

# OILFIELD TECHNOLOGY

EXPLORATION | DRILLING | PRODUCTION JANUARY 2015



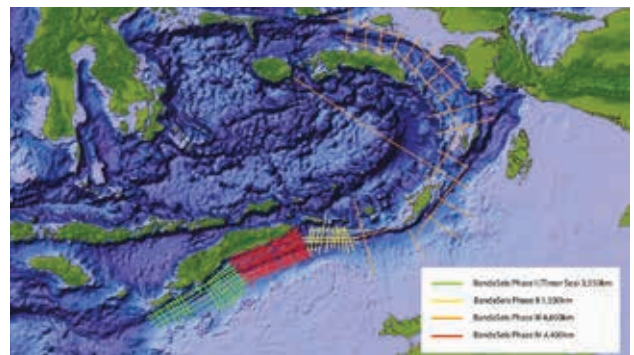
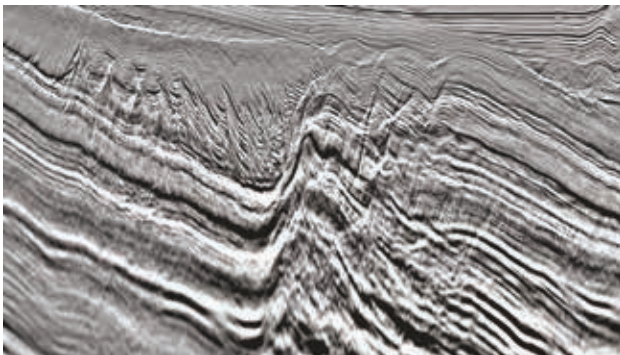
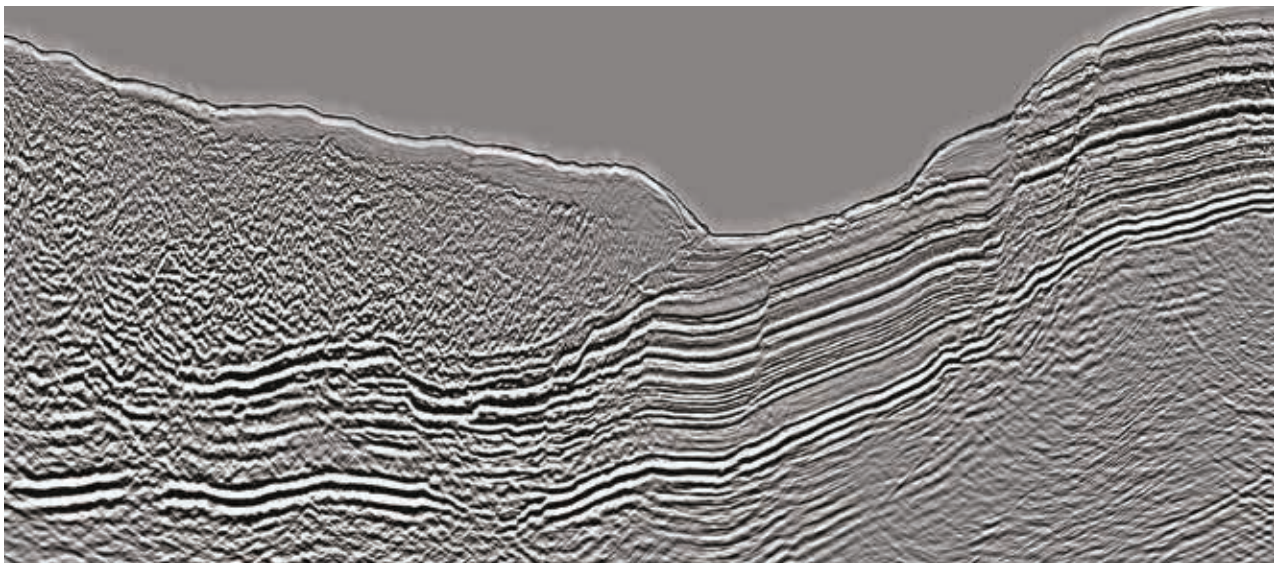
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# World news **January 2015**

## Expro secures US\$200 million contract with Statoil

The international oilfield services company, Expro, has secured a significant Europe CIS (Commonwealth of Independent States) contract, providing fully integrated well testing and fluid sampling services for Statoil Petroleum AS in the Norwegian Continental Shelf (NCS).

Starting on 1<sup>st</sup> January 2015, the initial 4-year contract is valued at US\$200 million with options to extend for a further 6 years.

The contract will include the provision of downhole tools, gauges, tubing, surface well testing, rig cooling and subsea services. This is complemented by a range of fluid sampling services, including downhole samplers, surface sampling and specialised analysis and metering services. This extends across the exploration, appraisal and development activity for Statoil's mobile offshore drilling units and fixed platforms within the NCS.

Expro's new US\$10 million base, due to open in Tananger, Norway this summer, positions the company well to support this new contract. The 19 000 m<sup>2</sup> facility consolidates Expro's three current locations in Stavanger, and is complemented by existing offices in Bergen and Haugesund. The 10 600 m<sup>2</sup> workshop has the capacity to rig-up four well test packages, and service a further six, simultaneously.

COO, Mike Jardon, commented, "We are absolutely delighted to continue our long-standing relationship with Statoil, a cornerstone operator in the Norwegian Continental Shelf, providing long-term activity over the coming years.

"This contract award is an important achievement for Expro. We have proven our position as the leading well flow management company in Norway, with a firm focus on delivering safe, high quality services to our customers." ■

## Eni awarded Croatian exploration license

Eni was awarded an exploration license within the Croatian First Offshore Licensing Round. The license is referred to Block 9, which is situated in the Adriatic Offshore, a region where the company has already operated for several decades on both the Italian and Croatian sides.

Eni will get a 60% participating interest and the role of operator, in partnership with Rockhopper (40%). The assignment will be formalised upon the signature of the Production Sharing Agreement, expected by April 2015.

The company has been active in Croatia since the 1980s. At present, through its fully owned subsidiary Eni Croatia B.V., it operates jointly with INA's two exploration and production licenses located in the Adriatic offshore, where it holds a 50% participating interest.

Eni is a leading international producer in the country, with daily equity production (2014) of around 1.1 million m<sup>3</sup> of gas. ■

## Chevron makes deepwater GoM discovery

Chevron Corporation has announced that it has made a significant oil discovery at the Anchor prospect in the deepwater US Gulf of Mexico. Anchor is Chevron's second discovery in the deepwater Gulf in less than a year.

"The Anchor discovery, along with the previously announced Guadalupe discovery, are significant finds for us in the deepwater Gulf of Mexico. We had one of our best years with the drill bit in 2014, reporting more than 30 discoveries worldwide and adding an estimated 1 billion bbls of new resources to our holdings," said Jay Johnson, Senior Vice President, Upstream.

The Green Canyon Block 807 Well No. 2 encountered oil pay in multiple Lower Tertiary Wilcox Sands. The well is located approximately 225 km off the coast of Louisiana in 5183 ft of water and was drilled to a depth of 33 749 ft. Appraisal drilling will begin in 2015. ■

## In brief

### Egypt

Reuters reports that the Egyptian oil ministry has signed six new oil and gas exploration contracts with both Egyptian and foreign companies; the contracts are believed to be worth hundreds of millions of dollars.

The companies involved in the agreements include Shell, ENI, BP and TransGlobe Energy. The contracts will cover the drilling of at least 40 exploratory wells in the country's Western Desert and the Gulf of Suez.

### USA

The US government has revealed that the nation's oil production will rise by approximately 600 000 bpd in 2015 and a further 200 000 bpd in 2016, bringing total output to 9.5 million bpd.

The projected increase is lower than previous estimates as some producers have begun to cut back in the wake of reduced prices. A spokesperson for the Energy Information Administration said, "Many oil companies have cut back on their exploration drilling in response to falling crude prices and will concentrate their drilling activities in established areas that already have productive wells."

### Venezuela

According to reports, Venezuelan President, Nicolas Maduro, has embarked on a diplomatic mission to gather support from other OPEC members for a cut in crude oil production.

Maduro has, at the time of writing, met with representatives of Saudi Arabia, Qatar and Algeria.

Despite the financial difficulties faced by some OPEC member states, Saudi Arabia has repeatedly ruled out any cut in the group's oil production.



# World news January 2015

## Diary dates

08 - 11 March, 2015

### MEOS 2015

Manama, Bahrain  
[www.meos2015.com](http://www.meos2015.com)

11 - 13 March, 2015

### Australasian Oil and Gas

Perth, Australia  
[www.aogexpo.com.au](http://www.aogexpo.com.au)

17 - 19 March, 2015

### SPE/IADC

London, UK  
[www.spe.org/events/dc/2015](http://www.spe.org/events/dc/2015)

23 - 25 March, 2015

### Arctic Technology Conference

Copenhagen, Denmark  
[www.arctictechnologyconference.com](http://www.arctictechnologyconference.com)

25 - 27 March, 2015

### OMC

Ravenna, Italy  
[www.omic.it](http://www.omic.it)

04 - 07 May, 2015

### OTC

Houston, USA  
<http://2015.otcnet.org>

## Web news highlights

- ▶ Pump market to exploit E&P activities in global oil and gas industry
- ▶ Enhanced Bakken Supply Chain Initiative
- ▶ CGG chosen for geophysical survey projects in Papua New Guinea
- ▶ ION announces PuntlandSPAN seismic survey

To read more about these articles and for more event listings go to:

[www.oilfieldtechnology.com](http://www.oilfieldtechnology.com)

## KrisEnergy completes Block A Aceh acquisition

Independent upstream company, KrisEnergy Ltd, has announced the completion of its acquisition of Premier Oil Sumatra (which holds a 41.6% stake in the Block A Aceh PSC) from Premier Oil Overseas B.V.

Approval for the change of control has been received from the government of Indonesia and the provincial government of Aceh.

Block A Aceh is located onshore Sumatra in the semi-autonomous region of Aceh and covers an area of 1803 km<sup>2</sup>. It contains several gas condensate discoveries including the Alur Rambong, Alur Siwah and Julu Rayeu fields, which were approved for development in 2007. These discoveries are expected to go into development with first gas from Alur Rambong anticipated in 2017.

The block also contains the Matang gas discovery, which requires further appraisal prior to being developed via tie-back to the initial facilities, and the high-CO<sub>2</sub> Kuala Langsa gas discovery. ■

## New gas discovery for China's CNOOC

CNOOC Limited has announced that the company has successfully made a new mid-to-large sized natural gas discovery Lingshui 25-1 on the independent deepwater exploration.

The Lingshui 25-1 structure is located in the northeast of Ledong Sag in Qiongdongnan Basin of South China Sea, with an average water depth of around 980 m. The discovery well Lingshui 25-1-1 was drilled and completed at a depth of ~4000 m and encountered the oil and gas pay zone with a total thickness of about 73 m. The well was tested to produce around 35.6 million ft<sup>3</sup> of natural gas and 395 bpd of oil.

Lingshui 25-1 is another mid-to-large sized natural gas discovery following Lingshui 17-2.

The discovery has opened up a new exploration chapter in the deepwater area of the northern South China Sea, and further proven the good exploration prospects in deepwater area of the Qiongdongnan Basin. ■

## Total achieves flare-out on its Ofon field, Nigeria – gas to be monetised via Nigeria LNG

Total has completed the flare-out of the Ofon field on Oil Mining Lease (OML) 102 offshore Nigeria. The associated gas of the Ofon field is now being compressed, evacuated to shore and monetised via Nigeria LNG.

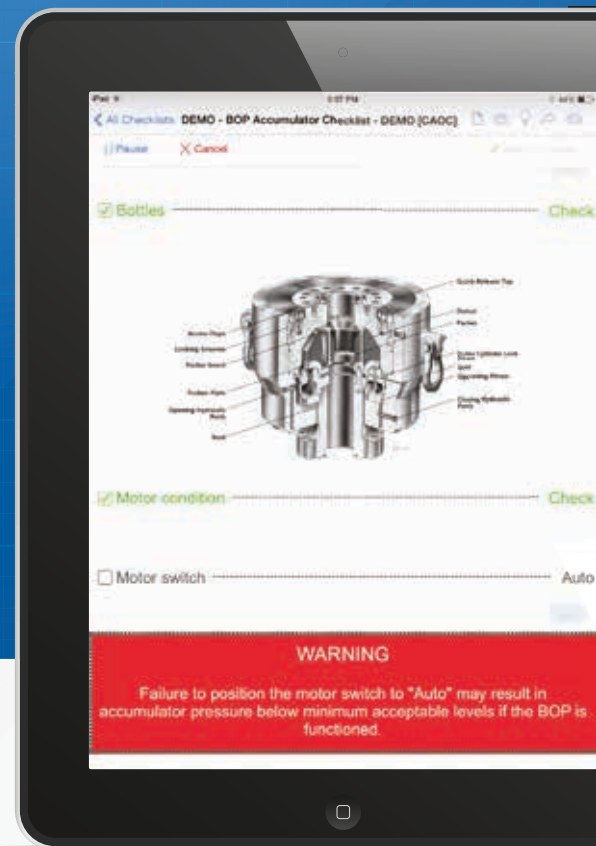
“The flare-out of the Ofon field illustrates our commitment to developing oil and gas resources around our existing hubs in Nigeria. This important milestone of the Phase 2 of the Ofon project was achieved in a context of high levels of local content,” commented Guy Maurice, Senior Vice President Africa at Total Exploration & Production. “The flare-out on Ofon is also significant for Total’s environmental targets, representing a 10% reduction in the Group’s E&P flaring. This achievement is a clear demonstration of Total’s commitment to the Global Gas Flaring Reduction Partnership promoted by the World Bank.” The Ofon field is located 65 km from Nigerian shores in water depths of 40 m. The field began production in 1997 and is currently producing approximately 25 000 boe/d.

This flare-out milestone will allow for the gradual increase of production towards the 90 000 boe/d production target through monetisation of around 100 million ft<sup>3</sup>/d of gas, followed later in 2015 by the drilling of additional wells. The execution of the project also involved significant local content, including the first living quarters platform to be fabricated in Nigeria.

Total E&P Nigeria operates OML 102 with a 40% interest, alongside the Nigerian National Petroleum Corporation (60%). ■



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# World news

## January 2015

### Shell subsidiary agrees to £55 million settlement with Nigeria's Bodo community

Shell's Nigerian subsidiary, the Shell Petroleum Development Company of Nigeria Limited (SPDC), has announced a £55 million settlement agreement with the Bodo community in respect of two operational spills in 2008.

The £55 million settlement provides for an individual payment to each claimant who accepts the settlement agreement in compensation for losses arising from the spills, amounting to up to £35 million in total. The remaining £20 million payment will be made for the benefit of the Bodo community generally.

"From the outset, we've accepted responsibility for the two deeply regrettable operational spills in Bodo. We've always wanted to compensate the community fairly and we are pleased to have reached agreement," said Mutiu Sunmonu, Managing Director of SPDC.

"We are fully committed to the clean-up process being overseen by the former Netherlands' Ambassador to Nigeria. Despite delays caused by divisions within the community, we are pleased that clean-up work will soon begin now that a plan has been agreed with the community.

"However, unless real action is taken to end the scourge of oil theft and illegal refining, which remains the main cause of environmental pollution and is the real tragedy of the Niger Delta, areas that are cleaned up will simply become re-impacted through these illegal activities."

In late 2008, two oil spills took place on the Bomu-Bonny Pipeline in Bodo. Both spills were caused by operational failure of the pipelines. ■

### EFC Group completes contract with shipyard

EFC Group, a designer and manufacturer of instrumentation, monitoring, control and handling systems for the global oil and gas industry, has completed a £1.3 million contract to design and build a BOP and diverter control system for China-based Dalian Shipbuilding Industry Offshore Co. (DSIC Offshore).

The system is installed onboard DSIC's new build jack up drilling rig, JU2000E-13. DSIC is supplying the rig to drilling contractor Apexindo, where it will be known as *Tasha*.

CEO, Bob Will said: "This is a major contract for EFC, continuing our growth plan to become world class leader in control systems for both rig upgrades and new builds alike. It is also a significant project that's been supported by our manufacturing base in Forres." ■

### Petrobras oil and gas reserve growth slows

According to Reuters, oil and natural gas reserves at Brazil's state-run oil company Petroleo Brasileiro SA rose at the slowest pace in six years in 2014, ending the year little changed as new discoveries barely kept up with production.

As of 31<sup>st</sup> December 2014, the Brazilian giant held proven reserves of 13.13 billion bbls of oil and gas. This marks an increase of just 0.1% over figures for 2013 and the slowest growth rate for reserves since a 4.39% fall in 2008.

Former CEO, Jose Sergio Gabrielli, said in 2011 that the company would have approximately 30 billion bbls of reserves in place by 2013, more than double the figure that has emerged recently.

Despite the sluggish reserve growth, Petrobras is set to spend US\$44.2 billion per year as part of a US\$221 billion 2013 - 2017 investment scheme. This heavy expenditure and slow growth have combined to make Petrobras the world's most indebted oil major. ■

### N-Sea extends charter with Siem Offshore

Following three years of operations, N-Sea – an inspection, maintenance and repair (IMR) specialist – has extended its charter agreement with Siem Offshore, concerning its offshore subsea construction vessel, *Siem N-Sea*, previously *Siem Stork*.

