cutler, Head of Technology Innovation, Total E&P UK Ltd



At Total innovation is largely focused on technical research and engineering which is linked to the development of technology. More recently it has been recognised that innovation isn't solely about producing technical solutions and it now encompasses the way we work organisationally.

Within the company we formally recognise the efforts of individuals, or more frequently teams, in order to solve problems. We encourage innovation in many different ways and we formally recognise it through our annual Best Innovators Awards. In terms of our external relations, there are ongoing efforts to encourage and foster innovation across industry. Our role in this respect is to effectively identify the best disruptive technologies and to pursue and support those technologies which we believe will make a difference. Our approach is not just about taking a particular problem and finding a solution, but rather identifying technology areas and promoting them through our own R&D, or through the R&D efforts of the industrial community.

The challenge here is to be focused as we obviously cannot support every area of interest. We have therefore transformed our R&D efforts, from some 28 different projects down to eight major programmes which are linked to sub-surface geoscience areas as well as other subjects like Deepwater exploration.

Much of our R&D is therefore undertaken in-house through these eight programmes and it is through these endeavours that we identify different research opportunities. These opportunities may be developed through a joint industry project and by doing this we are looking to leverage our R&D budget with other companies in order to share costs. Another approach might be to pursue a research area through a leading university.

A classic example of how we nurture innovation is in the area of robotics where we have identified the potential for surface based robots to have an impact in our industry. At our test facility in Lacq in the South of France we have established an initiative called the ARGOS Challenge where we have approached industry and asked companies

to design a robot capable of managing a certain number of tasks in hazardous environments. The robots which are being developed might need to be able to climb stairs, or take a reading on a gauge, or turn a valve, or undertake a series of reporting tasks.

Currently we have shortlisted five teams for the challenge which is drawing talent from across Europe and there will be a bursary for the winning team.

This is one way of obtaining support for innovation from outside Total. We are also supporters of ITF, The Industry Technology Facilitator, which has its headquarters in Aberdeen but is spreading across the world. Through our sponsorship of ITF we have the opportunity to take part in different Joint Industry Partnerships (JIPs).

Within Total we promote four key areas of innovation through the Technology Leadership Board which is supported by Philippe Guys, Managing Director of Total E&P UK.

These four areas of innovation include: Intelligent Operations and Maintenance which encompasses integrity, wireless monitoring, smart technologies and robotics; Subsurface Imaging which is linked to the sub-surface definition of structures and the identification of small pools and structures containing oil and gas for future possible extraction within the North Sea; Drilling is the investigation of more cost effective drilling technologies; Long Distance Subsea Tiebacks is an investigation into cheaper and lighter all-electric control systems and how to get power to subsea processing.

These are the four key areas of technology innovation for Total.

We recognise that there are challenging times ahead, but we continue to support our R&D function as our experience shows that we need to be positioned for the upturn and if we cut back now we'll lose the opportunities when they come. This is why we continue to support innovation within our industry, and also study other industries for possible spin-out technologies which may introduce greater efficiencies. Industries such as the aerospace industry, with its long-standing commitment to new, lighter materials, and the nuclear industry with its deep understanding of inspection technologies, remain of abiding interest to us.

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Ensuring risk does not outweigh reward

by Andrew Duncan, Group Leader, Asset & Management Systems, DNV GL



At DNV GL, we are privileged to support innovators who are taking their ideas towards sustainable, commercial deployment. Working so closely with extraordinary people from different types of organisations, at different points in the value chain, we see the challenges they face in making innovation commercially successful.

We note that the number of innovations actively moving towards deployment appears to have increased. The common challenge faced is how to fulfil their vision while being adopted by industry.

Innovation is risky, but it is innovation that is vital to reducing the economic risks faced by the current market situation with suddenly lower oil prices. So now is a very good time to bring whole new ways of doing things to the marketplace – not incremental improvements; indeed the less risky strategy may be to innovate boldly.

However, on any risk scale, innovating boldly can be a gamble, especially if focused on just one area. What's required is a portfolio that gives the return needed in the long run while exposing company's to acceptable risk. A parallel can be seen with financial managers spreading risk across a basket of assets, using 'put' and 'call' options, maintaining the possibility

to buy into success or walk away if the asset is no longer attractive. They also use cost-price averaging to their advantage, spreading investment over time, balancing opportunities.

Differently from pure financial products, an organisation should not lose all its money if an 'Option' (an innovation project that may or may not deliver something valuable in the future) doesn't work out. At worst, the Basic research carried out never leaves humanity poorer in knowledge; something that may yet find a use and deliver value has been developed.

An alternative to the 'gambling' approach of 'Innovating Boldly' might be to stack risk differently, this time in your favour. A professional gambler will work with marginal advantages over the casino, but they will find it very difficult to collaborate with the casino. If an Innovator can collaborate openly with its customers and suppliers, then the risk can not only be shared but, more importantly, the advantages of insider knowledge and shared resources will reduce the total risk.

Knowledge Transfer programmes, JIPs and other collaborations with Oil Majors and Vessel Owners can provide access to resources and facilities otherwise unattainable, which can help Innovators to mature their nascent technologies towards market acceptance. In return, the other party gains access to potential solutions to their problems.

Each party here is an Innovator and will win from the process.

There are ways to reduce the inherent risk of deploying innovation. API 17N and DNV GL's Technology Qualification recommended practice, DNV RP-A203, provide frameworks for the innovator. When such processes are followed, fewer mistakes are made, or are made earlier and therefore more cheaply. If the research progresses to a successful product, then it will not just be more robust and able to fulfil the customers' needs, but also the Innovator will possess validated evidence to support that claim, assuring the stakeholder that they are not being asked to bear intolerable risk (despite the product's novelty).

Bridging the gap from onshore to offshore - DONG Siri project

by Alan Cassie, Project Manager

Transferable technologies are critical to the future development of the subsea industry. When the DONG E&P operated Siri Platform suffered extensive cracking to a part of the substructure supporting the wellhead area and wellhead caisson, a well-used onshore technique was adopted to extend the operating life of the installation.

The novel reinforcement solution identified by the Subsea 7 team was based on the application of cable stay technology in combination with a new seabed support structure for the wellhead area and caisson.

Cable stays are widely used in bridges, but there is no history of their use in the scale proposed for offshore use by Subsea 7. The solution required the platform legs to be stiffened in order to reduce platform motion. This concept reduced the natural period of platform motion – from 6.5 to 6.9 seconds in its damaged condition – to around three seconds. The concept is based on the installation of pairs of cross-braced cables on each of the three faces of the platform, the cables supported at each end by clamps at the top and bottom of the platform legs. Once installed the cables were tensioned to 1,250Te.

The project presented a number of challenges. The complexity of the solution's design was an early issue for the project team. The process was extremely complex, with separate design houses looking at the clamps and cables and the global design of the overall platform. These efforts were separate but related, with changes made in one area having an impact on another. The process was further complicated by fabrication being carried out in parallel with design.

The most significant alteration undertaken to the cable stay design was the introduction of a water tight duct. This required a full redesign of the end anchorages, including a number of entirely new components,

some of which were complex and required specialist manufacturing and testing. This added significantly to the complexity of the cable assembly process. The modified design required the cable ends to be held vertically for over 36 hours while the anchorage ends were sealed with layers of wax and epoxy resin.

Once the design, fabrication and manufacture of the clamps and cables were complete the project team was left with several difficult installation challenges. The size of the clamps used was one such challenge. The clamps weighed around 150Te and included 56 M90 bolts per clamp. The handling of these clamps and the heavy rigging that went with them required a large amount of detailed engineering and analysis to ensure that this could be carried out safely and efficiently. To assist in the installation of the bolts, hydraulically operated bolt racks were designed and fabricated. These significantly reduced the amount of manual handling to be carried out, making the task of installing the bolts both safer and more efficient.

Owing to the weight of the clamps and the attendant issues associated with heavy rigging, complex engineering analysis was required. In order to avoid fatigue issues, the cable design required

that the alignment of the cable between the clamps was very accurate. In turn this required that the clamps were installed to a very tight tolerance of plus or minus 0.15° degrees. To achieve this the clamps were located using pre-installed guide clamps, and clamp headings were measured using survey gyros. Fine alignment was carried out using local rigging before bolt tensioning.