The agreement has a duration of up to 6 years, having begun on January 1, 2015.

The *Siem N-Sea* is a dive, multi-support and construction vessel, designed to meet the needs of the offshore subsea industry. It is one amongst N-Sea's fleet of six dive support and specialist intervention vessels, designed to deliver a range of subsea services for offshore assets, platforms, FPSOs and renewable operations, with minimal impact made upon production.

Commenting on the agreement extension, N-Sea CEO, Gerard Keser said: "N-Sea is extremely pleased to have extended its original agreement with Siem Offshore. [...] We look forward to the continuation of this [...] relationship." ■

### Oceaneering announces vessel charter agreement

Oceaneering International, Inc. has revealed that it has entered into a two-year, multi-service vessel charter agreement with Shell Offshore Inc. for use of the *Ocean Alliance* in the US Gulf of Mexico (GoM) commencing January, 2015.

The *Ocean Alliance* is a state-of-the-art, US-flagged vessel built in 2010. It has an overall length of approximately 309 ft, a Class 2 dynamic positioning system, accommodations for 69 personnel, a helideck, a 150 t active heave compensated crane and a working moonpool. The vessel is outfitted with two work class ROVs and is equipped with a satellite communications system capable of transmitting streaming video for real time work observation by shore personnel.

M. Kevin McEvoy, President and CEO, stated, "We are extremely pleased that Shell has committed to this term agreement with us to support their deepwater GoM operations. Shell is one of our largest customers." ■

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**Philip Morel, T.A. Cook Consultants, explores the problems facing oil and gas companies as they look to recruit and retain employees in China.**

**H**ome to more than 24 billion bbls of proven oil reserves, China's oil and gas industry has demonstrated remarkable growth over the past 20 years. Its total oil and liquids production has risen about 54% in that time according to the Energy Information Administration (EIA) and is forecast to increase to approximately 4.6 million bpd by the end of 2014. But as the world's largest consumer of energy, domestic production has not kept up with burgeoning demand, which is driven mainly by power generation, economic and trade growth and refining.

It may seem strange then that a country home to such natural abundance is suffering from a workforce skills shortage. After all, it is also home to the highest population in the world, so the availability of talent should not be something operators or manufacturers have to worry about. However, as many operators are painfully aware, there is a gaping hole between what companies want and what the market can provide, particularly when it comes to middle management.

### **A greying workforce**

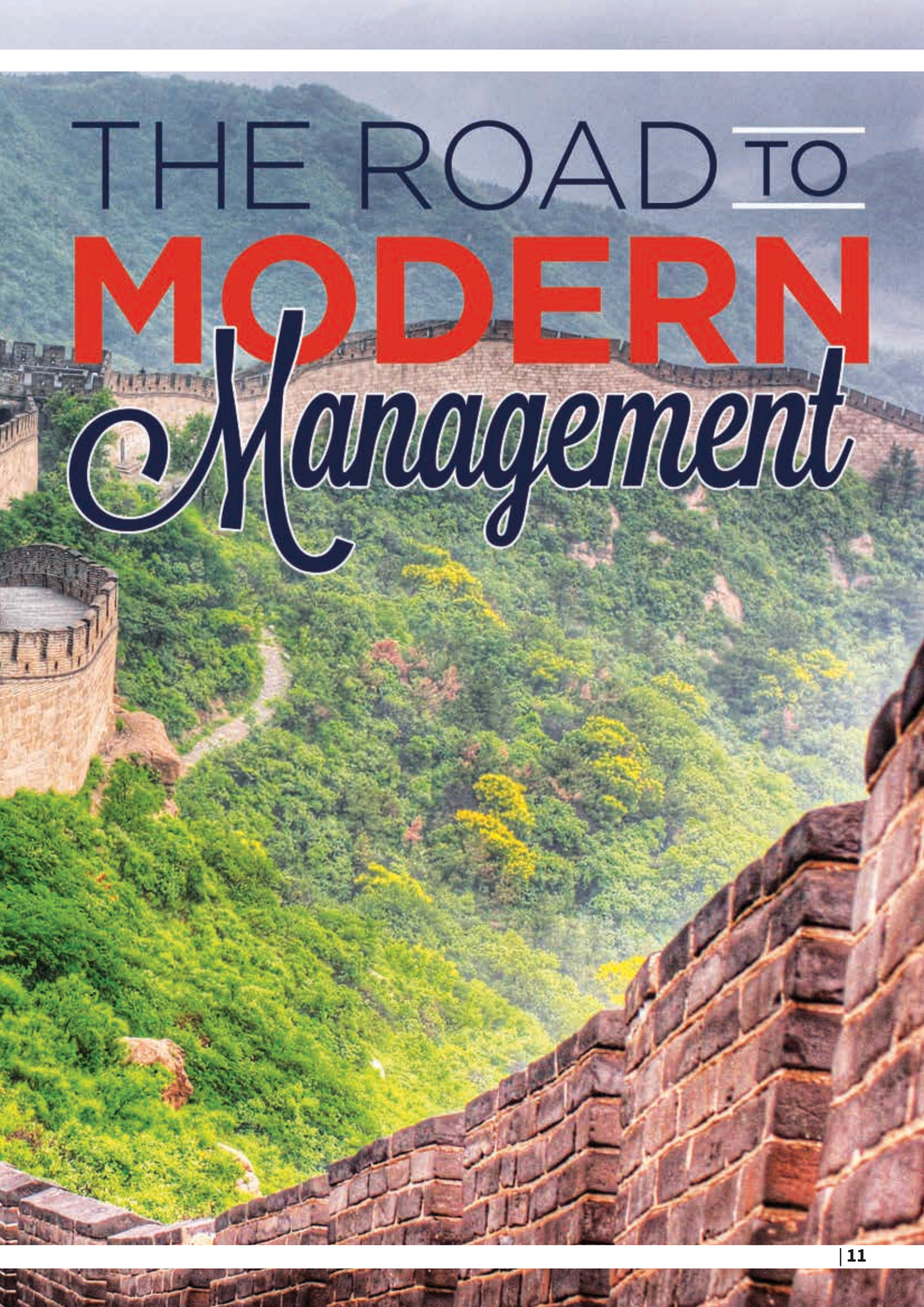
The causes of the current staffing problems for companies operating in China can be broadly divided into the following categories:

demography, social policy and culture. While neither of these alone is responsible for the problem, together they likely form the basis of productivity losses and slower or delayed growth.

Considering demographic issues first, many of the issues affecting China also affect economies in the rest of the world. The United States in particular is also struggling with an ageing population who are starting to enter retirement and take their skills with them. The US Bureau of Labor Statistics points out in its Employment Outlook that by 2020, the baby boomers, who in 2000 were the major contributors to the workforce, will all be over 55 years of age.

Similarly, in China it is estimated that the actual number of people over the age of 60 will have grown from 175 million in 2010 to 250 million by 2020. This is due in part to the one-child policy, which was applied in 1979 and also to campaigns which encouraged women to have children later and with longer intervals between births. Fertility rates have dropped dramatically over the past thirty years, meaning that the percentage of the Chinese population of working age would inevitably be affected.

Additionally, the manufacturing boom had previously been supported by a huge influx of workers from the countryside into the



THE ROAD TO  
**MODERN**  
*Management*

major cities. Factory conditions were often bad and the pay meagre, but still represented an opportunity for advancement that field workers had limited access to. The problem is that the vast majority of people who made that move were not highly educated and very few companies made the effort of training their staff so that they would be able to take on more taxing positions in the future. It adds to that the slowing rate of immigration into the cities, a large number of factories, processing plants and upstream operations have been left without enough workers.

## The factory taboo

As economic growth has increased and many more young people attend university, the attitude of Chinese graduates towards working in factories or processing plants has also changed. As more students study courses involving business or economics, many consider themselves above working in factories. Some attribute this to an age-old Confucian tradition where educated people do not undertake manual labour and some to a simple desire to earn more and move up the ladder faster. Regardless of the motive, even when employers improve working conditions and pay sometimes double what an office job would, many graduates will simply not consider it.

This has revealed a huge mismatch between the jobs that are available and the skills that graduates have. A company needing skilled machine operators or steelworkers will be left either paying through the nose or searching for months on end.

When companies do find someone with the right qualifications, they often lament that the right skills are still not there, indeed that the quality of education has actually fallen. Communication and social skills feature often in these complaints, as does English proficiency, which is of increasing importance to oil, gas and processing companies who trade regularly with America and other parts of Asia.

## Nepotism and management

Another aspect to the lack of appropriately skilled workers has to do with attitudes towards management and politics. The pervading culture of nepotism, which places a large number of often unqualified people in top jobs due to their connections, means that large managerial problems have begun to surface. Such managers tend to have a team of deputies to do their jobs for them, but the managers themselves will never be fired: at worst, they will be moved to another department or company.

Younger, able workers also tend to suffer from the lasting culture of top-down management, where juniors will simply do what their boss says without questioning it even when the basis or logic of decisions are doubtful or abusive. These practices can tend towards a culture of amateurish management, which is often unproductive, but cannot easily be changed.

## Changing tides

With the increase in foreign trade and economic development however, some companies are starting to realise that training both managers and the team working directly for them is of vital importance. Teaching managers essentially how to manage is no easy feat, especially when culture plays a part, but there are some steps that can be taken to make the transition easier.

First, managers need to assess exactly which skills they have and which skills they need. This requires a detailed examination and understanding of the requirements for each particular process. If an experienced manager is retiring, his exact abilities and the tasks he completed need to be established and understood in order to recruit the most accurate fit. It could be that a junior member of staff who

has worked with him is capable of taking over many of his tasks, but needs a bit more time and support to grow into the role. If that is the case, it may be that timelines need to be temporarily altered to allow for the learning phase. Whether the role is filled internally or externally, the focus must be on building the behaviours that are fundamental to making a process work.

Then, installing performance management systems, which are aligned with behaviours, will provide clarity to workers and managers alike. Agreeing on key performance indicators (KPIs) with individuals and how they will be measured – for example against industry standards – will help workers to understand what is expected of them and provide managers with detailed information as to the reasons for delays or failures.

## Long-term commitment

In order to support development and build long-term loyalty, employees must be supported from an early stage. This means ensuring that the requisite training programmes are not only paid for but have the necessary time allotted to them. Once training has been completed, employees should be able to demonstrate and apply the skills they have learned, and it is up to the managers to test and support this process.

Some corporations – such as Shell and Exxon Mobil – have taken the step of setting up their own, specialised training centres. BP has established an ‘Operations Academy’ (OA) in conjunction with the Massachusetts Institute of Technology (MIT) with the explicit aim of building a culture of continuous improvement. In China, Volkswagen Group has even teamed up with the Beijing Vocational College of Transportation to provide dual vocational training and education for over 1500 apprentices, part of the company’s aim of maintaining quality standards to support growth.

Managers must also be part of the training process, and programmes, which allow mentoring and rotation to other locations will help to build a more rounded, pragmatic approach to management. By committing to the long-term training needs of their employees, companies can build up specialised vocational and management skills which outside institutions are currently failing to provide. The process will also contribute to employee loyalty and a culture of improvement, both of which are worth the investment.

## Appropriate rewards

Finally, ensuring that workers who have progressed are appropriately rewarded is particularly important in an increasingly global market. Some major corporations in China have noticed a decrease in the number of college graduates attending recruitment fairs, mainly because some local workers feel that foreign companies prefer ex-pat management and will not reward them for their achievements. While more and more Chinese workers are making it to management level, this perceived glass ceiling needs to be openly addressed and managers must make it explicitly clear that achievements will be rewarded, both with tangible and material benefits.

If companies are prepared to make long-term, strategic plans for the recruitment, training and retention of both managerial and vocational staff in China, significant operational benefits are there for the taking. There are some large cultural and educational obstacles that need to be overcome, but with the right approach, there is no reason that China’s vast workforce cannot be optimised to fit more closely to the demands of the market. Change will not happen overnight, but having already shown a breathtaking capacity for transformation, China’s millions are not to be underestimated. ■



# OPERATING ▪ IN ▪ INTERESTING TIMES

**Frances McLeod  
and Jimmy Ko,  
Forensic Risk Alliance,  
explore the business issues  
affecting the upstream oil  
and gas industry in China.**

**C**hina's economic transformation over recent years has been unprecedented both in terms of pace and scale, with growth rates averaging about 10% since 1978.<sup>1</sup> With economic growth comes an increase in energy demand, making China the world's largest energy consumer.<sup>2</sup> While the Chinese government has been favouring foreign investment in the upstream oil and gas industry for decades, China is still a difficult business environment to navigate for most foreigners.

Coupled with a lack of comprehensive legal and regulatory framework that governs the industry, these factors drive China's relatively high country bribery and corruption risk profile.

In fact, bribery and corruption in China is nothing new. Since 2002, approximately 28 enforcement actions brought by the US Securities and Exchange Commission and Department of Justice involved business activities in China,<sup>3</sup> and more prominently GlaxoSmithKline was recently fined by Chinese authorities for nearly US\$ 500 million in a bribery case.<sup>4</sup>

There has also been a recent anti-corruption clampdown on government officials across the country at historic scale, with more than 182 000 party officials being investigated and punished in 2013 alone.<sup>5</sup> Perhaps most relevant to this article is the clampdown on former and incumbent senior executives at China National Petroleum Corporation (CNPC), China's largest oil and gas producer and supplier. This includes Jiang Jiemin, head of the powerful state-owned Assets Supervision and Administration Commission (SASAC) and former Chairman of CNPC.<sup>6</sup> While it is worth noting that many of these convictions and clampdowns are politically driven, there are also likely to be wide reaching consequences for private companies related to CNPC.

But with a plethora of thought leadership pieces on identifying and navigating through China's bribery risks, the potential damage of other types of fraud, such as asset misappropriation (e.g. fraudulent disbursement) and financial statement fraud (e.g. revenue overstatement) cannot be understated. The level of fraud inherent in Chinese businesses dwarfs corruption.

To understand the scope of issues affecting the upstream oil and gas industry in China, it is prudent to dissect these issues through the lenses of the fraud triangle. The fraud triangle, developed by criminologist Dr. Donald R. Cressey, sought to explain why people commit fraud. It consists of three elements that are necessary for fraudulent behaviour to occur – incentive/pressure, opportunity, and rationalisation.<sup>7</sup> This is a tried-and-true model in understanding issues related to fraud.

## Pressure to commit fraud

China's economic slowdown over recent months has been clear – industrial output grew at its weakest pace since late 2008, and housing sales contracted a further 8% this year.<sup>8</sup> In an underdeveloped capital market where both investment and credit issuance slowed, businesses and investors are finding it increasingly difficult to access capital in China.

With the recent crackdown on bribery and corruption violations, company executives are now told to meet their growth target, but without the use of 'old tricks'. Coupled with decreased access to capital, this creates additional pressure to commit other types of fraud, from asset misappropriations to financial statement fraud. Based on conversations with local contacts, increased suicide rates has been noticed amongst company executives due to increased pressure to perform, and worse so if one is under investigation on suspicion of taking bribes.<sup>9</sup>

## Opportunities to commit fraud

### Joint ventures

While most people understand the concept of direct fraud, which include schemes like paying ghost employees, falsifying financial statements etc., indirect forms of fraud are just as common, and not easy to detect. In China, foreign enterprises seeking to invest in oil and gas exploration and production are commonly partnered with one of the Chinese state-owned enterprises (SOEs) through a co-operative joint venture (CJV).<sup>10</sup> Even for oil and gas services companies where it is now possible to set up wholly foreign-owned subsidiaries, legacy CJVs are commonplace.

Many seemingly private companies in China are actually SOEs owned or operated by government officials, and are a form of

nepotism that has been around as long as the country itself. Often, companies are set up to take advantage of the JVs. As an example, the JV would order printing supplies or large machinery from a single-sourced supplier, but what this 'supplier' does is simply mark up the goods and services directly bought from another supplier.

Under the Foreign Corrupt Practices Act (FCPA) and other anti-bribery and corruption (ABC) statutes, SOEs are considered instrumentalities of the government and subsequently, employees of SOEs are considered foreign officials for the purpose of the statute. Payments to SOE employees are considered a direct violation of the FCPA.

JVs in China generally have oversight issues and expose partners to various types of fraud risks. In many instances, partners do not readily have access to the relevant books and records of the JVs, and it is not uncommon that only financial statement level data is sent by the JVs to the partners. Indeed, instances have been observed where the partners must visit the JVs personally to obtain detailed financial information, which is indicative of a lack of transparency into Chinese JVs or where effective management reporting has broken down. In addition, Chinese accounting software and language issues add a layer of opacity, which can also be abused.

As a result, the importance for a company to conduct proper due diligence before it engages a business partner in a JV cannot be understated. Such due diligence should also include an ABC books and records review, Forensic Risk Alliance has noted numerous instances where JV partners would simply present falsified financial statements and documents as supporting documentation. Further, having a strong say in and implementing robust internal controls should provide additional protection against oversight issues.

### Lack of law enforcement

Operating in a country with a lack of enforcement of Intellectual Property (IP) rights implies that companies can be faced with situations with wildly variable profit margins. Where profit margins of a new product based on years of research and development are expected to be very high when it is first introduced, such profit margins can quickly erode as competitors learn to illegally reverse-engineer the patented technology. This means that upstream oil and gas companies that have spent millions on the research and development of unique products may not receive the necessary IP protection needed to secure profit.

The general lack of transparency to the books and records of Chinese companies compounds the above-mentioned problem, and creates further opportunities for fraud to occur. A company can only recording the net revenue in its books without reflecting the discount given – such instances are commonplace and are difficult to detect. There have been instances where volume discounts to customers/distributors in China are used to mask illegal payments or set up 'slush funds' outside of the accounting system.

### Compliance culture with Chinese characteristics

China presents particular challenges from a compliance perspective due to a number of factors.

First, the hierarchical nature of Chinese society means that people tend to respect differences in status much more than others. In short, decisions are made by people at the top and are followed by the people below, hence people are much less likely to speak up or ask questions about a particular transaction that they find unusual or troubling. Multiple companies in China also indicated a general lack of specific ongoing ABC training for in country personnel.

Second, most people who do business in China have come across the term 'guanxi', or relationship building, which is built on the exchange of favours. It is important to pay proper respect to the other parties in China, and not create situations where others might



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'lose face'. Here, favours can come in many forms, from direct cash payments through agents and third parties to government officials, lavish dinners, single-sourced suppliers or even employment of relatives of government officials as a quid pro quo for winning tenders or getting certain licenses/permits approved.

It is paramount for companies operating in China to conduct proper third party vendor due diligence. This is particularly true for companies operating in the upstream oil and gas industry, where interactions with government agencies, agents, distributors and other goods and services providers are everyday occurrence. Indeed, the vast majority of FCPA cases in recent years involved third parties.

Bearing these factors in mind, ABC training to employees in China should extend beyond the definition of bribery, corruption and an introduction to the company's policies and procedures. ABC training in China should include a discussion of the historical corruption issues prevalent in the region, including those that prompted US SEC and DOJ investigations and the discussion of real life examples. Training should also include modules to allow finance staff to properly identify potentially fraudulent transactions, and include training on FCPA red flags (e.g. handwritten documentation or round dollar expenses), fake fapiao (government-issued receipts<sup>11</sup>) and identification of parties that interact with government officials. This will increase the overall awareness of finance function employees and empower them to act as more effective gatekeepers.

## Rationalisation to commit fraud

### Limited opportunities to advance

The underlying unemployment issues in China are problematic – those who are better educated are less likely to be employed than those who are less educated.<sup>12</sup> As China's economic growth is mainly driven by the manufacturing sector, it does not offer large number of white-collar jobs suitable for university graduates. Coupled with an increased income gap between the rich and the poor,<sup>13</sup> it is not surprising to see that an increasing number of Chinese do not believe that hard work equals success, and more people turn to a cheating/corrupt mind-set to advance in society. It has been observed that employee fraud within a company continues to be a serious problem for companies operating in China. In fact, the use of fake fapiao and supporting documentation in China is the most common mechanism to extract cash from firms, either as fraud to enrich employees or as a means to fund bribes.<sup>14</sup> This is further evident through the proliferation of the fake fapiao industry, with estimates putting the amount as high as 1 trillion yuan (US\$ 157 billion) a year.<sup>15</sup>

## Conducting investigations

### Seek counsel/professional help

In the event that a company needs to conduct an internal investigation or due diligence on third parties, it is advisable to seek the help of counsel and professionals who have substantial experience working in China, not only because they will be conversant in the issues discussed above and be able to identify, quantify and potentially resolve them, but also because there are additional China-specific challenges.

Data privacy laws in China are complex and vague. There is currently no systematic approach to data protection regulation in China, and there are currently no national data protection laws, nor industry specific data privacy and protection laws relating to the oil and gas industry. Nevertheless there are considerable risks and challenges to collecting and reviewing Chinese data (i.e. data that is in China) in part because the state secrecy law is frequently invoked. To further complicate the timing and scope of an investigation, China has also issued strict guidelines to restrict access to company information,<sup>16</sup>

possibly in light of the exposure of the business interests and assets of Chinese leaders, including President Xi Jinping and past Premier Wen Jiabao, through publicly available information.

The recent arrest and conviction of Peter Humphrey (a British investigator who worked for GlaxoSmithKline in China) and his wife<sup>17</sup> underscores the lack of systematic approach to data protection regulation in China, but it also highlights the importance of navigating through this space with tact and consideration. It is important to understand the source of information obtained from third parties, to retain companies with established reputations for lawful research and investigation, and to require them to only use methods that do not violate Chinese laws.

In addition, the definition of state secrets under Chinese law is also broad, and includes a catch-all category covering matters "as determined by state departments for the maintenance of secrets"<sup>18</sup>. The state secrets law also restricts the export of electronic data (including emails) outside of China, and Hong Kong is treated as a foreign country for purposes of the law.<sup>19</sup>

With these reasons in mind, one can appreciate that conducting an investigation or due diligence in China has a very different set of dynamics and demands than that of Western countries in general. As such, it is important to engage counsel with experiences navigating through the demands and nuances of the Chinese legal environment when conducting internal investigations or due diligence in China.


## Conclusion

Despite its open door policy, China is still a tricky place to navigate for upstream oil and gas businesses. With the recent economic slowdown, underlying unemployment and income inequality issues such as a backdrop, risk areas such as joint ventures, lack of enforcement of IP rights and the general compliance culture in China all contribute to increased opportunities to commit fraud. But with all the risks associated comes potential rewards. With an understanding of the Chinese political and business environment, a more hands-on management and careful navigation through the potential risk areas and the implementation of robust controls, one can turn obstacles into opportunities. ■

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# MANY HANDS MAKE LIGHT WORK



Karyna Rodriguez and Dan Negri, Spectrum, Neil Dyer, ARKeX, and Håkon T. Pedersen, EMGS, examine petroleum system insights provided by multi-client data integration case studies.

**S**eismic data is an extremely powerful tool for investigating and understanding the geological, tectonic and stratigraphic components of basin evolution and defining potential petroleum systems. However, with increasing costs, competition and the move into higher risk areas, it is more critical to identify and mitigate the subsurface risks in order to obtain commercially viable discoveries. The desire to extract more from seismic data requires innovative working practices that can be achieved with an integrated evaluation process. This article describes a selection of case studies to illustrate how the integration of seismic data with other tools and methodologies greatly enhances the interpretation of all available data, thereby increasing interpretation confidence and reducing subsurface risk.

## **Gravity gradiometry approach for enhanced velocity model, improving depth-migrated seismic image, Gabon**

The South Gabon Basin is a prospective basin in approximately 100 - 3300 m water depth. Along the South Gabon margin the ubiquitous late Aptian evaporites (Ezanga salt) extend from the continental shelf in the east to the oceanic crust in the west creating



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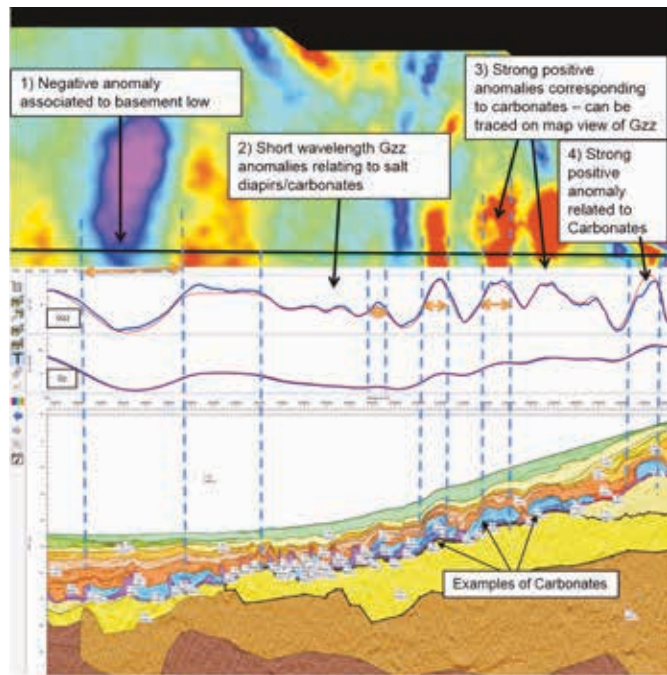
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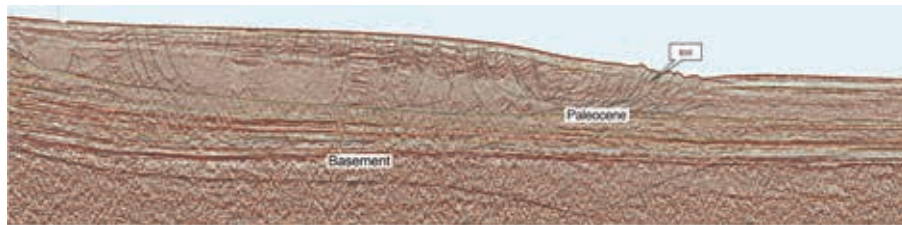
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Late Cretaceous/Palaeogene deepwater turbidite plays encouraged by successful wells in French Guiana.

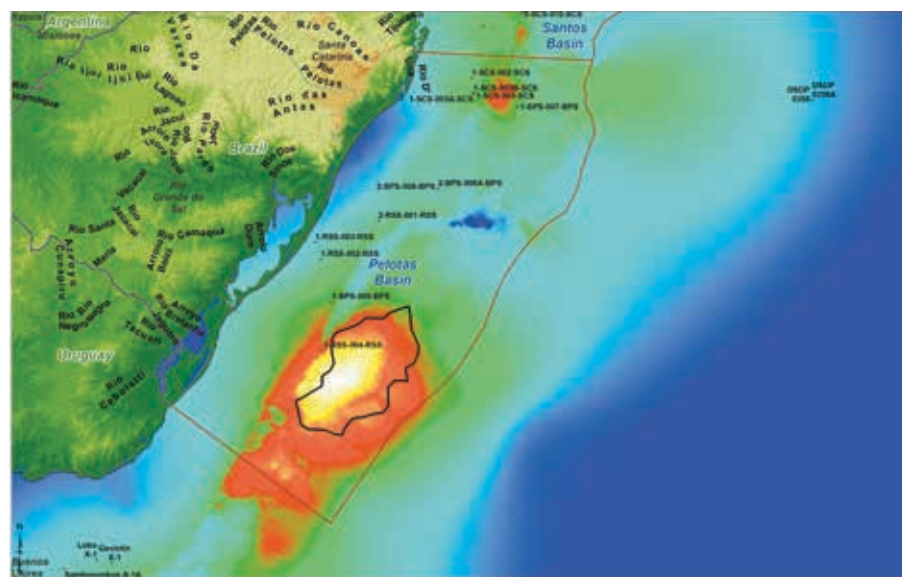
Late Cretaceous/Early Palaeocene Limoeiro Formation and Middle Miocene Orange Formation comprise turbidite sandstones with average porosity of 13%. Aptian shales are a potential



**Figure 2.** A Gzz base map and corresponding 2D density model of dip-oriented 2D seismic section with Gz and Gzz observed and calculated profiles.



**Figure 3.** Dip-oriented PreSTM seismic section showing Pelotas's basin geometry and bottom simulating reflector.



**Figure 4.** An isochron of Tertiary deposition and limit of the Rio Grande Cone BSR in the Pelotas Basin.

hydrocarbon source rock with up to 10% TOC and excellent potential for oil generation. The shales at the base of the Limoeiro Formation are a second hydrocarbon source rock with TOC's up to 3.5% and good to excellent oil/gas generation potential. The Limoeiro shales provide a regional seal. FdA has considerable exploration potential; ANP 11<sup>th</sup> Round presentation quoted in place volumes of 14 billion bbls of oil and 40 trillion ft<sup>3</sup> of gas.

In 2012 Spectrum acquired 21 369 km of 2D seismic, gravity and magnetics data providing a regional grid and a suite of final products (PreSTM, PreSDM, Gathers, Angle stacks, Velocities) to evaluate the FdA exploration potential (Figure 5).

In 2013 EMGS acquired approximately 4500 km<sup>2</sup> of 3D Controlled Source Electro Magnetic (CSEM) data in a 2.5 x 2.5 km receiver grid in water depths ranging from 200 m to 3000 m. The receiver grid filled in the Spectrum 5 x 5 km 2D seismic grid with a minimum of 3 receiver lines deployed at all times providing true broadside data at 2.5, 5 and 7.5 km offset.

The preliminary interpretation identified several large Late Cretaceous/Palaeogene anomalies in the basin. An example of one seismic lead comprising a thick package of Cretaceous turbidites with a corresponding CSEM anomaly is illustrated in Figure 6.

EM anomalies are observed in the deepwater sediments with varying strength. By choosing an average resistivity window that encompasses the expected burial depths of the Lower Tertiary and Upper Cretaceous channel systems, some EM anomalies resemble channel geometries. In strike direction, some of the channels observed on Spectrum seismic are associated with high resistivity while most channels are not.

The combination of modern seismic, gravity, magnetics and CSEM data provides a powerful exploration tool for identifying and de-risking exploration leads in frontier basins. With potentially large multilevel leads and large areas of open acreage Foz do Amazonas provides an exciting frontier exploration opportunity that will feature in future Brazil licence rounds. The results of the FdA integrated interpretation will be published in a report and available for purchase in 2014.

### Integration of sea surface slicks and seismic interpretation to define play concepts in the western Mediterranean

The western Mediterranean Basin is largely unexplored with no wells drilled in the deeper water parts of the basin. Exploration has been limited to the shallow water Mesozoic carbonate trend where two oilfields; Casablanca (Lower Miocene source) and Amposta (Jurassic source) have been developed.

Between 2011 and 2013 Spectrum reprocessed 25 000 km of seismic data; the largest 2D seismic dataset in the region covering the entire basin (Figure 7).

Analysis of sea surface slicks visible in satellite images was integrated with seismic interpretation to identify the areas where a functioning hydrocarbon source is likely to be active thereby significantly de-risking this play component in the basin. The integration

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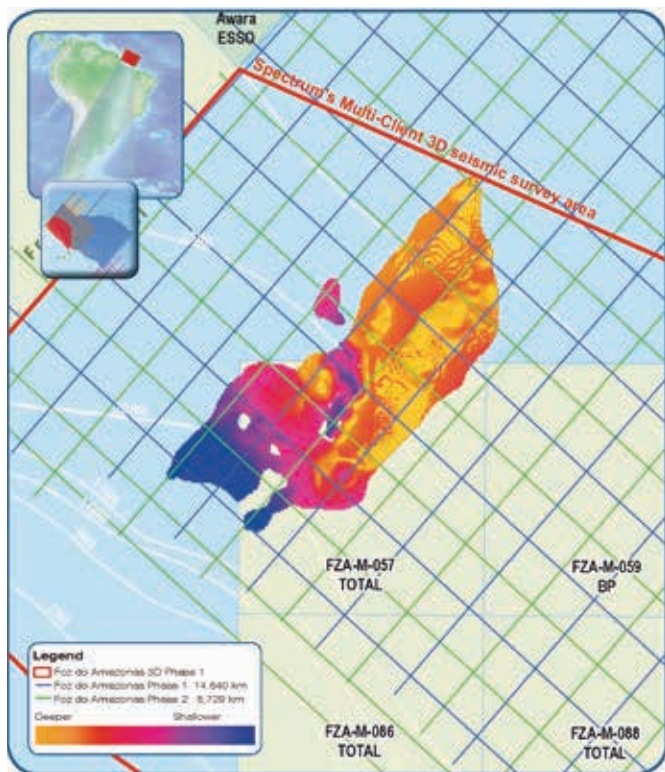
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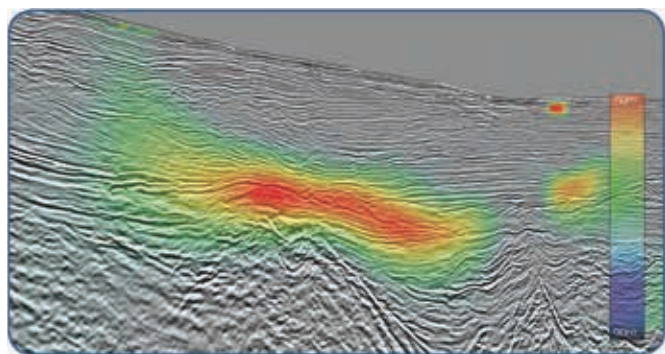


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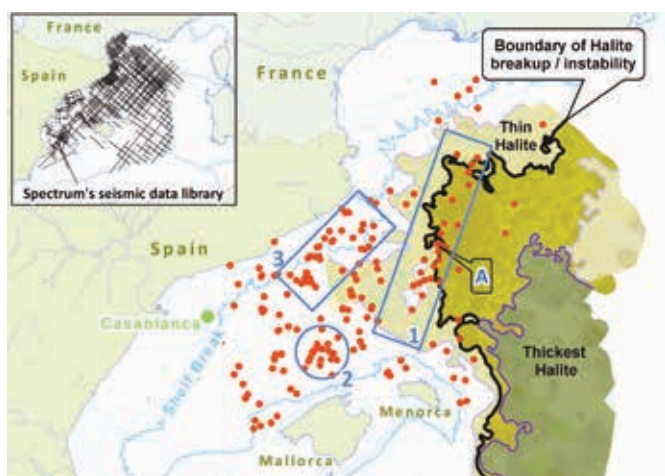




**Figure 5.** Location of the integration of the CSEM anomalies with pre and post stack seismic attributes, and pre-stack depth migrated sections.