At the time the concept was selected it was anticipated that cable tensioning would be carried out using standard methodology. As the project progressed it became clear that this approach was unsuitable. In response, Subsea 7 designed, fabricated and tested a bespoke tensioning system which allowed for the cable catenary to be removed and an intermediate tension applied in a single stroke.

During the offshore campaign the equipment and procedures worked as planned. The clamps were installed within tolerance, the cable stays were installed and tensioned without damage to the anchorage thread or the water tight duct, and platform natural period reduced from a little over 6.5 seconds to three seconds, with corresponding reduction in platform motion.



Installation of the 150Te clamps to the platform legs required the design and fabrication of hydraulically operated bolt racks, to make the task safer and more efficient for the rigging crew

Aasta Hansteen provides a reel deepwater challenge

by Kjetil Moen, Project Engineering Manager and Maria Eidesvik, Project Manager

Far from land and established infrastructure, the challenge of recovering resources from the Aasta Hansteen field in the Norwegian Sea makes it one of the most demanding engineering projects in the world. As such Aasta Hansteen is an enduring example of how Subsea 7 constantly seeks out new solutions to the challenges it faces. The project teams are multidisciplinary, cross-departmental groups which bring together a unique combination of skills and expertise in order to deliver solutions to complex problems.

The Aasta Hansteen field is located in the northern Norwegian Sea, 300km offshore Bodø in a water depth of 1300m, and is currently the deepest development in Norwegian waters.

The field is being developed with three subsea production templates, tied back to a SPAR FPSO via mechanically-lined (BuBi®) flowlines and clad Steel Catenary Risers (SCRs). Gas export will be through the POLARLED pipeline which is to be connected from the field

to the Nyhavna gas terminal on the Norwegian west coast.

The infield pipeline system consists of four 12" Outer Diameter (OD) thermally insulated BuBi® pipe flowlines with a total length of 16.5km. One flowline runs from a template to template location, while the other three connect the template location to the SPAR platform and are tied in via 12" OD thermally insulated metallurgically-clad pipe SCRs each measuring approximately 2000m. The pipeline system also includes coating, fabrication and installation of one 14" OD corrosion protection coated carbon steel pipe gas export SCR, approximately 2,000m long.

The flowlines and the SCRs will be fabricated at Vigra Spoolbase in Norway and installed by the reel-lay vessel *Seven Oceans*. The SCRs will be laid down temporarily for subsequent pull-in and hang-off after tow-out and mooring of the SPAR platform. The 12" OD SCRs are welded to the flowlines via tapered transitions.

Welding of the SCRs will be completed by Subsea 7's Pipeline Production Team (PPT) using a mechanised procedure for mainline welding of both 12" production SCRs and 14" Gas Export SCRs using Gas Metal Arc Welding (GMAW) and a Cold Metal Transfer (CMT) process for root pass and Pulsed Gas Metal Arc Welding (PGMAW) for hotpass fill and cap. The welding process is adopted for both fatigue sensitive areas and non-fatigue sensitive areas. This welding procedure was originally developed for the Sapinhoá-Lula NE project and subsequently refined during a preliminary welding programme at the Global Pipeline Welding Development Centre in Glasgow.

The work involved two main elements, refining the weld quality experienced on Sapinhoá-Lula NE by incorporating PPT's latest developments in welding technology and updating the welding programme to deal with the specific requirements of Aasta Hansteen's large diameter (323.9mm and 355.6mm OD) and heavy Wall Thickness (WT) (28.6mm) SCR pipe.

The SCRs include fatigue zones at the top and in the touch-down areas where stringent defect criteria apply, together with cap sanding requirements in order to obtain the necessary fatigue performance. The specific requirements to the fatigue zones involves stringent AUT acceptance criteria with a maximum allowable defect height of 1.5mm, zero weld repairs, so any rejects have to cut-out and re-welded and weld caps fully removed and 100% post removal surface inspection by Magnetic Particle Inspection (MPI) and Dye Penetrant Inspection (DPI).

Performance in this area was verified by a number of fatigue tests containing seeded welding defects, as requested by the client, a relatively novel approach within the industry.

(Installation methodology includes licenses from Statoil Petroleum AS).

Aasta Hansteen has number of milestones, including the world's largest SPAR FPSO with Steel Catenary Riser (SCR) system and reeled installation of BuBi® mechanically lined pipe

BuBi® pipe reel-lay installation

During the load-out and installation of the BuBi® pipe, the pipeline was water filled and pressurised to avoid wrinkling of the liner. The minimum required pressure had been determined through detailed design and technical qualification.

Technical qualification of the 12" BuBi® pipe for reel-lay installation with DNV is to be performed in parallel with the project, building on previously approved qualifications of the 8" to 10" pipe.

Operationally, the water filling and pressurisation is to be obtained by

using a water filling spread, mobilised onboard the pipe-lay vessel with connection to the pipeline on the reel. The pipeline will be filled from the lay vessel for each stalk pull, with a set of high differential pigs creating the barrier between what will be approximately four Bar internal pressure during the stalk tie-in welding. Specifically designed plugs will be installed at the stalk end and on internal pressure in the order of 30 to 40 Bar, which is to be established before each stalk pull takes place.

Based on lessons learned from the Sapinhoá-Lula NE project, a solution for an improved water filling system onboard the lay vessel has been

developed. Connection to the reel is via a slip ring system which allows for permanent connection of the water filling spread on the vessel deck to the pipeline and thereby enhanced control of the pressure without having to stop reeling operations. The system also allows for recirculation and containment of a finite amount of the fresh water and MEG mixture.