**Figure 6.** Positive resistivity anomalies shown within Late Cretaceous-Palaeocene clastic deposits, confirming hydrocarbon potential suggested from seismic mapping of several channelised systems.



**Figure 7.** Distribution of sea surface slicks in the Western Mediterranean (red), identified trends (blue), and the Messinian halite canopy. Inset figure is Spectrum's seismic coverage over the Western Mediterranean Basin.

is important because differentiation between natural hydrocarbon seeps and anthropogenically sourced slicks is difficult to assess using satellite imagery alone. Correlation with seismic interpretations is key to understanding the results of any slicks study.

Several trends were identified in the sea surface slicks study and correlated with interpreted seismic profiles. The clearest trend (Figure 7, Trend 1) correlated closely with up-dip thinning and breakup of the regionally extensive Messinian halite. Several slicks (Figures 7, 8) were identified in association with a fault that breached the halite canopy and reached the sea floor.

A second trend (Figure 7, Trend 2) not associated with the halite canopy, is associated with the margins of an eroded anticline onto which potential Mesozoic source rocks onlap. With the Miocene source interval of the Casablanca trend immature here it is proposed that this Jurassic source, analogous of the Amposta field may be viable in the deep water sector of the basin. Other slicks (Figure 7, Trend 3) also support evidence of this play type, suggesting that this Jurassic source is present and mature across the basin.

The integrated seismic-seep study provides good evidence of a working petroleum system below the Messinian halite seal in the deepwater basin, and in the deeper Mesozoic interval. The results have de-risked the hydrocarbon charge and suggest that presalt or Mesozoic prospects have the potential to be charged with oil.

## Geological and geophysical data integration to determine the hydrocarbon potential offshore Croatia

Offshore Croatia lies in the NE of the Adriatic Sea (Figure 9). Plio-Pleistocene fields produce commercial biogenic gas from clastic reservoirs in both Italian and Croatian waters while in the Italian southern Adriatic Sea oil is produced from pre-Miocene carbonates. Whilst the Italian Adriatic has been successful for several reasons the Croatian offshore is relatively unexplored.

Spectrum completed an integrated evaluation of the 2013 2D and legacy seismic, well data, ship borne gravity and magnetic data and seep data. The results were integrated with basin modelling and AVO analysis to identify the hydrocarbon potential of the offshore Croatian basins. Several new plays and leads were identified with considerable yet-to-find potential offshore Croatia.

The integration of seismic with gravity and magnetics data resulted in the structural interpretation of the basin. Correlation of observed Permo-Triassic faults with the 'gravity edges' obtained from 2013 gravity data (Figure 9) defined the major structural domains and potential source basins. The interpretation suggests that gravity trends are mainly affected by the Permo-Triassic syn-rift structures. Seismic and gravity data highlighted N-S and E-W fault trends and a major regional fault system oriented NW-SE. Gravity edges were used to extend some of the structural trends identified on seismic and to define trends not imaged on the seismic data. Integration of these datasets provided a clearer view of the structural grain and defined the major source rock basins and structural highs.

To understand the distribution and influence of the halite sequence an integrated workflow was adopted and resultant products conflated:

- ▶ Identification of salt diapirs on the 2013 seismic.
- ▶ Derivation of instantaneous frequency attribute and correlation with the known diapirs to characterise the response. Generation of maximum salt and minimum salt interpretations across the basin.



- ▶ Magnetic and gravity maps correlated with characterised salt.
- ▶ Seismic interpretation and characterisation of salt features.

Gravity modelling undertaken by BridgePorth investigated the sensitivity of the ship borne gravity data to the distribution of salt in the section. A 2D geological model built to complement the gravity model confirmed the salt bodies generally corresponded to low gravity anomalies.

The integration of these techniques has been important in defining the amount and distribution of salt in the basin. Whilst most halite diapirs are readily identified on seismic, the distribution of halite in the section is still the subject of discussion. Understanding the role of salt in the development of the basin is crucial as halokinesis influenced the development of structures and traps in the basin. It also influenced the deposition and distribution of the Late Triassic source rock and the Cretaceous, Jurassic and Eocene platform carbonates in the basin.

The seep study integrated a radar study conducted by Airbus DS along with an optical study undertaken by Spectrum. The presence of seepage slicks implies that an active source is present and that there are migration routes within the basin. In the Adriatic, 16 seep-seismic correlation points were identified and the results show a strong correlation between slicks nominated as medium confidence or higher and structural features interpreted from seismic. Slicks were located in association with faults, thrusts, salt diapirs and anticlines.

In addition to halite the late Triassic section contains a potential hydrocarbon source rock comprising organic rich mudstones and associated inter-tidal algal mat sabkha deposits. This was input into a basin modelling study based on the integrate interpretation and completed by Stratochem Ltd. The results produced an estimate of the timing of source rock maturation, assessed the hydrocarbon charge history, predicted migration pathways, drainage areas, and potential hydrocarbon accumulations for the 46 000 km<sup>2</sup> of the Adriatic Sea. The model was conditioned by data from 34 wells and four pseudo wells. The results identified key areas of mature Late Triassic oil generation and are summarised in Figure 9.

High amplitude gas leads were analysed for AVO attributes and their response compared with producing biogenic gas discoveries. The gas anomalies distribution plotted as mainly class IV with some class III at shallower depths and class II indicative of oil component in the deeper sections.

The integrated evaluation using several technologies significantly aided the prospectivity evaluation of offshore Croatia. The various methodologies and datasets provided a better understanding of the structural trends, the impact of halokinesis and ultimately defined the hydrocarbon potential of the basin.

In a high cost, high risk operating environment the five case studies described above illustrate the benefits to be gained from integrating

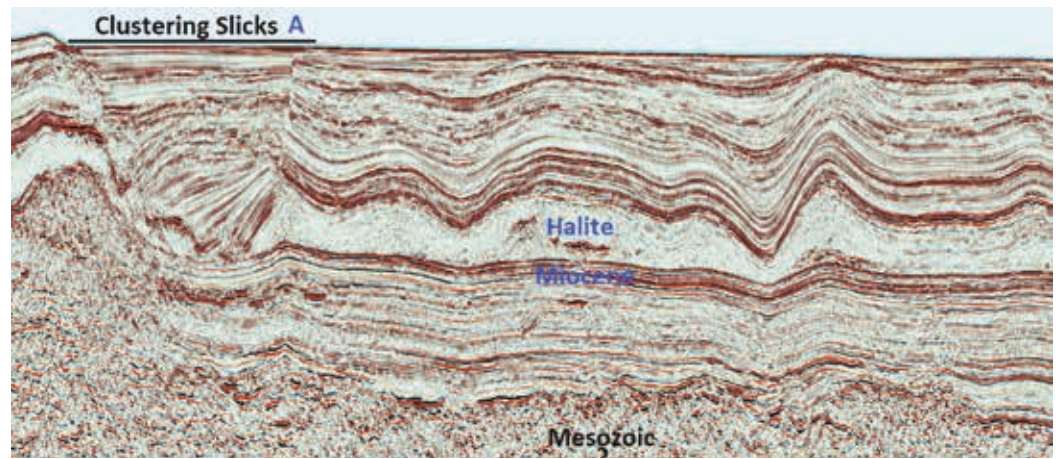


Figure 8. NW-SE dip line SPBAL-16 ('A' correlates with 'A' in Figure 7).

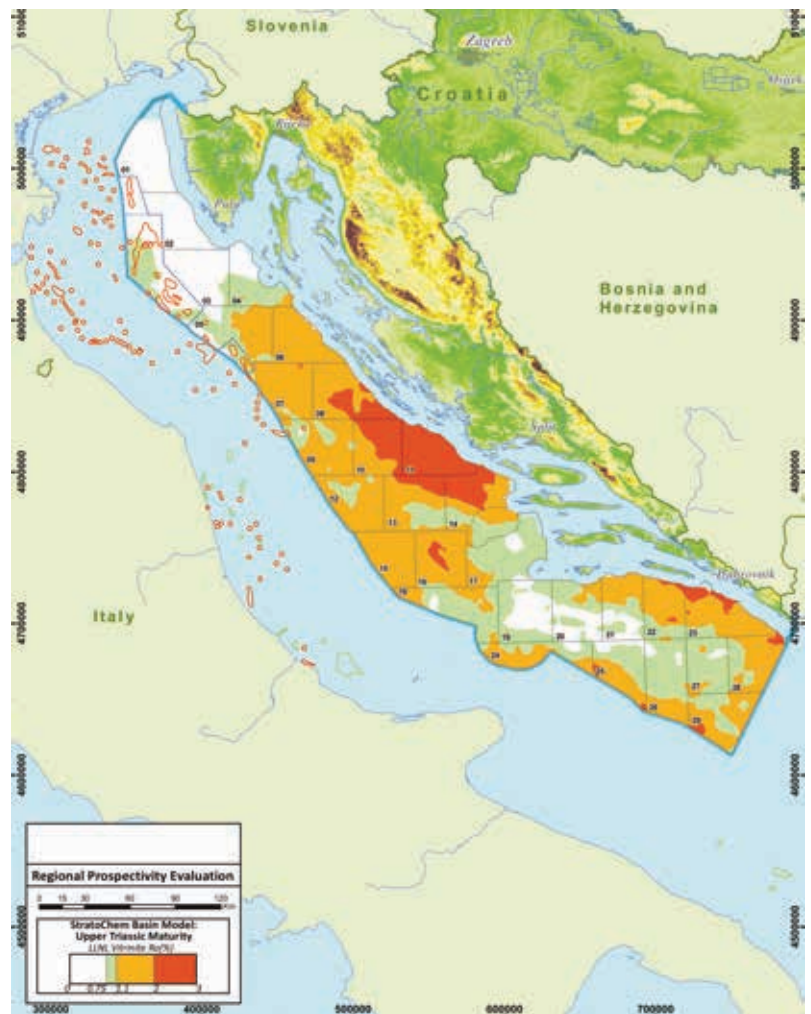


Figure 9. Late Triassic maturity map. Green corresponds to peak oil generation, orange wet gas and red dry gas generation.

subsurface data and methodologies to improve interpretation confidence and ultimately reduce uncertainty in new ventures exploration. ■

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Peter Baillie, CGG, reveals how broadband data has begun to unlock the secrets to finding hydrocarbons in the Banda Arc.

**T**he Banda Arc (Figure 1) is one of the most geologically complex and controversial areas on Earth, comparable in some respects to the Caribbean. The horseshoe-shaped 'arc' (in the geometric rather than the geological sense), lying north of Australia in East Indonesia and Timor Leste, represents the collision zone between the continental crust of the Australian tectonic plate and the Indonesian archipelago. It comprises the deep and ultra-deep Banda Sea enclosed by a volcanic inner arc (the Inner Banda Arc), outer arc islands (the Outer Banda Arc) and a series of fore-deeps (the Seram, Tanimbar and Timor troughs) marginal to the edge of the Australian continental crust and more-or-less parallel with the outer arc.<sup>1</sup>

The area is of great interest to petroleum explorers because of abundant onshore and offshore oil and gas seeps and similarities with geologically contiguous Mesozoic and Cenozoic successions in Australia where numerous petroleum systems exist and have been exploited (the Mesozoic basins are collectively termed the 'North West Shelf'). Exploration of the offshore Banda Arc has previously been limited because of water depths, remoteness and seismic

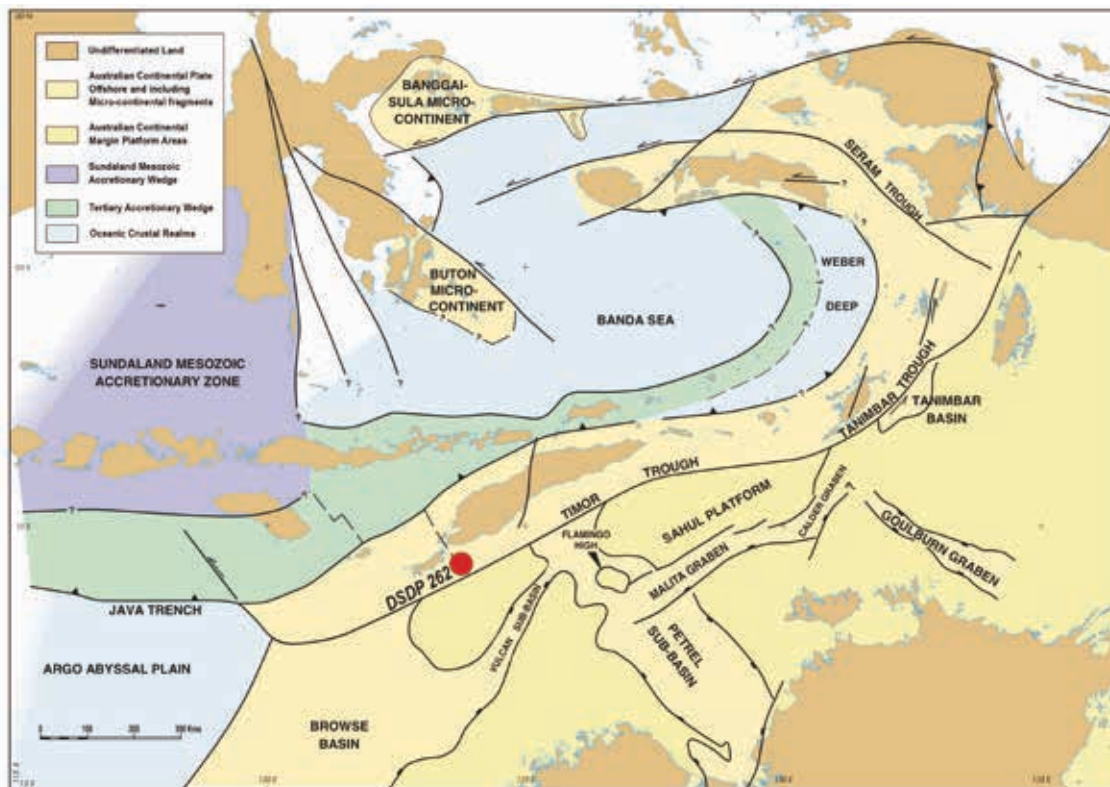
An aerial photograph of a tropical island, likely in the Banda Arc region, featuring lush green vegetation and a coastline with turquoise waters. Overlaid on the image is a large, semi-transparent teal circular graphic with concentric rings and radial lines, resembling a stylized globe or a technical diagram. The text is centered over this graphic.

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# BANDA

# ARC



**Figure 1.** Geological setting of the Banda Arc showing Inner Banda Arc lying between Banda Sea and Webber Deep and Outer Banda Arc comprising curved edge of Australian continental plate: DSDP 262 indicated (modified after Baillie et al., 2004).



**Figure 2.** Google Earth image showing BandaSeis seismic survey components (Phase 1, West Timor, yellow; Phase 2, east of Timor, green; Phase 3, white; Phase 4, Timor Leste, red).

imaging problems associated with a zone of deformation occurring between the fore-deeps and the Banda Sea.

### BandaSeis project and observations

In co-operation with the Indonesian Directorate General of Oil and Gas (Migas) and the Timor Leste National Petroleum Authority (ANP), CGG has acquired four phases of multi-client seismic data around the Banda Arc; collectively, these surveys are known as the BandaSeis Project (Figure 2). The data has been acquired with CGG BroadSeis™ broadband technologies and processed in depth: the regional Phase III data is currently being processed and will not be discussed in this article.

Outboard of the fore-deep system (that is, away from the Banda Sea in the geometric sense and south of the island of Timor), relatively undeformed sedimentary successions contiguous with Australia's Bonaparte Basin flex down towards the trough and continue towards the Banda Sea (Figure 3). The succession extends in age from Late Paleozoic to Recent and shows the typical horst and graben extensional features as seen elsewhere on the North West Shelf. Preliminary analysis of the data indicates the presence of regional Late Triassic inversion, and late Jurassic fault-controlled

deposition, together with Cretaceous and Cenozoic extension. Large fault scarps attest to very recent movements, probably related to wrenching, in some areas.

Inboard of the fore-deep system (that is, on the Banda Sea side) a spectacular thin-skinned fold-and-thrust belt has formed on a series of basal detachment faults or décollements (Figure 4). The bathymetric depression (that is, the Timor Trough) marks the zone where the distal end of the fold-and-thrust belt has either accreted onto, or incorporated down-flexing continental material.

BroadSeis technologies have enabled the thin-skinned fold-and-thrust belt to be imaged for the first time. The fold-and-thrust belt absorbs the entire higher-frequency signal and the section below can only be seen at very low frequencies, less than 5 Hz. A prominent bottom-simulating reflector (BSR) confined to the fold-and-thrust belt is commonly observed.

The data shows in great detail the complex interplay between sedimentation and tectonics from Jurassic to Recent times. Prominent delta foresets high in the section indicate that shallow water conditions existed until the last 2 - 3 million years, consistent with observations at DSDP 262 where deepwater Quaternary and upper Pliocene planktonic ooze overlies upper Pliocene shallow marine dolomitic mud and Pliocene very shallow marine dolomitic shell calcarenite.<sup>2</sup> The common presence of about 100 m of undeformed pelagic or hemipelagic sediments draped over the deformed zone indicates that, in large part, the fold-and-thrust belt is no longer forming (Figures 3 and 6), an observation supported by lack of modern earthquakes in the region.

### Prospectivity

Ample testament to the presence of a working petroleum system in the Banda Arc is provided by onshore and offshore oil and gas seeps. Onshore oil and gas seeps occur commonly throughout the islands of the Outer Banda Arc: oil from both Seram and Timor

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has been typed to a Late Triassic or Jurassic carbonate source.<sup>3,4</sup> Numerous oil and gas seeps occur in the offshore realm:<sup>5</sup> a short distance east of Timor the 12 km diameter Raksasa mud volcano (Figure 5; Raksasa = giant in Bahasa Indonesia) has yielded oil typed to a probable Jurassic source.<sup>6</sup>

South of the trough, exploration drilling has shown that much of the Mesozoic (and in particular, the Jurassic) is immature for hydrocarbon generation. The formation of the fold-and-thrust over relatively undeformed Mesozoic section has pushed Jurassic (and older) source rocks into the oil window and explains the presence of oil seeps such as Raksasa.

Potential traps north of the Timor Trough include horsts and fault-related features in the Mesozoic section beneath the fold-and-thrust belt (Figure 3) and structural highs associated with probable strike-slip faults observed to be present within the deformed zone (Figure 6).

## Discussion

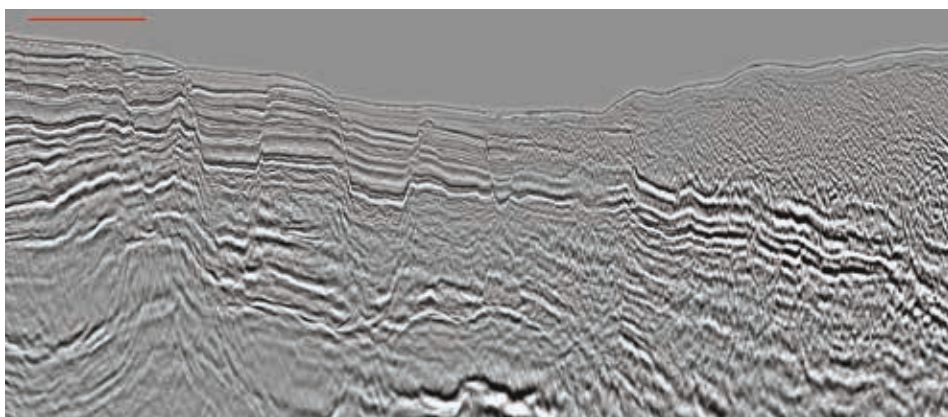
It has been suggested that the Banda Arc largely results from Neogene subduction that commenced around 15 Ma when active Java subduction tore eastwards into a Jurassic oceanic embayment, which largely occupied the area of the present Banda Sea.<sup>7</sup> There is general

consensus that Banda Sea subduction, a continuation of that currently occurring in the Java Trench, ceased with the arrival of buoyant Australian continental crust at the subduction trench. With the arrival of the Australian continental crust (the trench and volcanic arc collided with the southern embayment margin in the northern Timor region) around 3.5 Ma, subduction quickly slowed and ceased. Finally, at around 2 Ma, the Weber Deep was created, marking the complete consumption of the embayment by rollback.<sup>7</sup>

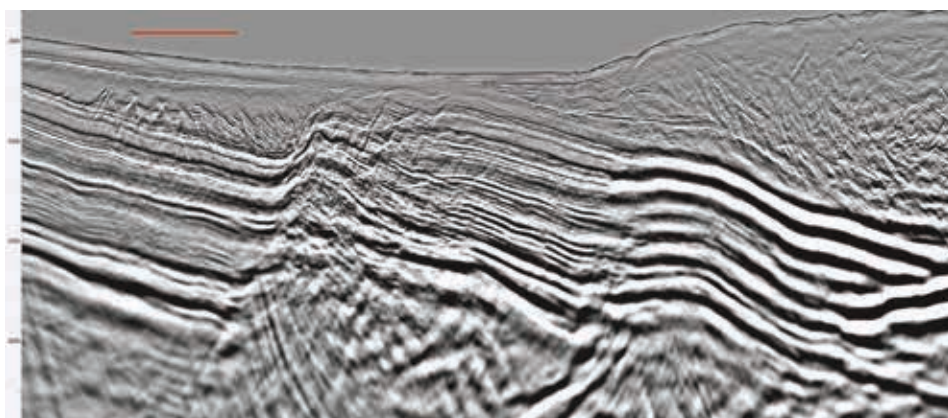
Although it seems likely that development of the fold-and-thrust belt over down-flexed Australian continental material and subsequent Timor Trough formation took place shortly after subduction ceased, it seems highly unlikely that these events are unrelated to what was happening in the Banda Sea. The cessation of subduction cannot be a simple process.

Unfortunately there is no seismic data linking the new data and the island of Timor. Emergence of the island took place in a series of phases commencing in the Late Miocene around 5.7 million years ago.<sup>8,9</sup> Foraminifera indicate that a deep foreland basin, the precursor to the present Timor Sea, had developed by 5.7 Ma with uplifted areas to the north in an emerging island.<sup>8</sup>

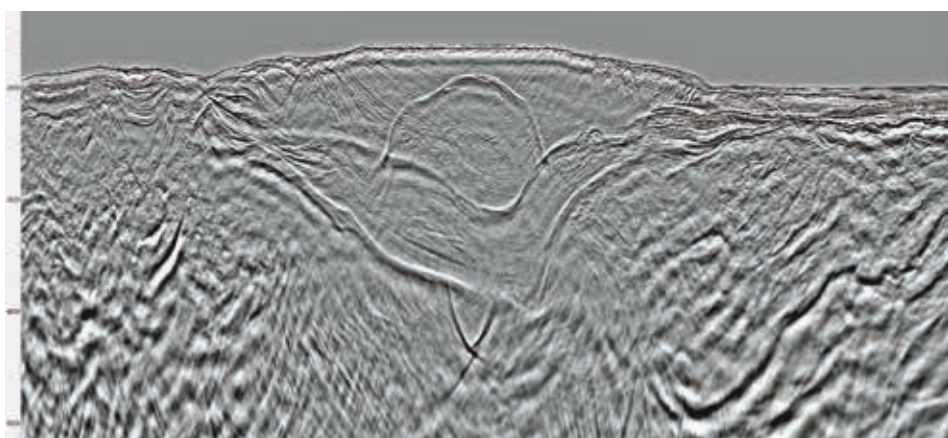
Palynology of exhumed Pliocene marine turbidites and marl beds on Timor provide important insights to the ongoing tectonic processes.<sup>10</sup> Between ~4.5 and ~3 Ma, palynomorphs were sourced primarily from Australia and New Guinea, with increasing swamp and mangrove elements sourced from an emerging proto-Timor. Following ~3.1 Ma, pollen and charcoal evidence track the rapid uplift of Timor to a high island, with the progressive appearance of montane and dry, lee-side floristic elements.<sup>10</sup> Early- to mid-Pliocene uplift rates of 0.5 - 0.6 mm/yr increased to 2 - 5 mm/yr in the latest Pliocene, consistent with the observations made offshore relating to the deepening of the Timor Trough and formation of the fold-and-thrust belt at the same time. It is



**Figure 3.** Seismic depth section south of Timor; red bar 8 km, vertical scale in km.



**Figure 4.** Seismic depth section showing Timor Trough detail; red bar 2 km, vertical scale in km. Note frequency contact change beneath fold-and-thrust belt.



**Figure 5.** Seismic depth section showing Raksasa mud volcano; volcano is 12 km in diameter, vertical scale in km. Prominent downward-curving feature cutting mud volcano is interpreted as interface between gas hydrates and free gas, normally parallel with sea bottom (reflecting the geothermal gradient) but deflected here by upwelling fluids which carry oil being generated at depth.

also noted that Timor's emergence from the marine environment is closely correlated with the timing of closure of the Indonesian seaway to deep-dwelling foraminifera.<sup>8,10</sup> In view of the overall synchronicity of offshore and onshore events, it seems likely that the processes resulting in the formation of the offshore fold-and-thrust belt were also responsible for the uplift of Timor.

The exact processes resulting in the formation of the fold-and-thrust belt are not yet fully understood but are clearly related to the arrival of a thick body of continental material at the site of subduction.

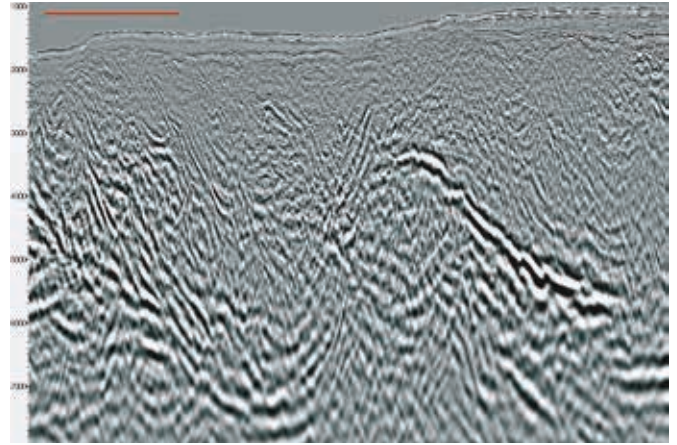
CGG has commenced comprehensive geological studies in the region in an attempt to understand the geological evolution of this remarkable area. ■

### Acknowledgements

The author wishes to acknowledge the support for the project given by the governments of Indonesia and Timor Leste and to the numerous colleagues at CGG who have contributed and continue to contribute to the project – in particular he acknowledges Christian Milne.

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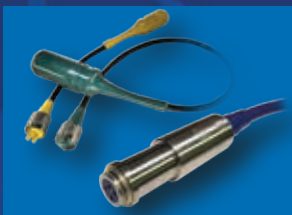


**Figure 6.** Probable strike-slip fault within fold-and-thrust belt; red bar 6 km, vertical scale in km.

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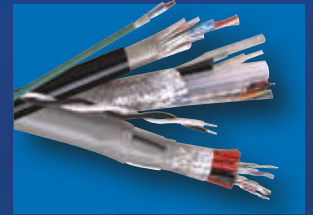
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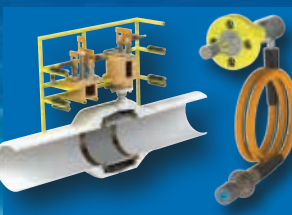
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A photograph of an offshore oil rig structure, featuring a large red cylindrical component and yellow safety railings, set against a backdrop of a blue, choppy ocean. The image is framed by a blue and white geometric border.

LIFE IN THE

# ***FAST LANE***



**Figure 1.** AHV Joshua Chouest hauling in chain to connect the messenger chain and topsides chain.



## JONATHON D. MILLER, INTERMOOR INC., USA, REVIEWS A FAST-TRACK MOORING INSTALLATION IN WATER DEPTHS OF 4400 FT.

**A**s the use of polyester ropes continues to become more commonplace in the offshore mooring industry, their strength requirements (and subsequently, their size) increase. Because of the limited number of manufacturers offering offshore polyester mooring ropes, and because of current safe design practices, the components in a mooring system (i.e. ropes, chains and connecting hardware) must often be ordered at least a year in advance of the installation.

Meanwhile, to save costs, prudent operators secure a long-term contract with an anchor-handling vessel to support drilling operations. This vessel sometimes becomes the mooring installation vessel for new developments. Utilising a vessel already on contract can significantly reduce the costs when favourable terms for the operator are negotiated. When the vessel is secured under long-term contract for drilling support, it is typically not fully known if it is adequately compatible with the proposed mooring components to be installed.

Unique challenges emerge from these two common practices, which become apparent when developing the installation procedures. Very few organisations are willing or able to prepare and successfully execute the installation of a mooring system without first knowing the size and length of the mooring components. Typically, the components drive the selection of the appropriate vessel for installation. A front-end engineering design (FEED) study is often performed before the procedure writing begins. Successfully managing the space between the already selected components and the pre-selected vessel demands creativity and resourcefulness on the part of the engineers developing the procedures and of the operators implementing them in the field.

### Delta House FPS

With hull fabrication in South Korea and topsides construction in South Texas, fabricating and installing the Delta House floating production system (FPS) unit was a global endeavour. Mooring components came from multiple continents. The Delta House FPS is intended to handle up to 20 risers through which it will receive produced oil and gas and then export them for further refinement. Following a practice that allows it to distinguish itself from its competition, LLOG Production Company has become well-known for

its ability to fast-track developments delivering two recent deepwater developments in less than two years from steel order to the issuance of the certificate of acceptance from the United States Coast Guard.

Recently, the second of these (Delta House FPS) was installed in 4400 ft of water at Mississippi Canyon Block 254. Designed to last 25 years, the size of the mooring components bumped the upper limits of what the selected installation vessel (*Joshua Chouest* anchor handling vessel) could deliver.

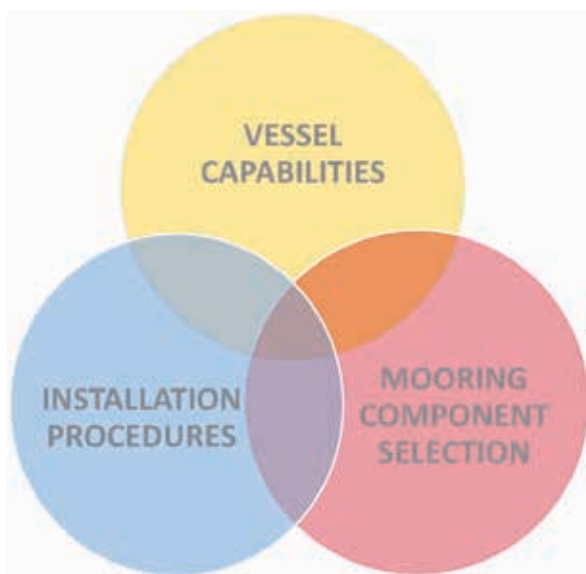
### Mooring components

Moored by 12 legs with three at each corner, the Delta House FPS is designed to survive a 100 year storm. The suction piles are 16 ft in diameter by 85 ft in length, and (via mooring rope and chain) hold the FPS fast above the designed location. Each suction pile weighs approximately 150 t. Type III Subsea Mooring Connectors (SMC-III) facilitate the connection of the mooring line and components to the anchor at the sea floor. This system is a taut-leg design utilising chain and polyester tension members.

Chain diameters of 137 mm mean that each link approaches 1 yard (0.9 m) in length and weighs over 460 lbs (approximately 209 kg). This massive size caused unique challenges for the personnel connecting the mooring components. Normal handling practices could no longer be utilised. Mambo shackles, which normally could be assembled by one or two people, now required three or four and the use of specialised lifting equipment. To illustrate the size of these components, the pin alone for the shackles used to assemble the Delta House mooring leg weighs over 650 lbs, had a diameter of 9 in. and a length of a little more than a yard (3.05 ft). Virtually all positioning of the equipment and components required tugger winches and speciality handling tools. Typically, most of these operations are accomplished by manual labour of the deck hands. With the enormity of the components and their corresponding mass, it was impossible to complete the assembly of the system using traditional methods.

In addition, the polyester segment size and length was too great to be deployed from the primary winches of the anchor handling vessel (AHV). Alternative methods of deployment were formulated to make it possible to use the previously selected vessel to accomplish the work.

A careful eye and steady hand from the winch operator became the motto during deployment to prevent rupturing the cover and exposing the core ropes and fibres to the environment.



**Figure 2.** The intersection of vessel capabilities, mooring component size, and workable installation procedures is where the work gets done.



**Figure 3.** Employees review rigging and procedures one last time before over-boarding a suction pile for installation in the Delta House mooring system.



**Figure 4.** Chain handling on AHV Joshua Chouest. Note the modified chain chutes (in burgundy instead of dark orange), which routed the chain from the lockers to the whelps and back deck.

## Installation vessel

*Joshua Chouest* is a 288 ft long AHV with a 66 ft beam and a 29.5 ft height. It has a deadweight tonnage of 4744 t. Equipped with two Caterpillar diesel engines, each with a brake horse power of 15 200 bhp, the *Joshua* has a bollard pull of 200 t. There are also five winch drums, of which two are anchor handling drums and two are storage reels. The main tow drum has the largest capacity.

In order to develop procedures that work for an offshore installation, it is important to survey the proposed vessel(s) to ensure that the equipment is capable of handling the mooring components effectively. For Delta House, this survey took place over a year in advance of the installation.