ULTRA® pipeline coating

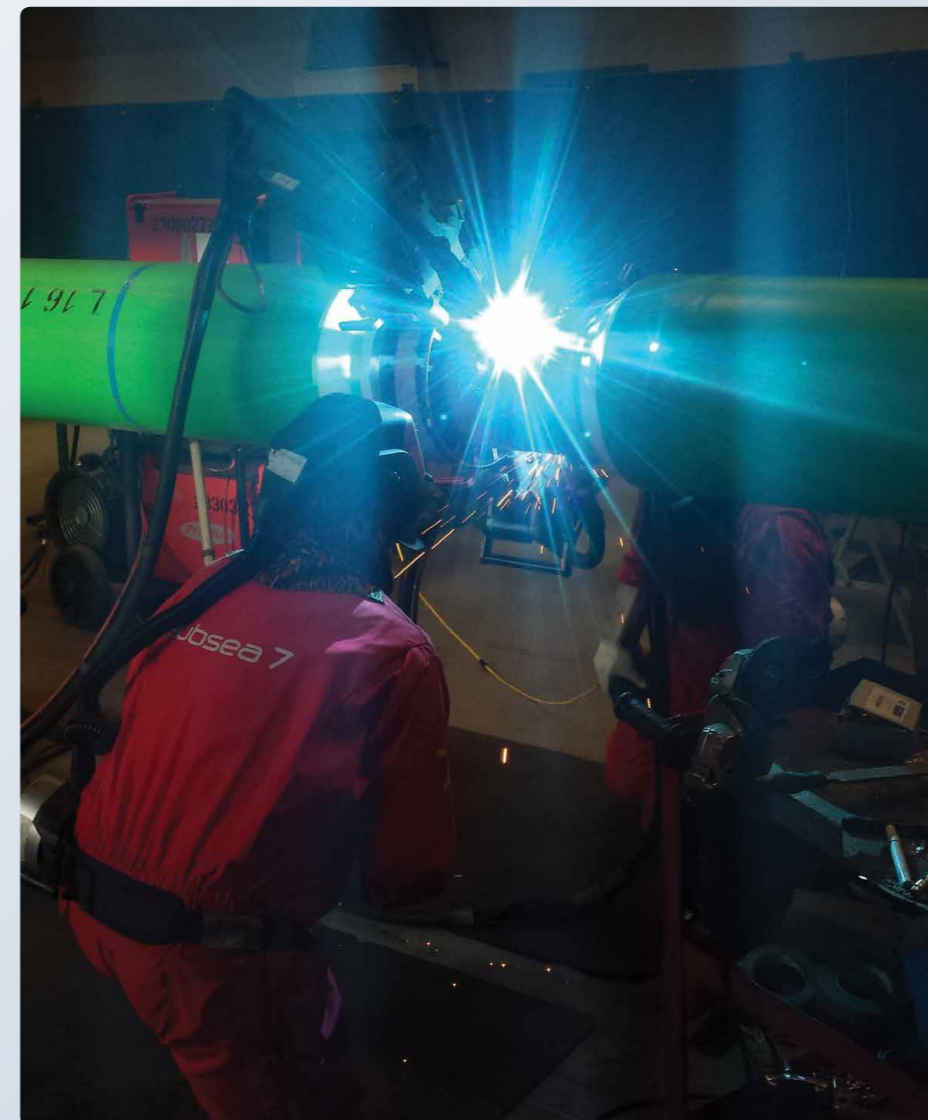
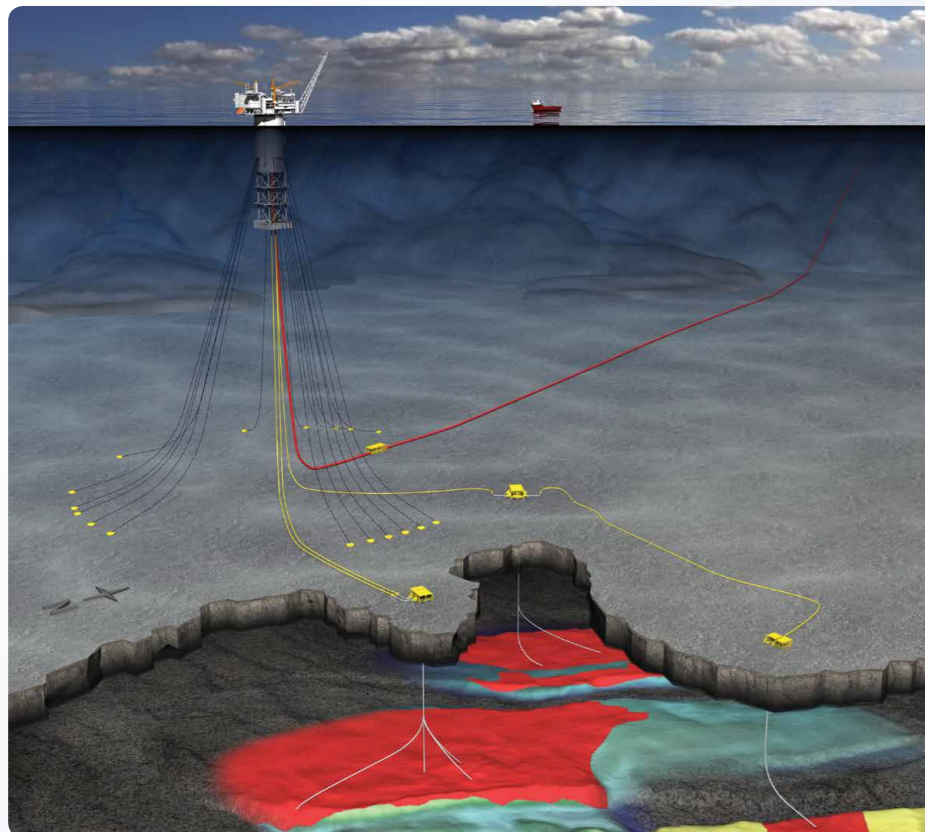
Aasta Hansteen is the first Subsea 7 project to use the ULTRA® insulation coating system developed and provided by Bredero Shaw. The ULTRA® coating provides significantly improved thermal insulation properties over the conventional PP Foam systems. For the flowlines with a U-value of 4.0 the reduction in coating thickness of ULTRA® compared to PP Foam is from 80mm to 50mm corresponding to approximately 40% reduction. This means that more product may be stored on the pipelay vessel reel.

Controlled lateral buckling

The temperature of the flowlines during operating condition is such that control of end expansion and lateral buckling is required. End expansion control is achieved by conventional rock dumping solution whereas controlled lateral buckling is obtained by distributed buoyancy installed on the pipeline.

There are in total five lateral buckling zones over the four flowlines, with each buckling zone consisting of 25 buoyancy modules distributed over a length of 100m.

Distributed buoyancy provides a cost effective solution compared to sleepers and rock carpets and provides low stress levels which makes the solution suitable also for BuBi® flowlines.



The welding process on the Aasta Hansteen project was originally developed for the Sapinhoá-Lula NE project and subsequently refined during a preliminary welding programme at the Global Pipeline Welding Development Centre in Glasgow.

Material gains – innovation in epoxy pipeline repair

by Kenneth Bryson, Mick Fowkes, Paul Booth and Christopher Mock, Subsea 7

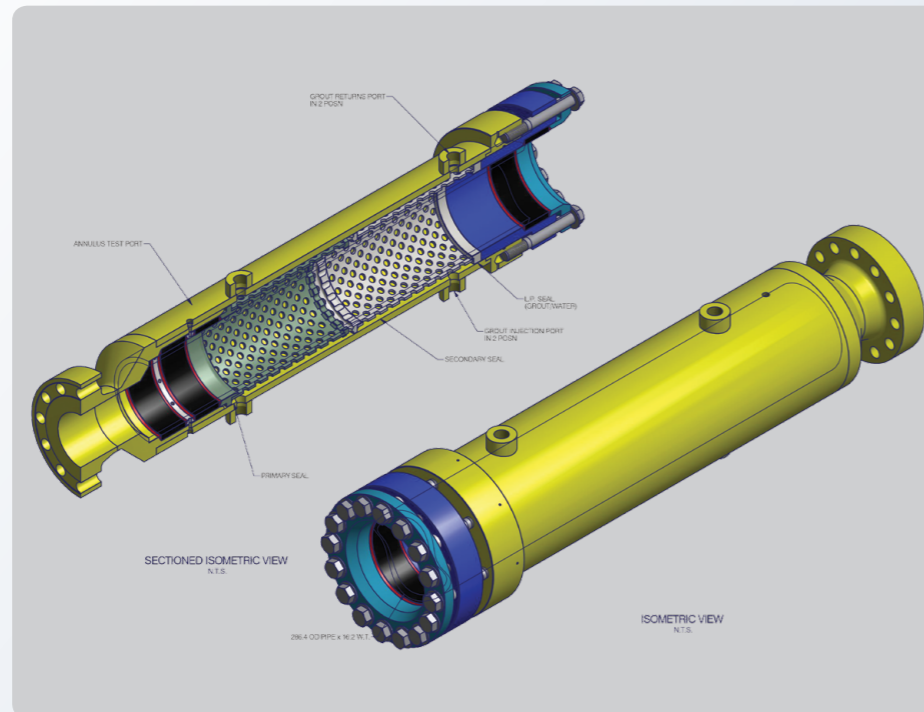
Submarine pipelines are the arteries of the oil and gas industry with pipeline technology having advanced dramatically over the past 30 years and projects that were once mere dreams now a reality. Today, breakthroughs in materials science are helping to further improve the integrity of offshore pipelines while reducing ongoing costs.

Despite advances in pipeline technology significant challenges remain, ranging from problems presented by pipe laying mechanics, buckle propagation, interaction with sandwaves, and surface tie-ins. Faced with these ongoing challenges epoxy repair technology is set to make deepwater pipeline repairs lighter, easier and more cost-effective.

Subsea 7's epoxy hardener and micro glass sphere aggregate provides a robust way to repair hairline cracks and cavities while eliminating the possibility of weakening caused by shrinkage. The reduction in curing time, to just 24 hours compared to seven days for cement grout, also offers greater Inspection, Repair and Maintenance (IRM) cost management. With a wide range of applications, including pipe branch connection, or tie-backs, valve replacements, by-pass for pipeline repairs and blocked removals, its versatility is most evident when deploying Subsea Grouted Tees (SSGT) and Pipeline Repair Systems (PRS).

In particular, the principal advantages of epoxy resins come to the fore when it is used in live interventions, or hot tap applications. This is a technique which allows a connection to be made without shutting down whole systems and venting gas, resulting in significant technical, schedule and installation benefits.

Furthermore, as epoxy technology offers a significant reduction in component lead time, simpler construction and a reduction in the use of support vessels,



A 3D diagram of a epoxy filled slide-on connector

clients are able to minimise the need for upfront CAPEX expenditure for a contingency system.

Subsea 7's epoxy repair solutions are lighter, cheaper, easier to install and imposes fewer requirements on the underlying pipe. In 2006, Subsea 7 began collaborating with Advantica, formerly the R&D Division of British Gas Corporation, to extend the use of epoxy hot tapping equipment for subsea pipelines.