The chain segments were test fitted in the proposed whelps to ensure that lowering of the connection between the messenger chain and the topsides chain could be performed safely. While writing the procedures to install the very large chain proposed for Delta House, it became clear that the chutes delivered from the shipyard when the *Joshua* was built were too small to accommodate the 18 in. girth of each link. The capacities of the chain lockers were also examined to ensure that they could accommodate the proposed lengths of chain.

Equipped with a remotely operated vehicle (ROV), the *Joshua* was technically suited for the subsea connection of the SMC-III which links the anchor chain to the ground chain and ultimately the FPS. The ROV was used to 'arm' the connector for locking prior to joining.

## Custom installation aides

In order to make the assembly of the chain and shackle components more efficient and to reduce the risk to personnel on the back deck, an A-frame was manufactured with chain hoists on the top rail. These were used to help position the pin and shackle such that the chain or polyester could be connected. Additional measures were taken during the mobilisation of the equipment at the dock to further expedite the offshore assembly.

The weight of the chain attached to the male end of the SMC-III connector was so great that the chain had to be lowered from a synthetic lowering line to share the load and not rupture the jacket of the polyester mooring rope.

To ensure adequate back-tension was kept on the lowering line during recovery after deployment of the preset lines on the seabed, a section of stud-link chain was added between the ROV hook and the lowering line. This made it necessary to develop some methodology to secure the smaller diameter chain in the shark jaws. An insert was designed and fabricated to help reduce the spacing between the shark jaws and the smaller stud-link work chain.

Synthetic rope slings made from HMPE fibre ropes were also used for the deployment and recovery slings on the top chain to lay it on the sea floor. In addition, similar slings were used for the connection between the anchor chain and the ROV hook on the end of the lowering line.

Conceptual designs for additional assembly aides to support greater efficiency on future systems have also been created by InterMoor engineers.



**Figure 5.** Connecting large polyester rope segment to mooring chain segments.

These aides will help make future work with large diameter chain on similarly classed vessels more efficient.

### Installation analysis

As permanent mooring systems get larger and larger, utilising traditional anchor-handling vessels for the installation is proving more and more challenging. Flexibility, adaptability and innovation are critical to extending the capabilities of the existing fleet of anchor-handling vessels to keep pace with larger mooring components, to maximise returns, and deliver projects on time and within budget constraints.

The Delta House mooring system was deployed and installed safely and on time, without incident. The system was successfully connected under high loads (because of very short messenger chain lengths). Close attention to tolerances and connection interfaces were paramount to the accomplishment of this project. Technical innovations extended the capabilities of the designated anchor handling vessel, minimised twist in the mooring and ensured cost effectiveness that would not have been possible with another vessel.

The FPS is designed for a peak capacity of 100 000 bpd of oil and 240 000 ft<sup>3</sup>/d of gas. First production from the facility is expected in the first half of 2015.

### Conclusion

Though challenges arose during the installation process, the Delta House FPS was moored in 4400 ft of water at MC-254. Hookup operations were performed safely and efficiently in spite of the utilisation of the *Joshua* at maximum handling capacity. Novel installation aides were developed to help facilitate this work in the future. Creativity, perseverance and persistence were all employed in minding the gap between the already selected vessel and the pre-selected mooring components saving the client significant costs by using an already chartered asset for the installation and hookup work. ■



**Figure 6.** Custom made installation aide to extend the capability of the Shark Jaws.



**Figure 7.** Delta House FPS as seen at night from back deck of an AHV.

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**Josiah McVicar, Delmar Systems, Inc.** discusses an effective technique for training and hazard assessments related to mooring system deployment over and around subsea oil and gas infrastructure.



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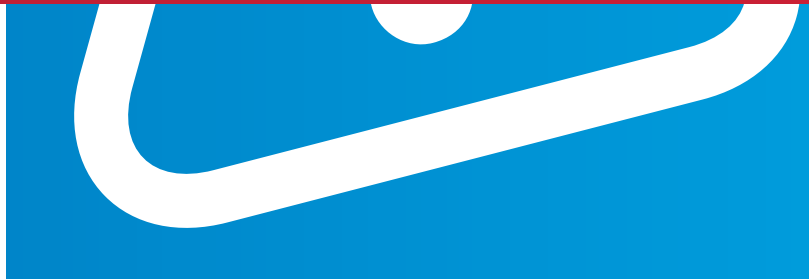
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# CONSEQUENCES



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**W**ith the ever-increasing density of subsea infrastructure offshore, mooring operations are becoming more involved. Deploying mooring equipment over and around assets often requires site-specific mooring plans and procedures designed to mitigate risk to the existing facilities. The consequences associated with wrapping a heavy chain around subsea infrastructure during deployment or recovery of a mooring system are significant from both a monetary and environmental risk perspective. Competent personnel executing well-developed procedures are essential to a successful operation.

The aviation industry uses flight simulators, the automotive industry uses vehicle simulators, law enforcement and the military use firearm simulators, and chemical/electrical industries use process simulators as tools for training people and assessing procedures. While not a substitute, these simulators supplement on-the-job training and provide a way to prepare workers and test systems for both normal day-to-day operations, as well as rarely occurring events.

Del-3DM™ provides a similar tool for the offshore mooring industry. Its purpose is threefold: training, hazard assessment and competency evaluation. Through the use of a series of custom-built software modules coupled with an industry proven calculation engine, OrcaFlex™, Delmar engineers create a job specific virtual rig move scene. This scene incorporates location specific subsea infrastructure layouts combined with numerical models of the rig, platform, tugs and anchor handling vessels. Wind tunnel test data is incorporated to model wind and current loading on the vessels. Wave forces and vessel response are represented by a hydrodynamic database created via a radiation/diffraction analysis of the vessel specific geometry and loading conditions.

With the international nature of the offshore industry, personnel mobilise for mooring jobs from various countries around the world. Housed within a large Pelican case, the Del-3DM hardware package is within the allowable limits for checked baggage on commercial flights. This portability allows the team to assemble at any

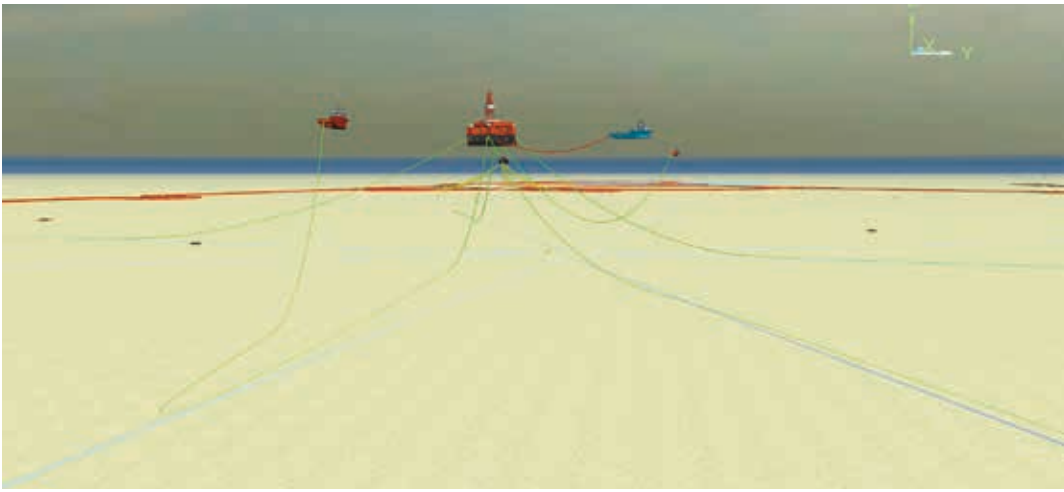


Figure 1. Del-3DM captures mooring line profiles not seen from a surface vessel.

## Training

The system can be used to convey lessons learned from previous experiences. Mooring operations can be difficult to visualise. By walking out on the deck of an anchor handling vessel, drilling rig, or production platform, one can observe the departure of the wire or chain into the water, but understanding the behaviour of the mooring line underwater is more difficult to comprehend. Del-3DM provides a 3D visual depiction of the underwater position of the mooring line throughout the course of deployment.

Circumstances that have resulted in problems, accidents, or near misses in the past can be re-created with the system. Trainees can then take the helm to demonstrate how they will deal with a particular situation. Constructive feedback can be provided during or after the exercise and the replay critiqued by both the instructor and trainee. If need be, the exercise can be repeated to demonstrate the transfer of knowledge or the skill obtained.

## Hazard assessment

Using Del-3DM, the entire rig move can be simulated, in blocks, from start to finish – from the tow in on location, running of the first anchor, winching/kedging of the rig or platform, hooking up to preset moorings, or proof-tensioning of anchors. If simulated prior to the typical pre-job HAZID, additional hazards that are specific to the particular job can be identified that might otherwise be overlooked.

For example, a full HAZID and risk assessment is conducted prior to a semisubmersible rig move mooring recovery operation. During the rig move, a chain comes in contact with a piece of subsea equipment while winching the rig between the safe zones designated for anchor recovery. Upon investigation, it is discovered that the movement of the rig between safe zones was

not identified as a hazard or risk. By simulating the task in Del-3DM, the team would have identified this as a hazard or risk.

Each mooring job is different and has its own intricacies. By identifying these hazards in the pre-job phase, mitigations can be put in place or procedures altered to reduce or eliminate the risk. In the example above, this might translate into assigning extra hands on deck to get a visual on the departure of the line from the rig, hold points with tension verification along the way, and additional survey equipment to monitor the position of mooring catenaries.

## Competency evaluation

A resume or CV should be part of a competency evaluation but it certainly should not be the extent of it. The best way to assess an individual's competency is to observe him/her in action. With a multi-million dollar

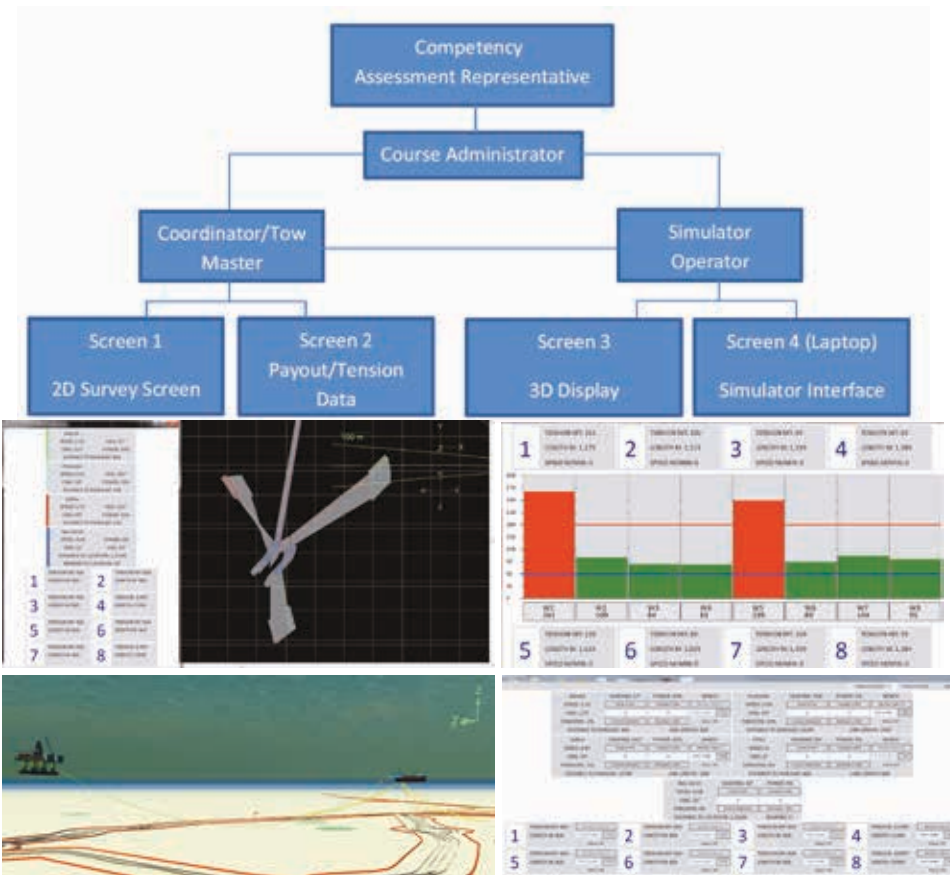


Figure 2. Multiple screens used to display the Del-3DM interface.

convenient location around the world rather than having to travel to a specific venue to complete the simulated mooring exercises prior to job mobilisation. A conference room with standard 110/220 V wall power is all that is needed.

## Target audience

This system provides benefits to towmasters, marine representatives, marine warranty surveyors, rig move co-ordinators, anchor superintendents, mooring engineers, winch operators, barge captains and offshore installation managers, confirming procedures are sound and providing confidence that the job can be completed successfully. The tool can also help during the design and procedure development phase, helping design engineers and operations support staff vet various mooring options in order to arrive at the optimal solution.

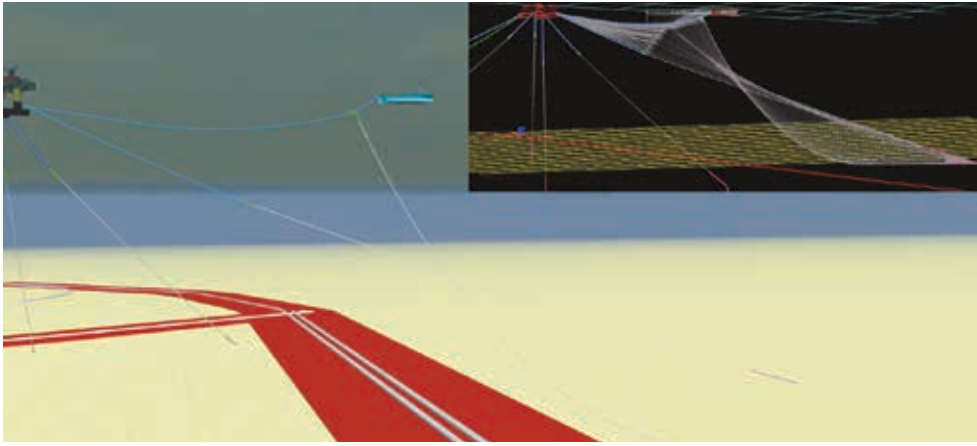
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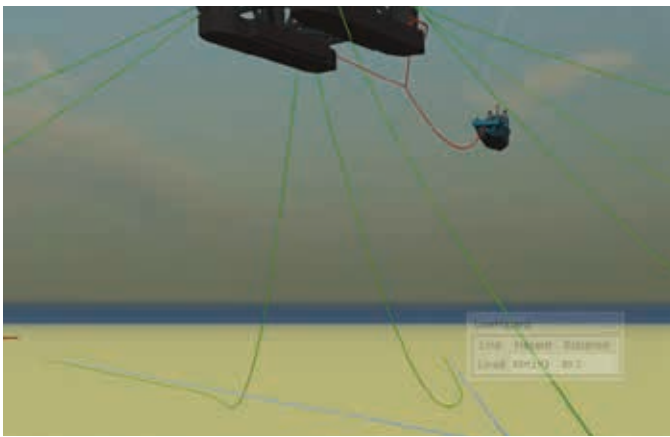
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**Figure 3.** Mooring line load being transferred to rig after anchor handling vessel connects to preset mooring.



**Figure 4.** Doglegs formed in grounded components due to friction. The minimum line clearance to a hazard is shown in transparent overlays.

operation on the line, the offshore mooring arena is not the ideal place to assess the competency of an individual. Ideally, this would be done in a setting where mistakes have little or no consequence.

As part of a comprehensive competency evaluation, simulation allows an individual to demonstrate capability and competence to execute specific tasks related to mooring line deployment and recovery. For example, pulling a 50 000 t displacement vessel to a particular location with the aid of multiple boats, all while weathering a 30 knot wind coming from one direction and a 2 knot current coming from another, can be a difficult task. Once on location, the facility needs to be held steady within the designated safe zone while the mooring lines are deployed over critical subsea oil and gas infrastructure. This turns into a balancing act of extreme proportions that takes the skill and experience of a competent rig mover. Del-3DM provides a medium for rig movers to demonstrate that they are up to the task.

## Overview

Structured as a series of modules, Del-3DM breaks the mooring operation down in order to capture details associated with discrete tasks and provides for natural breaks in the process. Currently, the software consists of five modules:

- ▶ Module 1: arrival on/departure from location.
- ▶ Module 2: running/recovering conventional anchors.
- ▶ Module 3: winching/kedging.
- ▶ Module 4: preset connection/disconnection.
- ▶ Module 5: proof tensioning.

Four screens are used to display the interface. Two screens are dedicated to the trainee; one screen displays the 3D scene, while the remaining screen serves as the interface for the simulator operator.

Inputs are provided by the trainee in the form of verbal commands as would be used over the radio on the platform or drilling rig. Boats are ordered to come up or down on the power, change heading, or payout winch wire. Winch operators on the platform are ordered to payout or haul in on specific winches or chain jacks. The simulator operator interprets these commands and instructs the system to complete these tasks in the order they were received. All vessels are coupled in Del-3DM, so as the boat deploys wire from its winch, the rig or platform will respond to the change in load. Tools are included to monitor clearance distances between mooring lines that are being deployed and the surrounding subsea infrastructure.