The key benefits of Subsea 7's epoxy grout solution

- Compressive strength
- Shear strength (concentric rings)
- Adhesive & cohesive strength
- Tensile bond strength
- Tensile Modulus
- Minimal volumetric changes after curing.

To control the above physical properties, and to allow epoxy grout to be used at any depth, a seabed grout

injection system has been developed to provide a repeatable process and produce consistent grout quality under subsea installation conditions. Control of grout quality includes:

- Testing curing strength
- Ensuring all critical gaps, cracks and crevices are filled with grout.

Subsea 7 is currently working toward industrialising the further development of epoxy repairs, replacing most if not all conventional clamp, tee and connector requirements.

One important type of epoxy repair is the SSGT which can be used in a number of live intervention, or hot tap scenarios. Some unique key features offer added operational benefit such as offset acute angles, double branches and K configured branches. Possible applications include pipe branch connections (tie-backs), valve replacements, by-pass for pipeline repair and blockage removal.

With regard to epoxy based PRS, most current solutions are based on hyperbaric welded repairs, mechanical repair clamps, or connectors, and repair spools. Repair hardware and installation tools are well established and available from a small number of providers. For deepwater repairs, performed remotely by ROV, the repairs are much more challenging and involve investment in specialist equipment.

Advantages of epoxy technology in pipeline repair

Subsea 7 is increasingly seeing clients take a more proactive approach to pipeline repair, often specifying and procuring elements of a pipeline repair system as a contingency against future problems.

With client engagements it is important to minimise CAPEX expenditure for a contingency system, while ensuring that it is possible to carry out a repair within a predetermined timescale should the need arise. The use of epoxy technology allows significant reduction in CAPEX due to reduced lead times, simpler construction, reduced vessel requirements and overall reduced installation schedule.

Key advantages offered by epoxy technology for pipeline repairs include technical, schedule and installation benefits. Technical advantages include the ability to transfer load from a damaged pipeline section, quickly and efficiently. This is particularly advantageous in situations where there is wall thinning caused by internal or external corrosion and where the use of a mechanical clamp type connector is impossible because of the strength of the force imposed by the mechanical gripping system.

In situations where pipelines require major repairs and cut-out and repair spools cannot be deployed, the advantages are more significant. This is

because the equivalent epoxy solution is much simpler, requiring only seal setting and no grip deployments.

Epoxy technology compares well when equated to mechanical grip repair solutions such as ball bearings which are squeezed into a pipe thereby generating hoop stress and effecting a repair. Weight versus pipeline diameter does not increase in the same ratio as that for conventional mechanical connectors.

When performing repairs remotely in deepwater the size and weight of the repair hardware has a significant impact on the installation vessel, deployment equipment and handling methods. The use of epoxy technology permits a smaller, lighter solution leading to overall reduced installation costs, even when accounting for the epoxy injection process. Most significant gains will be achieved for major cut-out repairs where the use of epoxy couplers offers the greatest size and weight advantage over equivalent couplers, or flange adaptor connectors. Ultimately, this leads to a reduction in the specification requirements for installation while offering a bigger operational weather window for deployment vessels. It also permits the use of an infield support vessel rather than larger, costlier offshore construction vessels.

Qualification Programme

Significant test data exists to support and provide confidence that epoxy based repairs provide the required high level of integrity once installed.

Many tests and qualifications have taken place, including seals, epoxy, shell, branch and injection. These tests included laboratory based material and component testing, full scale testing and infield tests to ensure the highest quality repair is delivered.



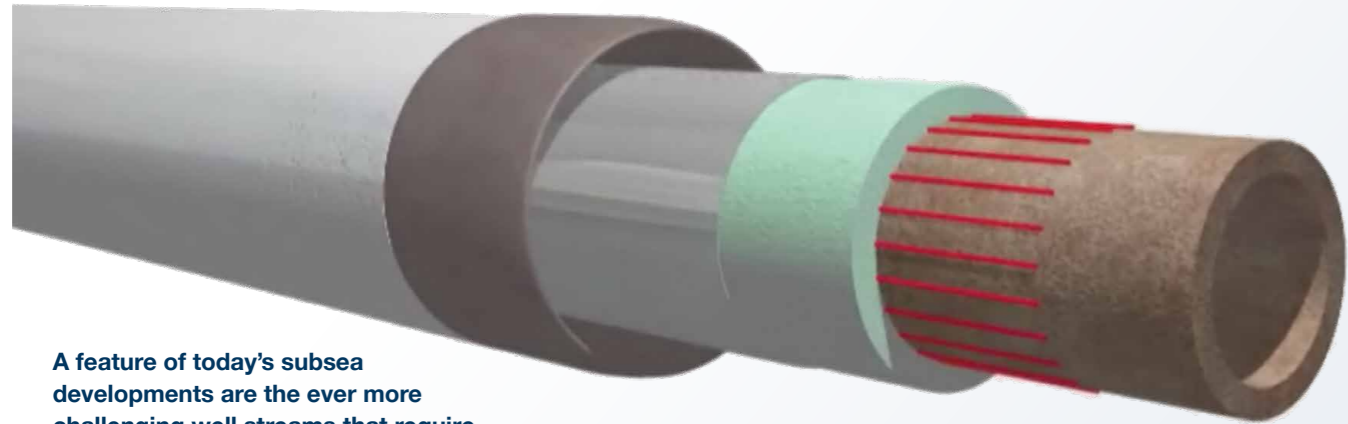
Epoxy technology compares well when equated to mechanical grip repair solutions

Epoxy repairs – the way forward

Subsea 7's epoxy technology is an important development with many applications in pipeline intervention and repair. Deployed more rapidly from smaller vessels, it can significantly lower the costs of field extensions or damage remediation. For contingency repair systems, both the initial investment and the cost and time to repair are reduced. Considerable testing has been carried out and gives confidence that epoxy systems can restore damaged pipelines to their original specification, or carry out modifications which meet current industry standards. It represents a significant new Life of Field offering to Subsea 7's clients and pipeline operators around the world.

Missing flow without a trace

by Neil Brown, Technology Manager - Norway



A feature of today's subsea developments are the ever more challenging well streams that require advanced solutions for the flow assurance issues faced by operators. The need to limit uncontrolled wax and hydrate formation over longer distances presents a technology and engineering challenge that cannot be economically addressed using standard pipeline solutions.

In response, Subsea 7 and ITP InTerPipe (ITP) have been working closely with other technical partners to commercialise the Company's Electrically Trace Heated Pipe-in-Pipe (ETHP) system, which has been developed for installation with the reel-lay method.

ETHP within the subsea environment

Subsea 7 has an established track record of PIP design, fabrication and installation, with more than 40 projects executed to date by different installation methods, including J-lay, S-lay, towing and, most recently, reel-lay. The ETHP solution builds on this track record, using existing technology, and standardised, market ready components where possible.

The PIP mechanical design is an evolution of the Enhanced PIP system previously developed in collaboration with ITP. This enhanced system combines high performance Izoflex™ insulation with reduced pressure in the PIP annulus to deliver a market leading thermal performance.

The technologies developed specifically for the ETHP system include an electrical heating system and

components, bulk head penetrators, electrical and fibre-optic wet-mate connectors and a fibre-optic monitoring and communication system.

The ETHP system was initially qualified in a passive mode, without heating elements. Proof of concept for the complete ETHP system was then performed in collaboration with DNV. A further qualification program for field specific designs is currently on-going and is expected to be complete within the 2015 - 2016 timeframe.

Meeting the challenges of the subsea world

In developing the ETHP solution, Subsea 7 collaborated with clients to take a holistic approach to the production system design. This process is managed by a dedicated ETHP Task Force within Subsea 7, a multi-disciplinary team, capable of performing early phase engineering and concept studies through to detailed design.

The insights gained collaborating with clients have been instrumental in defining the functionality and operating philosophy for the ETHP system. As a result, the system provides industry leading thermal performance combined with power requirements that are significantly reduced compared to competing technologies.

Some examples of the value of early operator engagement include qualification of the electrical system for always-on operation, as well as the ability to isolate wire groupings. These features provide clients with the freedom to adapt heating requirements in response to a changing production profile throughout the life-cycle of the field. It also provides a level of redundancy in the electrical system design that is not achieved by competing or established technology.

From the system level perspective Subsea 7's ETHP system provides the ability to actively vary the heat input to the pipeline system, meaning that it is possible to narrow the range of arrival temperature at the downstream end of the pipeline in a manner that is not possible with other solutions.

The resulting product is a system that is capable of delivering a significant reduction in CAPEX requirements compared to competing technologies, improved reliability and operational flexibility over the life cycle of the field.

Subsea 7's ETHP technology lends itself well to a large variety of applications and can enable or enhance cost-effective architectures for deepwater subsea developments.

Mechanically Lined Pipe is a qualified success

by Grégory Toguyeni, Principal Welding & Materials Engineer

Market demand remains strong for High Pressure, High Temperature (HPHT) pipeline materials which are resistant to severely corrosive environments. Subsea 7 continues its pioneering development of Mechanically Lined Pipe (MLP) technologies, with an extensive DNV approved qualification programme which led to the demonstration of its fitness for service when installed by the reel-lay method for flowline and Steel Catenary Riser (SCR) applications.

Subsea 7 has recently expanded the diameter range of its reeled MLP with a 16" outer diameter pipeline. This qualification involved full scale reeling simulation to confirm that no wrinkling of the liner occurred, and a complete set of mechanical and corrosion testing to ensure that the product was completely sound post installation.

Another key milestone reached in 2014 has been the qualification of the reeled MLP for in-service conditions involving a combination of high pressure, high temperature and lateral buckling. In instances where the conditions during the operation of the pipeline drives the design requirements due to high pressure, temperature conditions, or complex seabed topography, occurrences of free spans along the line and lateral buckling may develop.

In such conditions, there is a need to demonstrate how the MLP is able to withstand the various thermal and mechanical loading modes during its operation and throughout a series of full and partial shutdowns.

In particular, shutdowns are the source of various cyclic loadings, namely: pressure, temperature and axial strain cycling. These can lead to a type of fatigue cycling usually referred to as low cycle fatigue, in contrast to the high cycle fatigue characteristic of SCRs. The high cycle fatigue loading has already been qualified for reeled MLP in earlier phases of the development

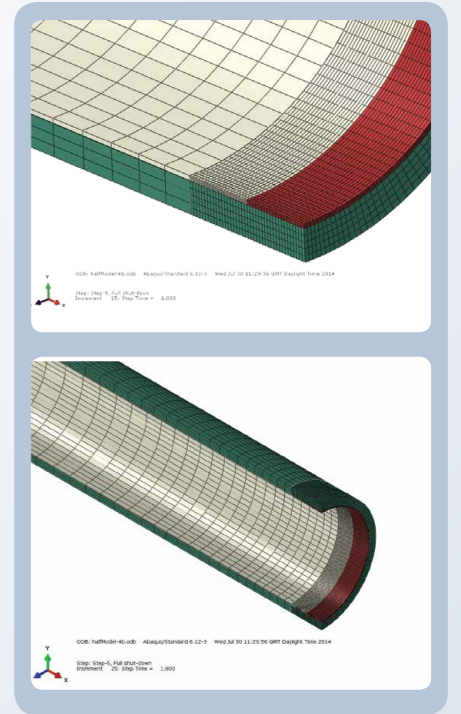
programme by performing full scale resonance fatigue tests up to a stress range of 200MPa.

When the stresses experienced during the fatigue cycling are above the material yield strength at first load, failure can occur at a number of cycles much lower than if the material was stressed in its initial elastic domain. In such instances we would refer to 'low cycle' fatigue.

On an MLP, high values of local stresses can be experienced at the pipe end triple point where the Corrosion Resistant Alloy (CRA) liner is welded to an overlay weld. At this point, also referred to as a seal weld, the strain combined with thermal cycling can generate a local bending moment that, if of sufficient amplitude and number of cycles, could produce failure of the liner and exposition of the carbon steel outer pipe to the corrosive environment.

First, a detailed Finite Element Analysis (FEA) model was created with a fine meshing at the pipe ends where the seal welds are located. Loading steps corresponding to project specific HPHT operational conditions were then applied using the Abaqus® software. This allowed an extraction from the FEA of the local axial stress range at the seal weld for all the different shutdown scenarios.

In parallel, bespoke small scale fatigue test specimens were designed from a production BuBi® pipe (a type of MLP produced by Butting). The pipe material used was first subjected to cyclic pre-straining up to two per cent strain, simulating a 14" diameter pipe lined with alloy 625 installed by the *Seven Oceans* reel-lay ship and then aged at 250°C for one hour. The specimens were then tested in fatigue at the actual stress range predicted by FEA. The testing was conducted at an elevated temperature of 105°C using calibrated servo-hydraulic machines and special high temperature strain gauges



FEA model with fine meshing at the pipe end seal weld

attached close to the seal weld as a means of controlling the applied loads.

At a nominal axial stress range at the seal weld of 592MPa, the average number of cycles to failure was above 27,000 cycles, thus far exceeding the number of anticipated shutdown cycles during the design life.

This programme has demonstrated the suitability of the reeled BuBi® pipe for operational conditions involving HPHT and lateral buckling without the need for more expensive clad pipe sections at the buckle zones.

Subsea 7 continues to maintain its unrivalled project experience using reeled MLP with the installation of the 70km of Sapinhoá-Lula NE SCRs completed successfully in 2014, and on the Statoil Aasta Hansteen project (see pages 6 and 7) with the deployment of 16.5km of 12" reeled BuBi® pipe progressing well.

Sapinhoá-Lula NE - a deepwater technical triumph

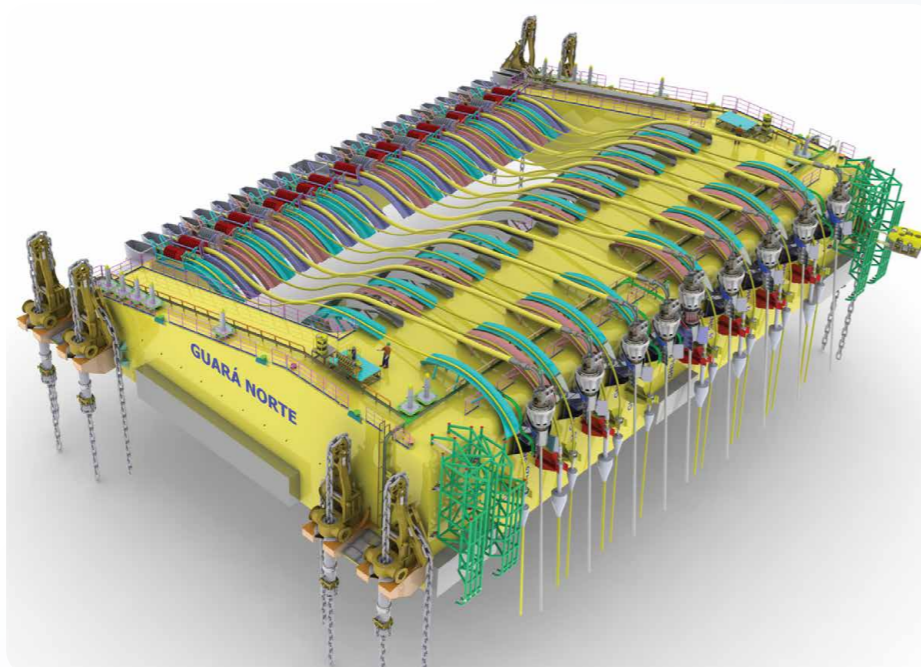
by Ivan Cruz, Senior Product Manager and Daniel Karunakaran, Chief Engineer, Technical Authority

In 2011 Subsea 7 was awarded a milestone Subsea Umbilical, Riser and Flowline (SURF) contract by Petrobras for four decoupled riser systems to be installed in the Sapinhoá-Lula NE fields located in the Santos Basin, offshore Brazil. It is the largest engineering, procurement, installation and commissioning (EPIC) SURF contract awarded to date in Brazil.

The project's technical focus was the installation of four very large 2,800Te submerged buoys approximately 250m below the surface. The system was designed to accommodate 45 risers/umbilicals for each field in a small area in a decoupled arrangement. Subsea 7's scope was specifically twenty-seven 3.9km steel catenary risers of which eighteen were 7.5-inch production lines, three 9.5-inch water injection lines and six 8-inch gas injection lines.