The simulated survey screen emulates a typical survey screen used when conducting mooring operations offshore, including vessel position, heading, CMG and speed. The survey screen shows the plan view of the subsea infrastructure relative to current vessel positions.

Similar to a load-monitoring interface on the rig, Del-3DM provides the trainee with a screen that shows the length of mooring component deployed along with the load on the deployment winch. A bar chart graphically displays this information and high and low tension alarms can be set by the trainee.

The 3D scene can either be shown to the trainee or reserved for viewing by the simulator operator and assessor only depending on the intent of the exercise at hand. This screen shows the position of the platform, vessels, mooring lines, anchors, subsea infrastructure and surrounding facilities in space, illustrating their relative proximity throughout the deployment or recovery process.

Actual interaction with the software takes place through the simulator operator console. This provides the medium for translating the trainee's commands into actions within the software. There are faults that the simulator operator can introduce into the system via the console as well that compromise the information that is being displayed to the trainee. This assesses the ability to recognise when information being displayed is incorrect possibly due to a faulty sensor.

## Concluding remarks

Training to manoeuvre large facilities with tugs and anchor boats while deploying and recovering mooring lines has been generally relegated to on-the-job training. While it is recognised that there is no substitute for this type of training, Del-3DM provides a tool to convey concepts and lessons learned between seasoned rig movers and young up-and-comers. This type of training is intended to supplement on-the-job training rather than replace it while providing an avenue to explore a multitude of 'what-if' scenarios without consequences.

With new standards such as SEMS coming into play, companies are giving more thought to documenting employee training and competency. Simulator exercises are an excellent means to provide a record of training and competency assessment in order to comply with these new standards and regulations.

Running through a simulated rig move prior to execution offshore provides confidence that the job is well planned and capable of safely being executed. Using Del-3DM, personnel involved in the operation have already completed the rig move before they ever start, thus providing the individual confidence desired going into the field.

With the stakes involved with offshore operations, it is imperative that highly trained, capable and competent personnel are executing well-developed procedures designed to mitigate the associated risks. ■





# RAMPING UP

## ROV EFFICIENCY

Gregory Eskridge, Teledyne Oil & Gas, USA, reviews the evolution of a wet mate optical connection system design aimed towards enhanced ROV operational efficiency and reduction of risk at installation.

Only two decades ago, the number of subsea deepwater projects and the number of ROVs and associated pilots was a fraction of what exists in the oil and gas industry today. The ROVs and pilots were a select group with vast amounts of experience and were allocated around the globe to work on deepwater projects. The instances of high dexterity wet mate connector mating requirements were relatively low and accomplished by a small group of highly experienced pilots. The production fields were more compact; the instance of sensors, controls and manifolds were less complex. Moreover, the cost of the ROV time was lower and of less impact than today and the concept of

streamlining ROV operation efficiency was not regarded as a high priority given numerous other challenges.

More recently there has been a tremendous increase in the number of deepwater projects coupled with a significant increase in both the size and complexity of ocean floor production fields. These new production fields can cover vast geographies in much deeper water, introducing greater challenges. With this increase, the number of ROVs and ROV pilots has increased in step. Generally, the ROV operations are quite involved and the tasks are varied with inspection, lifting, cutting, actuating levers and moving equipment from location to location. It is not unheard of for a pilot to attempt to connect a wet mate flying lead without ever having been trained on connector handling. The cost of ROV time on location and in operation is a focus today with increased effort to understand factors contributing to ROV operational costs and improvements that can aid in increasing efficiency and reduced associated costs while mitigating performance risk. A mechanically damaged wet mate connector, with a low initial cost of acquisition, can delay or shut down operations at costs that easily dwarf the initial outlay for the components themselves.

### Increasing complexity

The increase in the complexity of the subsea deepwater production factories has introduced a large increase in the quantity of sensors, manifolds, controls equipment and in turn, many wet mate electrical, optical and hybrid wet mate connection assemblies that are required. Many of the modular components, sub-systems and systems required to construct these subsea production factories have been redesigned and reworked to increase operational efficiencies in assembling, operating and maintaining the fields for the required 30 year performance design life.

This article is intended to focus on one of the remaining modular elements affected by operator (pilot) variability; the subsea wet mate optical and hybrid flying lead connections. Process controls and proficiency variability in achieving successful wet mate interconnect exist between ROV pilots due to a number of factors including: the increase of flying leads required, the increased complexities and breadths of the production fields, variability in the ROVs and manipulator arms and in the training and simulation required for these fine dexterity operations.

A movement exists today to study and remove the remaining factors of this variability. New mechanical designs, tools and aids are under development to increase efficiency, lower risk and mitigate proficiency gaps between ROV pilots through designing in process controls that allow for increased efficiency in mating operations; lowering the risk of mechanically induced damage leading to failure by adding mating aids and levels of automation to the process. Time and engineering effort will one day yield systems and elements that will allow for automated or auto-pilot coupling of wet mate flying lead connections and a number of teams are engaged in resolving this challenge around the world today.

Today, however, 'Reliability Engineering' has paved the way forward for qualifying enhanced material systems for subsea use. Design enhancements featuring upgraded materials, mating aids and process controls have recently been introduced in production, which will positively impact ROV operational efficiency through more efficient connector mating times.

In particular, attention has been given to optical and hybrid wet mate connectors and assemblies. Similar to hydraulic or

electrical flying leads, a remotely operated vehicle (ROV) mates and de-mates optical connectors, or optical flying leads on subsea trees, UTAs and manifolds. These connectors provide optical communication for long step-outs, high bandwidth data multiplexing or optical sensing applications. Teledyne Oil & Gas, for example, has deployed over 6400 optical wet mate connectors and it is understood that ROV intervention time due to operator variability and environmental conditions such as current and visibility, are factors that can significantly increase costs.

In the world of reliability, failure modes, effects and criticality analysis (FMECA) exercises are often used to illustrate potential deficiencies in a design or process, and suggest improvements. High risks are identified and then mitigated to be swiftly reduced to medium and eventually low risks. The results yield more robust designs, and more efficient processes. Teledyne Oil & Gas implements FMECA exercises during the design (D-FMECA), manufacturing process (P-FMECA) and operational (O-FMECA) phases. Critical to improving the ROV handling of the wet mate connectors was the O-FMECA, where customers were invited to give feedback about how installation, storage and product end-use could be improved. In a recent review, an O-FMECA exercise of the optical wet-mate connector compiled a suite of design enhancements to optimise ROV mating efficiency and reduce operator intervention time, thus lowering total installed cost.

### Making a connection

In order to prevent damage to connector components due to misalignment, proper alignment must take place before the connector faces come into contact. The most important improvements were made to improve initial alignment and latching indication. ROV pilot experience and subsea conditions can contribute to variability during the intervention process. In some of the worst cases mating operations have been reported to take in excess of 30 minutes per connection.

In the legacy optical connector design, the acceptance angle to ensure a successful mate was  $\pm 5^\circ$ . During a review of the connector O-FMECA, a major operator challenged Teledyne to improve this operational aspect of the design and make the mating process more efficient. Working with the customer, a new gross alignment funnel (GAF) was designed to increase the effective acceptance angle to  $\pm 30^\circ$  to overcome severe approach angles of ROV connectors during mating. Constructed from seawater compatible and field-proven polymer, the gross alignment funnel is physically attached to the bulkhead connector and provides guidance of the ROV flying connector half during mating. Easily installed onto an existing optical connector bulkhead mounted connector, the GAF significantly reduces ROV operator variability, ultimately resulting in more efficient mating/de-mating times, and lower overall operator cost while eliminating the occurrence of operator induced connector shell damage through gross alignment before the connector shells make contact.

In many cases, mating is further complicated when the bulkhead mounted connector is shrouded by a protective bucket or mounting plate, so the enhanced latching indicator (ELI) system mounts to the flying lead connector and presents visual mating indication closer to the handle area of the ROV connector. When unmated, four high-visibility, yellow indicators rest inside the handle and when a successful mate occurs, the indicators extend out, delivering to the ROV pilot an indication of a positive latch. The ELI is easily

retrofitted onto connectors, which are not yet deployed subsea but are already in the field. When used with the GAF, the ELI provides additional fine alignment registration.

The GAF and ELI have been successfully qualified for performance in a subsea environment. In all tests conducted, the GAF has demonstrated acceptable performance and is fit for purpose for either a rolling seal optical or nautilus electrical connector and has become part of the standard kit for all hybrid and optical flying lead assemblies.

The inner design components of the connector were also scrutinised for enhancements to robustness for subsea operations. The centre actuator of the bulkhead connector acts as a spring and performs a crucial role in the movement of the seals of the connector. The O-FMECA revealed an opportunity to increase the yield strength of the actuator material to improve overall connector robustness.

An enhanced actuator material was chosen as a replacement for the legacy actuator material. No changes to form, fit or function of the actuator part were made with this improvement. Comparison of data resulting from testing of the two actuator materials was conducted. It was determined that throughout high mate number and accelerated stress testing, the enhanced grade actuator retained its original profile better than the legacy actuator and demonstrated less deformation from excessively abnormal mating than the legacy actuator material. Thus, the use of the enhanced grade material provides significantly increased design and operational margin over the legacy actuator material. Although the legacy actuator remains adequate for the connector's refurbishment cycle of 100 mates, the enhanced design's durability is desired for upgrading connector systems,

extending the connector lifecycle and protecting the connector from mating operations that are outside of the desired design envelope (speed, angle of approach, flying connector condition).

Industry reception to these design improvements has been overwhelmingly positive, with ROV intervention times, in some cases being reduced from 30 minutes down to less than 5 minutes with a dramatic reduction in operator induced damage during mate/de-mate operations.\*

### Conclusion

Though these design improvements ease the mating process and partly mitigate the effects of operator variability, the requirement for connector mate/de-mate training and simulation must be emphasised to complete the operational efficiency and risk reduction equation. All personnel tasked with mating optical wet mate connectors should be properly trained and familiarised with the appropriate user manuals, in order to prevent damage during mating and de-mating of connectors. This is especially important when ROV-configured connections are to be mated manually as the process calls for precision mating operations associated with proper mating speed and considerable mating forces. A well-written user manual provides checklists for inspections of both the bulkhead plug and the flying lead prior to mating of the connectors. These checklists should be utilised each time a connector is to be mated. Connector manufacturers must support technical training programmes and training aids for all field and programme engineering personnel, upon request. ■

### Note

\*Qualification documentation is available upon request.

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THE  
**GROWING**  
ROLE FOR  
**EXPANDABLES**

## Jerry Fritsch, Enventure, USA, discusses high performance solid expandables for HPHT and deepwater operations.

In the 15 years that solid expandable technology (SET) has been available, more than 1600 systems have been installed globally. This equates to enough solid expanded pipe to reach from earth to the International Space Station and beyond – over 260 miles (Figure 1). A growing portion of this pipe is designed for HPHT applications.

Over 14 000 ft of specialised SET pipe has been installed in high-pressure land, shelf and deepwater wellbores. Each application added significant value to the wellbore construction process by resolving unique problems, both in drilling and repairing the well. Bottomhole temperatures in these extremely deep wellbores can exceed the 400 °F (200 °C) rating of standard SET systems. To address these extremes, a 7 5/8 in. high-temperature (HT) SET system has been developed that increases SET ratings by 50 °F (10 °C) to 450 °F (230 °C).

In the challenging operational and economic conditions presented by HPHT wellbore construction, the use of these HP and HT SET systems allow an operator to add additional casing strings that may be critical in reaching the planned depth with the optimal wellbore diameter.

### High-performance solid expandables

**The challenge:** initial need for a high-performance solid expandable  
The need for a high-performance expandable was initially recognised for a North Sea operator drilling HPHT wells in the Central Graben Area. The operation required an additional casing string to isolate high-pressured shales prior to drilling a lower pressure interval immediately below. The drilling was being executed from a wellhead platform that had been set some years earlier; therefore, adding an additional string to isolate the shales or changing the upper and/or intermediate casing strings were not options (Figure 2). In collaboration with the operator regarding the use of a solid expandable liner to cover the high-pressured shales, it was calculated that the pressure when drilling the lower pressure interval would create a collapse scenario with a negative differential of 2000 - 3000 psi on the expandable liner.<sup>1</sup> This differential could exceed the rating of a standard solid expandable liner. Thus, the need for a high-performance expandable liner was determined.

### Development of a high performance solid expandable

Work began immediately to develop a 7 5/8 in. SET system to provide at least a 50% increase in collapse rating. Development of the HP SET was completed in compliance with ISO9001 quality standards. Early testing verified that, in order to increase the collapse rating, an increase in wall thickness would be required. To attain the necessary collapse rating and retain optimal post-expanded diameter, a 0.500 in. wall thickness was selected. The thicker wall of the HP design (0.500 in. wall versus 0.375 in. for the standard system) slightly reduced the post-expanded inside diameter of the liner; however, it provided an acceptable diameter for drill-ahead diameter and running the next casing string.

The HP pipe was manufactured to proprietary product specifications using electric resistance welded (ERW) tubing produced by US Steel (formerly Lone Star Steel) and Nippon Steel. The manufacturing specifications met, and in certain instances exceeded, the requirements of API 5CT for L-80 casing. For example, SET casing has a tighter wall

tolerance requirement of < 8% (versus API's 12.5% tolerance) and higher minimum-impact resistance values.

### 7 5/8 in. HP SET specifications and first installation

The 7 5/8 in. HP SET was shipped to location was run, cemented and expanded in a 17.5 ppg OBM environment to cover the known high-pressure shale section at a depth below 15 000 ft. This first 7 5/8 in. HP SET system had a pre-expanded length of 1665 ft. After the liner was installed, the shoe was drilled out and mud weight reduced. These operations exerted more than 2000 psi collapse differential pressure across the post-expanded liner.<sup>2</sup> Drilling continued to the next casing point where the planned 6 5/8 in. conventional casing was run and cemented. The wellbore was then successfully drilled to TD and completed with the planned tubular diameters (Figure 2).

### Additional installations and sizes of high performance solid expandables

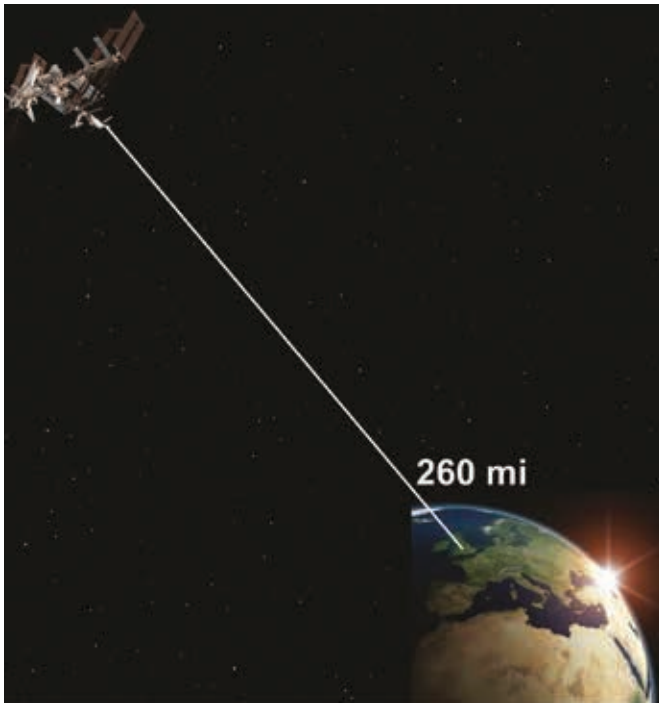
Since the installation of the first 7 5/8 in. HP SET, additional applications were identified that required enhanced mechanical ratings. To support these special applications, both 11 3/4 in. and 8 5/8 in. HP SET Systems have been developed and qualified (Table 1).

The 11 3/4 in. HP system was first installed in a deepwater Gulf of Mexico well. Subsequently, another system was run in a Caspian Sea well. The recently developed 8 5/8 in. HP system was qualified for an operator with a specific challenge in the North Sea; the system has been a contingency on their last two wells, but it has not been run yet. To date, a total of 11 HP SET systems have been installed, five of which have been in deepwater Gulf of Mexico (Table 2).