Petrobras and its partners selected this Buoy Supported Risers (BSR) system as the most effective solution for the project. In order to meet the system's performance and installation requirements, various innovative technologies were required. These were:

- An efficient method to install corrosion resistant alloy (CRA) mechanically lined BuBi® pipe by the reeled-lay installation method;
- The development of the Angular Connection Module (ACM). This unique engineering capability greatly simplified buoy hardware by minimising the number of connections and potential leak paths;
- A fit for purpose 400Te tension capable riser installation tool, allowing for the reliable deployment of 27 SCRs;
- A state-of-the-art fracture mechanics engineering assessment for plastically strained pipe joints made of alloy 625 welds;
- A novel tethered tensioned mooring system, similar to that for Tension



The BSR buoy top side with guiding chutes, moonpool and flexible jumper installed with ACM

Leg Platforms (TLPs), but using spiral strand cables and chains for installation simplicity and to achieve the necessary dynamic performance;

- A tether based tensioning system capable of withstanding top angle variations associated with the buoys natural offsets and the potential length variations of the almost two kilometres long tethers;
- A bottom connector device to simplify connections to foundations.



Angular Connection Module (ACM)

The combined result of all these innovations, some incremental and resulting from existing technologies, and others entirely new and breakthrough, gave rise to the complete BSR system. The following provides in greater detail profiles on the Angular Connection Module (ACM), and developments in tether design and materials for BSR mooring.

The development of the Angular Connection Module (ACM)

The creation of the Angular Connection Module (ACM) proved integral to the BSR system by connecting the flexible jumpers to the pre-installed buoys. Because of the large number of risers installed, the buoys can take up different positions. The ACM allows connections to be made at misaligned angles of up to 15°, reliably and safely, thereby reducing offshore hook-up time.

Within the BSR system the introduction of the ACM reduced fluid flow to a single interfacing point, thereby saving cost and enhancing reliability by eliminating further potential leak paths.



Front cover : the BSR in the field prior to installation

Tether adjustments

The main requirement for successful BSR mooring was to use tether adjustments to stabilise and position each buoy. The principal challenge associated with this work was the selection of an appropriate tether material, thereby helping to ensure that the axial stiffness was preferred in order to balance the desired tension adjustment, and to keep neighbouring tethers closely together while dealing with the initial slackening during fabrication and installation. Although steel air filled pipe is a commonly used material for Tension Leg Platforms (TLPs), a moderated decrease in the axial stiffness was preferred, thereby creating a simple top tension between adjacent tethers and length adjustments. A significant increase in tendon stretch, applied while the BSR was in vertical motion, would not have been an acceptable approach because of the high possibility of misalignment and damage to the system.

Table 1 – Tether material comparison

Potential tether materials			
Tether type	Sheathed Spiral Strand Wire	Polyester	Steel Pipe
Diameter (mm)	101.6	184.15	304.8 OD / 20.05 wall
Air Weight (kg/m)	57.6	21.9	140.5
Wet weight (kg/m)	45.2	5.5	65.7
Break Force (Te)	1178	1000	1009
Stiffness (MN)	1017	265	3710
Length (m)	1890	1890	1890
Long (Te)	400	400	400
Stretch (m)	7.3	28.90	2.0

Another equally important technical issue which needed to be addressed was the submerged tether weight, which had the potential to minimise the impact on negative buoyancy and dimensions. Different materials for the buoy mooring lines were considered in some detail. The three options considered were:

- Polyester fibre ropes
- Steel tendons
- Sheathed spiral strand wires (SSW)

The polyester lines offered the lightest option. However, this material can lead to stretching and the need for longer chain tails and operational time to adjust the length. Additionally, there is a potential for long term creep under service load, which might pose a risk to the buoy's dynamic performance.

The steel tendons have a stiffness of more than three times the SSWs. This is attractive for the theoretical in-situ

analysis and the ready understanding of a simple technology. However, the installation is more complex, requiring welding offshore and the stiffness would require a more complex operation to adjust the lengths to ensure proper load distribution and ensuring the buoy was level in its submerged position. Additionally the top connector was more expensive.

The sheathed spiral strand wire has a long track record in other mooring systems and was found to meet all the requirements for 27 years of service life. The stretch is no excessive, but is sufficient to help minimise the effects of length measurement tolerances, is comparatively easy to install offshore including locking of the lines in the connectors at the required point.

After considering all of these factors it was concluded the SSW was the best option, for both long term service reliability and from an installation point of view.

The BSR solution – overcoming deepwater challenges

Introducing new technology into complex offshore exploration and production projects is always challenging given the stringent requirements of safety and reliability, together with the inevitable constraints posed by commercial imperatives. Innovation in the upstream sector is frequently driven by the need to secure access to hydrocarbons from reservoirs in ever more challenging deepwater environments.

Sapinhoá-Lula NE, with reservoir clusters in the Santos Basin proved to be an extreme example of such challenges. The innovative BSR concept was a demonstration of how the early engagement of many different companies and the eventual adoption of numerous new technologies, produced breakthrough solutions in one of the world's toughest field environments.

From airline pipe dream to subsea inspection solution

by Bob Lasser, Imperium Inc., with John Rhodes and George Gair of Subsea 7

An ultrasound inspection technology used to examine the airframe of the Boeing 787 Dreamliner is now being used to test the boundaries of underwater inspection capabilities. Subsea 7's Life of Field business teams have been looking at other industries to source technologies and new approaches which can yield benefits to the discipline of through-life support within the subsea environment. One such area is the aerospace industry which is now using state-of-the-art ultrasonic imaging developed by US technology company, Imperium.

Founded in 1996, Imperium supplies handheld ultrasonic devices to non-destructive testing (NDT) professionals. Imperium's range of cameras are based on well-established technology and used widely within the aerospace industry. In 2013 it was selected by Boeing to be included in the Boeing 787 inspection procedure.

The cameras generate real-time two-dimensional images of subsurface anomalies. Internal corrosion and cracks can be simply and quickly imaged without extensive training, calibration or equipment.

A simple setup procedure allows internal defects to be visualised, providing instantaneous data on the thickness and overall integrity of a structure. The technique is based on optical practices, using a large area source of ultrasound, a beamsplitter, an acoustic lens set, and a two-dimensional imaging array.

The output of the patented approach uses a real-time C-scan imager and the output is extremely high resolution.

Ultrasound technology in the subsea world

Subsea infrastructure is installed, often with little or no redundancy, in an environment that is both challenging and expensive to work in. Within this challenging environment Subsea 7

continually explores ways to maximise the effectiveness, efficiency and quality in the delivery of its subsea inspection services. One new way in which efficiencies in underwater inspection can be introduced is through the use of ultrasound technology. Imperium's Acoustocam is a real-time Cscan, high-resolution, large field of view, ultrasound camera based on the company's patented Digital Acoustic Video (DAV) technology. The Acoustocam has a complete set of tools for weld and corrosion inspection including an A scan sensor for thickness measurements and off-line software for post processing. Reducing in-water time and removing specialist technicians and operators offers a significant saving to clients. Any improvement in inspection technology that can reduce the time it takes to perform these and other inspection tasks is of significant value.

DAV technology is similar to that used in a standard video camera. As a video camera uses a flash, a lens, and an optical sensor, the DAV uses an ultrasound source, a lens for beamforming and a 120 row by 120 column detector array for receiving and processing ultrasound. The DAV



Figure 1a Pipe STD with Acoustocam

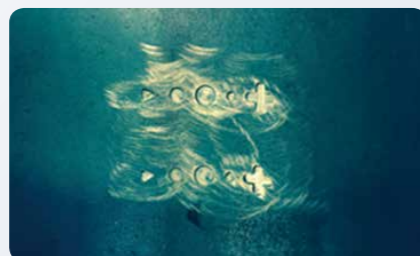


Figure 1b Inner Wall FBHs

technology incorporates a beamsplitter to collimate ultrasound in order to allow the lens to focus at multiple depths.

The Acoustocam testing programme

At the time of publication the camera is being tested in Aberdeen. In figures 1a and 1b Imperium's pipe standard is shown with flat bottomed shapes milled into the inner wall. In figure 1a the Acoustocam is shown mounted on the pipe with magnetic wheels for stability and positional information.

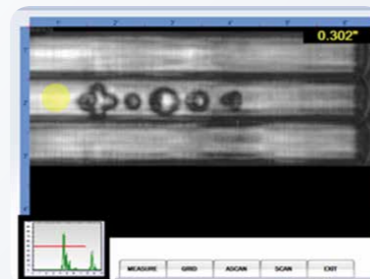


Figure 2a Pipe Standard Scan

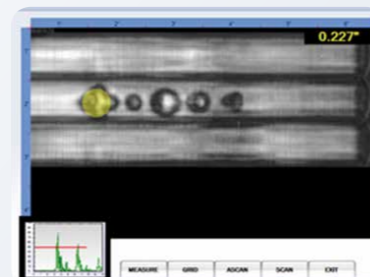


Figure 2b Pipe Standard Scan

Scans are shown in figures 2a and 2b where multiple individual Cscan frames are stitched together into a single large display. The pipe sample is of 0.300" wall thickness. In figure 2a the thickness of the back wall is shown with A-scan presentation and in figure 2b the thickness of the flat bottomed cross is shown. Note the resolution and clarity of the stitched Cscan images.

Another test sample is the 0.75" steel plate with a 5mm layer of polypropylene placed on top. Polypropylene is one of the coating materials used by Subsea 7 and imaging through the coating is the preferred process rather than removing the coating altogether in order to perform the inspection.



Figure 3 V Notch

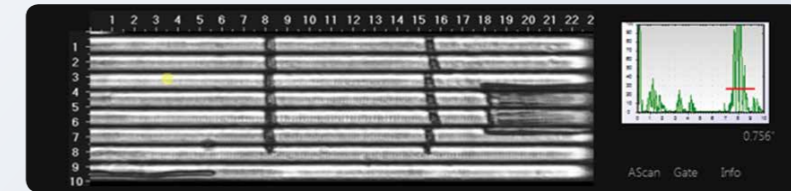


Figure 4a Steel Plate Scan with Backwall

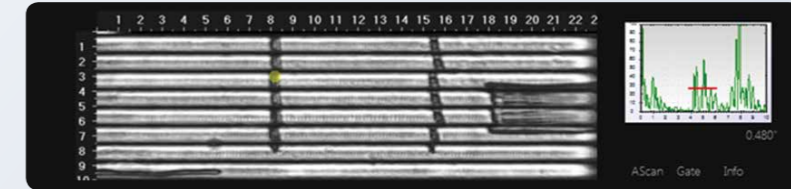


Figure 4b Steel Plate Scan with V Notch area highlighted. Yellow thickness reading directly over notch area

Figure 3 shows a V notch milled into the back wall of the plate. The next images were taken with post processing tool, the Imperium Analyzer. In figure 4a a thickness reading of the back wall is included in the scan. In figure 4b a thickness reading of the V notch is included with the scan. Note that on the A-scan presentation in figure 4b the two peaks form both legs of the V notch are seen.

In summary, preliminary results indicate that the Imperium DAV technology can be translated from aerospace to the subsea environment. The ease of use and clarity of imagery result in a device that requires minimal training and produces reliable, repeatable data that is easy to interpret.

The primary objective is to deliver one system that replaces the many devices currently in use, providing high resolution data faster, with reduced reliance on skilled human intervention.



Global opportunities for Pipeline Bundle technology

by Martin Goodlad, Strategic Technology Manager, Pipeline Bundles

Subsea 7 has designed, fabricated and installed Pipeline Bundles, or towed pipeline production systems, for more than 35 years, with 75 Pipeline Bundles manufactured to date.

In recent years, Pipeline Bundles have been accepted as a technically and commercially attractive solution that allows difficult fields to be successfully developed. Bundle technology presents significant potential for extending existing facilities or opening up new developments, and its global future and prospects for further innovation are equally exciting.

The technical benefits driving the wider use of this technology are well understood:

- Highly-efficient insulation systems, heated Pipeline Bundles using hot water, or Electrical Trace-Heating.
- Design/construction method allows full system integration testing onshore allowing fast hook-up and commissioning offshore; low stress installation method by Controlled Depth Tow Method (CDTM) minimises stress and fatigue on internal flowlines.
- Design of Pipeline Bundle cross-section/system allows expansion at both ends, reducing build-up of axial forces, reducing the need for intermediate expansion spools, and allowing efficient design for High-Pressure, High-Temperature (HPHT) field developments.
- Pipeline Bundles eliminate requirements for specialised installation vessels (reel-lay, S-Lay, J-Lay, and heavy lift) by using readily available vessels, and incorporating subsea structures within the towed Pipeline Bundle System.

Today, Subsea 7 has begun the work to migrate Pipeline Bundles away from their proving ground origins in the North Sea, to other challenging parts of the

world. When one looks at other markets and regions, such as Brazil and the move to 2000m+ water depths, and the Gulf of Mexico with water depths of 1000m, the difficulties of weight and corrosion posed by deeper water becomes the principal concern for Pipeline Bundle design. The deeper the water, the more demands on the collapse resistance of the carrier pipe and the internal nitrogen pressures.

The greatest water depth for a Subsea 7 Pipeline Bundle design to date is 410m within BG's Knarr development in Norway. It is expected that this can be extended in the future by use of alternative buoyancy arrangements.

At deeper water depths a Pipeline Bundle will begin to take on a different look given the challenges posed by greater water pressures and stability issues. Key to Bundle design in deep and ultra-deepwater will be the control of the bulk and weight. The adoption of composite materials will be increasingly important to diminish the effects of corrosion.

Subsea 7 presently has a target date of 2018 to incorporate composite flowlines within a Bundle. As a starting point Subsea 7 is looking to deploy a composite water injection line as a means to evaluate composite use on a production line.

Considerations for wider Pipeline Bundle deployment around the world

Deepwater

In deep and ultra-deep waters, a Bundle could begin to look very much like a Hybrid Riser Tower (HRT) with a central core or buoyancy pipe incorporated into the design. In such environments Pipeline Bundles would need to be able to resist greater collapse pressures in the water. The current design does not allow the structure to be thick enough, therefore alternative design methods, such as solid buoyancy and temporary

buoyancy would be used to make the Bundle considerably lighter.

Composites

Weight reduction, greater design integrity, fatigue resistance, strengths and corrosion resistance are all principal benefits offered by introducing composite materials in Pipeline Bundles. Composites began life as a weight reduction measure, but in recent years the need for corrosion resistance has come to the fore. Cost reduction is also an important issue as composites can be cheaper than many high performance metals, considering the whole project cost.

The increasing demands on materials to meet future technical requirements for risers, flowlines, spools and components such as stress joints is providing the impetus for Subsea 7 to take a closer look at composite applications in these more demanding environments, particularly in the context of Pipeline Bundles and their future use.

Technical specifications to address the requirements associated with pressure, temperature, corrosion and fatigue are stretching the suitability of established metallic and non-bonded flexible options. Composite solutions for Pipeline Bundles include bonded composite thermoplastic pipe.

Shallow waters

Pipeline Bundles have been installed in shallow waters previously on Maersk Dan (42m) and Hess South Arne (60m). In these water depths the on-bottom stability is crucial due to the environmental effects. This has previously been achieved through either filling the pipeline bundle annulus with heavy grout/barite slurry or partial rock dump. The on-bottom stability requirements for the Pipeline Bundle system are currently assessed based on separate design codes for pipelines and structures.

Subsea Processing

by Sigbjørn Daasvatn, Strategic Manager for Subsea Processing

Pipeline Bundles offer one of the best platforms for the installation of subsea processing facilities. The ability to install large structures and complete all onshore testing and commissioning of the systems significantly de-risks the installation.

The pipeline section of a Bundle, between the towheads and the towhead structures, can be used for the processing of hydrocarbons, thereby turning a Pipeline Bundle system into a processing facility. This was demonstrated in a recent Cold Flow study for Statoil. The first phase of the R&D study has been completed to demonstrate the further ability to incorporate the subsea processing elements within the Pipeline Bundle towheads.

The incorporation of Subsea processing within a Pipeline Bundle system is not new technology. Previously Subsea 7

installed large towhead structures and incorporated elements of extant subsea processing infrastructure.

The Total Jura Pipeline Bundle installed in 2008 incorporates two subsea HIPPS units and cooling spools in recoverable modules, allowing the units to be recovered to the surface for maintenance and repair. The BG Knarr Bundle installed in 2014 incorporated cooling spools at both ends of the Pipeline Bundle within the towheads, along with diverless connectors. For this project the Pipeline Bundle system was designed as an integrated system, whereby the cooling role of the cooling spool was balanced with the insulation requirements of the pipeline sections in order to optimise the system and to better support client requirements.

The Jura and BG Knarr Towheads are the largest installed to date at 525te and 580te respectively. The new launchway design, installed at the Wester site in 2014, will allow towheads up to 700te to be launched from the facility.

Arctic waters

It is well understood that the exploration and future

production of oil and gas projects in the Arctic is considered more technically challenging than in any other environment so far.

Demanding offshore environmental loading conditions could potentially influence the design and installation of Pipeline Bundles with principal areas of concern including Pipeline Bundle configurations, thermal insulation, and trenching requirements.

A new way forward will be researched and specific requirements for stability of the Pipeline Bundle as a system will be developed. This will involve close multidiscipline collaboration between structures, bundles and geotech and incorporate experimental testing as well as numerical and detailed computer analysis.

Additionally the analysis will be benchmarked through the use of 'as installed' measured data from Pipeline Bundle systems. This work will reduce the reliance on secondary stability mitigation for Pipeline Bundles in shallow water and open up further market opportunities.



Tackling hidden challenges of the Arctic environment

by Dwayne Hopkins, Research & Development Engineer

A collaboration study between Subsea 7 and C-CORE, an independent not-for-profit R&D corporation that creates value in the private and public sectors by undertaking applied research and development, has looked at the potential for Pipeline Bundle burial through a six-month desktop study.

It is certain that in future Arctic developments, especially in Alaska and the Beaufort Sea, there will be a major requirement to bury Pipeline Bundles in order to avoid interaction and damage from icebergs. The study will look at the challenges and benefits of transferring this technology to the Newfoundland offshore environment, which is now seen as a test bed for subsea technologies planned for use in harsher and more remote locations within the Arctic region.

The study will help Subsea 7 bring this technology to the Canadian market as well as enhance the Company's Pipeline Bundle portfolio. Feasibility and numerical calculations will help determine the benefits and challenges of Pipeline Bundle burial.

Pipeline Bundle burial will depend on regional geotechnical properties that influence thermal conductive and methods of burial.

The study will be carried out through four principals:

Task 1: Investigate the type of required trench for Pipeline Bundle burial and optimisation. Investigation will use lessons learned from previous C-CORE buried pipeline studies, including the Pipeline Response to Ice Gouging (PIRAM) study.

Task 2: A study on benefits and drawbacks of buried Pipeline Bundles in terms of construction considerations, leak strategies, heat recovery and flow assurance.

Task 3: Economical analysis of single trench multi-pipe in terms of technology readiness, technical issues, operational and life of field costs.

Task 4: Results, discussions, and conclusions:

- What are the existing gaps in knowledge and technologies?
- What is the best practice for the Grand Banks based on the available technologies and knowledge?
- Determine future studies required.

Objectives

Since the burial of pipelines in the Grand Banks is a serious consideration to protect Pipeline Bundles from iceberg scour, it may be beneficial to place multiple pipelines and umbilical lines within a single trench. In this case the use of a Pipeline Bundle could prove to be beneficial. To evaluate the use of Pipeline Bundles for this purpose, this study will investigate their efficiency in terms of trench construction, backfill, required U-values, field inspection, maintenance costs, and any other additional criteria identified during the course of the study.

Rationale

Developments of offshore oil fields in Arctic and Subarctic environments present unique and challenging obstacles that, on their own or in a combination, create the need for unique oil and gas development solutions. Some of these obstacles include:

- Sensitive environment
- Remote operations
- Insufficient nearby shore infrastructure
- Extreme low air temperatures
- Short seasons for surface operations
- Presence of ice in various forms
- Permafrost and hydrates

Of the aforementioned challenges, the presence of ice is a formidable

obstacle for the Arctic. It can have a detrimental effect on the seabed by scouring the sea floor up to depression depths of in excess of 5 metres. These unique ice loading conditions could potentially influence the design and installation of offshore pipelines. Areas of concern for offshore pipelines include, but are not limited to: Pipeline Bundle configurations, thermal insulation, and trenching requirements.

Alaskan Beaufort Sea operations have helped establish a baseline for future Arctic development with buried pipelines in a piggy-back configuration in near shore oil fields. Although installed during the winter season by trenching the seabed through the ice, the Alaskan experience has shown the viability of using Pipeline Bundle technology as a solution for buried pipelines in Arctic / Sub-Arctic regions.

Newfoundland and Labrador provides an ideal location to support professionals working in and learning about the Arctic. Iceberg Alley, an area stretching from the coast of Labrador to the northeast coast of the island of Newfoundland, has led to the creation of world class research and facilities.



This has also proved to be the case with Subsea 7's team leading investigations into the deployment of Pipeline Bundles. Subsea 7 has been able to tap into local skills and knowledge and draw upon a unique environment which shares many features which are common to numerous Arctic locations.

Building for the future

by Stuart Smith, Vice President, Asset Development



The Seven Arctic benefits from a 900t offshore crane

Seven Arctic

The Seven Arctic Heavy Construction Vessel is now rapidly taking shape in dry-dock at Hyundai Heavy Industries.

Meanwhile at Huisman's factory the 600Te VLS and the 900Te crane is progressing well on schedule.

When delivered in 2016 the Seven Arctic will allow Subsea 7 to effectively execute ever more complex projects for our clients. The main operational differentiators include the following:-

- The 600Te VLS is amongst the largest in the world and will allow laying of large diameter flexible pipes in deepwater



One of six HIMSSEN 9H32 engines being installed

Main crane

- Type; Huisman Rope luffing Knuckle boom crane; hook travel 3,000m
- 300Te at 45m radius; 600Te at 30m radius; 900Te at 20m radius
- 40Te whip hoist; maximum radius 60m
- High lift mode; maximum 50m under-hook clearance ; maximum Radius 52m
- Hoisting speed single fall; 40m/min full load; 80m/min reduced load
- Hoisting speed twin falls 20m/min on full load; 40m/min at reduced Load
- Active Heave compensation; operational stroke 8m for single line
- Deep water lowering; wire rope spacer and deep water block

Auxiliary Cranes

- Aux 1; 100Te at 15m radius; AHC; hook travel 3,000m
- Aux 2; removable; 25Te at 16m radius; AHC; hook travel 3,000m

- The 7,000Te underdeck carousel gives unrivalled capability to lay the longest umbilicals and power cables associated with long step-outs, power from shore, or developments with seabed processing

- The highly versatile and capable rope luffing knuckle boom crane is ideally suited to a range of tasks including installation of increasingly heavy manifolds and other seabed structures; very long spool pieces and other equipment requiring high lift heights; in addition to more routine lifts from anywhere on the deck

- Large strengthened deck area and vessel stability suitable for general project load of around 4,500Te at 5m above deck

- Suite of auxiliary cranes for effective multiple deployments to the seabed and manoeuvring complex systems for hook-up at depth.

The crane was recognised as the Innovation of the Year at the annual Offshore Support Journal conference.

Seven Kestrel

Subsea 7's latest DSV, the Seven Kestrel, left the security of dry-dock and floated out into the harbour at Hyundai Heavy Industries yard on 15 February 2015. She is now at an advanced state of construction with all main machinery and main components of the dive system such as the launch and recovery system, saturation dive chambers, gas storage system and environmental control units already located on board.

Work is continuing to progress well with the focus now changing to aspects such as finalising the electric cable pulling, hook up of the dive system and outfit of the accommodation, and is all on schedule for operations in early 2016.

The saturation dive system is an 18 man system rated to 300m incorporating twin bells, twin hyperbaric life boats, two six man chambers, two three man chambers, four wet-pots, two TUP chambers and a semi-automatic control system. The main system is laid out ergonomically on one deck with side mating bells to maximise efficiency.

She has been specifically designed for North Sea operations as a capable and cost effective unit and complimentary with other DSVs and construction vessels in Subsea 7's fleet.



The Seven Kestrel photographed soon after its float out event in February 2015



Subsea 7's new DSV, the Seven Kestrel, will feature an 18-man twin bell saturation diving system

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