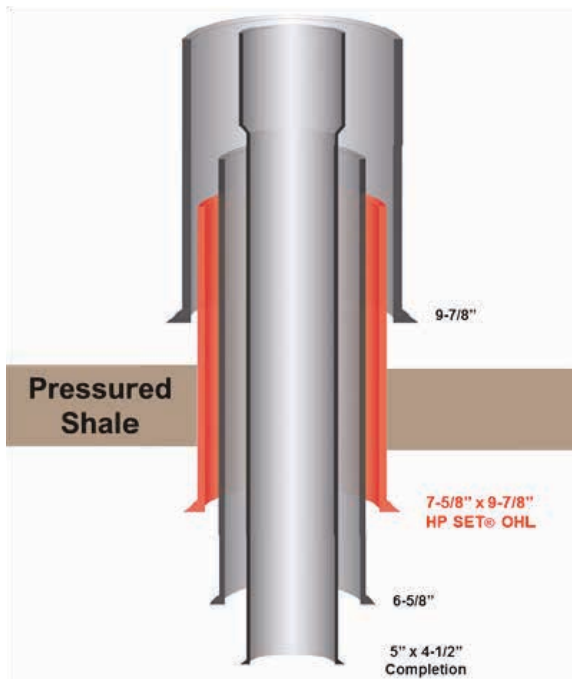
### Gulf of Mexico deepwater applications using high-performance expandables

#### Well repair installations

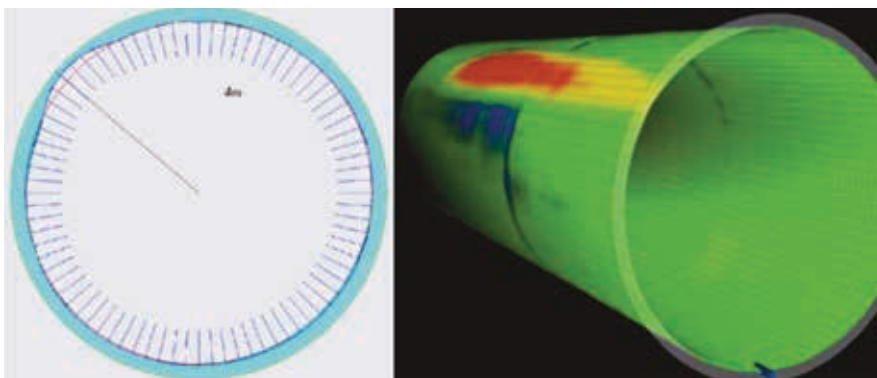
The first and second installations of HP SET in the Gulf of Mexico deepwater were used to repair the existing casing. The first liner was a 333 ft (pre-expanded) installation used to cover a section of 13 3/8 in. base casing that experienced significant wall loss above a whipstock due to drill pipe rotation during sidetracking operations.<sup>2</sup> The wall loss was identified during a required regulatory casing calliper inspection log (Figure 3). After log evaluation, an 11 3/4 x 13 3/8 in. HP SET was selected as the best option due to the liner's ability to restore both pressure and mechanical integrity to the wellbore with its 0.618 in. pre-expanded wall. Of utmost importance was the system's ability to provide the required post-expanded diameter to continue the wellbore construction with the planned casing programme. Following installation and successful pressure testing, the wellbore was approved by regulatory authorities to resume sidetracking operations. The well was successfully sidetracked, drilled to total depth and completed.



**Figure 1.** Expanded pipe installations reach from Earth to beyond the International Space Station.



**Figure 2.** Pressured shale requiring HP SET.



**Figure 3.** Wall loss due to drill pipe rotation wear.

The second Gulf of Mexico deepwater application used a 7 5/8 x 9 5/8 in. HP SET system to cover an unwanted set of perforations. The HP SET liner pre-expanded length was 46 ft. Following the installation and pressure test, the well completion was re-run and the well returned to production. Subsequent HP SET installations in the deepwater Gulf of Mexico have all been drilling liners utilizing the 7 5/8 in. system.

### Drilling installations

After the first 7 5/8 in. installation, additional HP SET systems that have been run outside the Gulf of Mexico deepwater, including one 11 3/4 in. and two 7 5/8 in. HP SET systems (Caspian and Middle East shelf operations, respectively) and two 7 5/8 in. HP SET systems run in the Western Hemisphere (an onshore sidetrack operation in Louisiana) and one additional Gulf of Mexico shelf installation.

The first Gulf of Mexico HP SET used in a drilling application was run in a subsalt exploration well. The objective of an exploratory wellbore is to reach planned depth with adequate diameter to properly evaluate the potential reservoir. As an exploratory wellbore progresses, there can be numerous anomalies involving pore pressures, fracture gradients and wellbore stability. In this wellbore, the operator experienced significant wellbore instability at the base of the salt. Due to insurmountable challenges, including loss of an entire BHA that required a sidetrack, the 9 5/8 in. conventional casing was 3400 ft higher than originally planned (Figure 4).

The operator needed a solution that would preserve wellbore diameter and enable the planned depth to be reached. A 7 5/8 in. x 9 7/8 in. HP SET was ideal as it provided a post-expanded drift of 7.524 in. This diameter enabled the use of a rotary steerable assembly to drill an additional 5000 ft of directional hole below the HP SET liner, allowing the planned TD objective to be reached and evaluated. The liner had a pre-expanded length of 1936 ft and provided for a subsequent 7 in. liner option.

Two additional 7 5/8 in. HP SET liners have been run as part of sidetracking operations in the deepwater Gulf of Mexico. A sidetracking operation has a fixed starting diameter and a required diameter at TD. This is an optimal application for SET liners as the expandable can provide a crucial additional casing string. Adding the HP SET greatly reduces the risk of not reaching TD due to changing and unknown pore pressures/fracture gradients.

In both installations, the HP liners exceeded the requirements of the wellbore conditions and enabled the sidetracked wellbore to reach the planned objective. The first liner was 2105 ft and the second 2566 ft in pre-expanded length.

### HP value

The first Gulf of Mexico deepwater HP SET cased-hole liner effectively saved a wellbore that regulatory requirements had condemned due to base casing drill pipe wear. The SET liner restored integrity, leaving a post-expanded diameter enabling the well to be drilled to TD and completed with the originally designed casing size. This installation from a deepwater tension-leg platform (TLP) retained a production slot of immense value.

The first HP SET drilling liner run in Gulf of Mexico deepwater enabled the construction of an exploratory wellbore to TD despite having a critical 9 5/8 in. casing string set 3400 ft higher than planned. The HP SET liner avoided a sidetrack and the risk of having to start the wellbore over. Loss of the deepwater wellbore at this point would have been a huge expense.

Both these wellbores were exploratory with a primary objective of reservoir evaluation upon reaching the targeted depth. However, the magnitude of the capital investment in Gulf of Mexico deepwater operations makes it an important secondary objective to be able to produce the well if there is a discovery. In one of these wells, a discovery was made and the well was completed and successfully put on production due to the optimal wellbore diameter provided by the HP SET liner.

The two most recent Gulf of Mexico deepwater HP SET installations were used in sidetracking operations. Both wells were sidetracked out of 9 5/8 in. base casing; however,

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they were completed with 7 in. versus 5 in. conventional casing at TD due the application of HP SET. Given the difference in the volume of hydrocarbons that can be produced through 7 in. versus 5 in. casing (a 100% increase in flow area), the value of the larger wellbore can potentially exceed hundreds of millions of dollars.

### High-temperature solid expandables

As wells are drilled deeper, bottomhole temperatures are going to increase. Over the past 24 months, operators around the world have requested SET systems that can handle temperatures up to 450 °F (230 °C).

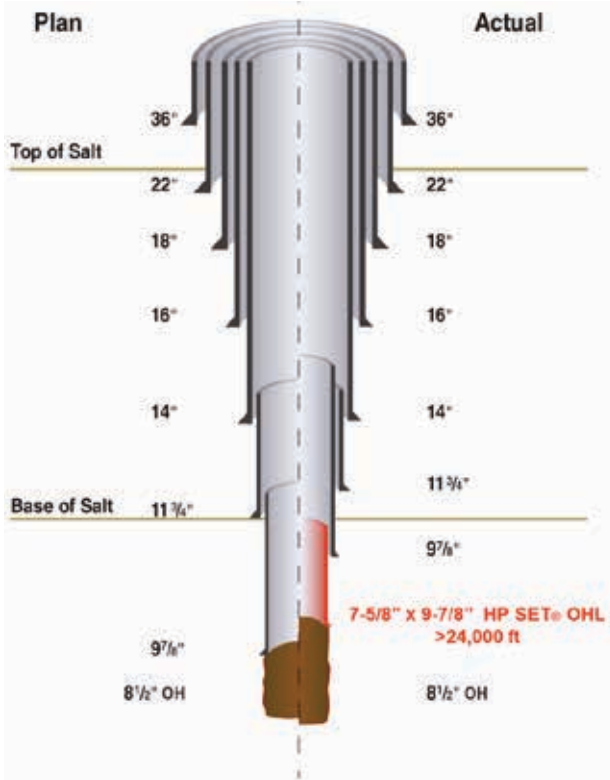


Figure 4. First HP SET drilling liner in Gulf of Mexico deepwater well.

SET liner system	Weight (lb/ft)	Wall (in.)	Internal yield (psi)	Collapse (psi)
7 7/8 x 9 7/8	29.7	0.375	6050	2660
7 7/8 x 9 7/8	39.0	0.500	8050	4690
8 5/8 x 10 3/4	32.0	0.352	5100	1760
8 5/8 x 10 3/4	44.0	0.500	7200	3830
11 3/4 x 13 3/8	47.0	0.375	4370	1200
11 3/4 x 13 3/8	74.6	0.618	7150	3780

Job no.	HP SET Liner size	Location	Environment	System	Length (ft)	Depth (ft)	Mud weight (lb/gal)	Deviation (°)
1	7 7/8 x 9 7/8	North Sea	Shelf	Drilling	1665	>15 000	17.5	90
2	11 3/4 x 13 3/8	GoM	Deepwater	Repair	333	<10 000	14.2	0
3	7 7/8 x 9 7/8	Middle East	Shelf	Drilling	1788	>10 000	10.5	45
4	7 7/8 x 9 7/8	GoM	Deepwater	Repair	46	>15 000	13.1	20
5	11 3/4 x 13 3/8	Caspian	Shelf	Drilling	1180	>10 000	16.1	35
6	7 7/8 x 9 7/8	GoM	Deepwater	Drilling	1936	>20 000	16.2	0
7	7 7/8 x 9 7/8	Middle East	Shelf	Drilling	505	>10 000	8.6	30
8	7 7/8 x 9 7/8	GoM	Shelf	Drilling	1100	>10 000	16.7	0
9	7 7/8 x 9 7/8	GoM	Deepwater	Drilling	2105	>10 000	11.3	53
10	7 7/8 x 9 7/8	USA	Land	Drilling	1124	>10 000	16.4	0
11	7 7/8 x 9 7/8	GoM	Deepwater	Drilling	2566	>10 000	12.1	66

To accommodate this requirement, a testing/qualification programme was commissioned to elevate the temperature rating of the 7 7/8 in. SET system to 450 °F.

The 7 7/8 in. SET system was selected as the first size to be qualified to 450 °F because most wellbores with a high bottomhole temperature are quite deep. The use of a SET system will likely occur after intermediate casing has been run and a smaller hole/casing size needed. However, larger SET system sizes can be qualified to high temperature as the need arises.

With the elevated temperature, all components of the SET system were evaluated for thermal degradation.

The 7 7/8 in. SET system was successfully qualified to 450 °F operations. Additional high-temperature components, unique to this system, were added to inventory. This system is awaiting trial.

### Conclusion

The development of HP SET with increased mechanical ratings and maximum temperatures extends expandable capabilities to address the growing extremes of HPHT wellbore construction.

Greater pressure ratings of HP SET enable the use of expandables in wellbores where pore pressure exceeds the mechanical rating of standard SET liners. The most common solution has been to move the solid expandable up or down one SET position in the casing design to alleviate the pressure issue.

However, some scenarios preclude that option, as in the example of the first HP SET where the wellhead platform was already in place. Another common scenario is when a well is being drilled and casing size change is no longer an option.

Three HP SET sizes (11 3/4 in., 8 5/8 in., and 7 7/8 in.) provide a range of options in dealing with unpredicted pore pressure changes.

HP SET liners have also demonstrated their value in remedial operations for restoring the pressure integrity of wellbores with severe casing wear, or to cover unwanted perforations to restore production.

For high-temperature applications, a 7 7/8 in. SET is qualified and rated to 450 °F to address bottomhole extremes.

As wellbore construction continues to become more intricate, operators will continue to look for options to help them achieve their wellbore and economic objectives. Solid expandable systems have for the past 15 years

greatly enabled their success. It is reasonable to expect that the ever-increasing demands on solid expandable tubulars as an enabling technology will propel its evolution and adaptation to further enhance HPHT wellbore construction.

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# EVALUATIONS ZIPPING

## ALONG

**Sudhendu (Kash) Kashikar and Karl Harris, MicroSeismic, Inc., USA, compare completion methodologies and optimising production using microseismic-based completions evaluation.**

**S**uccessful development of unconventional resources boils down to two processes – reservoir stimulation through hydraulic fracturing, and hydrocarbon recovery. These two processes are inherently coupled since hydrocarbon recovery depends upon effective stimulation treatment. The challenge facing the industry is how to evaluate and quantify the effectiveness of hydraulic fracturing. There are several parameters that influence the effectiveness of the stimulation; including fracturing sequence, fluid and proppant volumes, and rock property variations along the wellbore. Microseismic-based completions evaluation tools provide insight to answer this question through a comprehensive and deterministic analysis that measures the proppant filled fracture volume and how it varies based on different treatment parameters. This allows operators to make informed decisions when optimising completions to maximise recovery for every well.

Operators are focused on finding answers to improve completions optimisation. Three common questions that continue to be asked and assessed through microseismic are as follows:

- ▶ Does the sequence of zipper fracking have an impact on the stimulated rock volume (SRV)?
- ▶ What is the impact on SRV when using slickwater versus gel, and can fluid volumes be optimised?
- ▶ Is the use of diverters effective in activating additional perf clusters and reducing stranded reserves?

The examples discussed in this article show how using microseismic-based completions evaluation can quantitatively and deterministically answer these questions and help

operators evaluate various treatment options without waiting for several months of production data.

## Accurate evaluation

MicroSeismic, Inc.'s completions evaluation services perform diagnostic analysis of microseismic data enabling accurate evaluation of the fracture treatment. The analysis helps the operator to understand the fractures created during hydraulic fracturing. It reveals how long the fractures are, in what direction around the wellbore they have propagated, how complex the fracture network is, and what portion of the fractures are filled with proppant.

The basis of this method involves acquiring and processing microseismic data during hydraulic fracturing to identify fracture locations, magnitudes and source mechanisms. From there, a magnitude-calibrated discrete fracture network (DFN) is computed which shows the orientation and size of each fracture. Based on this magnitude-calibrated DFN, a mass balance model is used to determine what proportion of fractures contain proppant and should, therefore, be productive. The resulting Productive Discrete Fracture Network (P-DFN) and Productive Stimulated Rock Volume (P-SRV™) allow for quantifying optimal well spacing, stage lengths and treatment efficiency. Analysis of this propped fracture volume provides a method that can directly compare the effectiveness of various treatment options by measuring the effective fracture height, fracture length and propped volume distribution away from the wellbore.

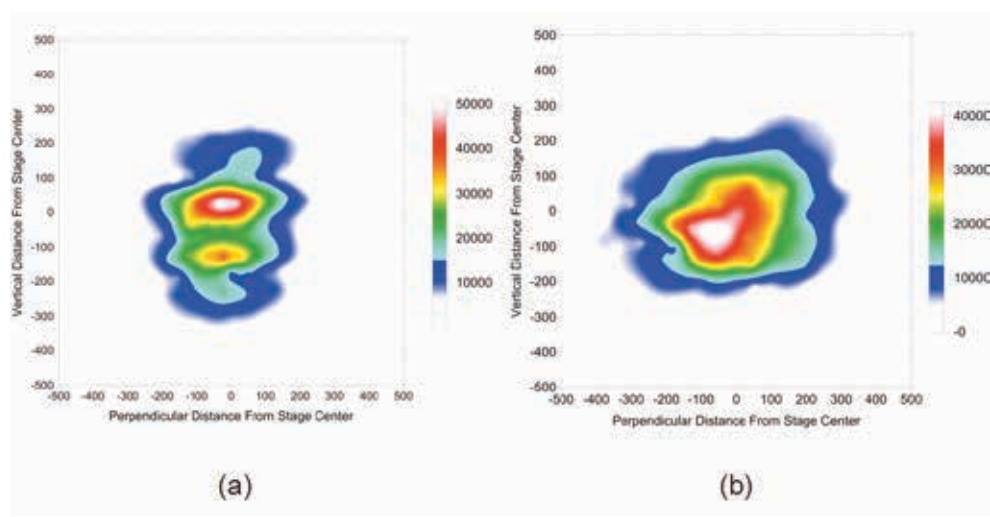
## Understanding zipper fracs

Over the past three years, zipper fracking has taken the unconventional shale market by storm. In comparison to completing an entire well at once, this method alternates the completion from well to well, one stage at a time, back and forth similar to a zipper down the length of the wellbore. This method has become popular among operators because the logistics allow for massive improvements in completions efficiency. However, it is important to also understand the effect on completions effectiveness and ultimately, production.

Most signs point to improved production from the zipper fracking method, but there is still a question mark around whether or not the outer wells should be treated before the inner wells, or vice versa. One example where the P-DFN is compared when the frac order is changed is discussed below. All three wells in both cases had a similar completion and treatment with the exception of fracking order: completion a) outer two wells fracked before middle well, completion b) middle well fracked before two outer wells.

To properly evaluate the impact of treatment order, it is necessary to look not only at the microseismic events, but more importantly at the proppant-filled fracture volume achieved from each scenario.

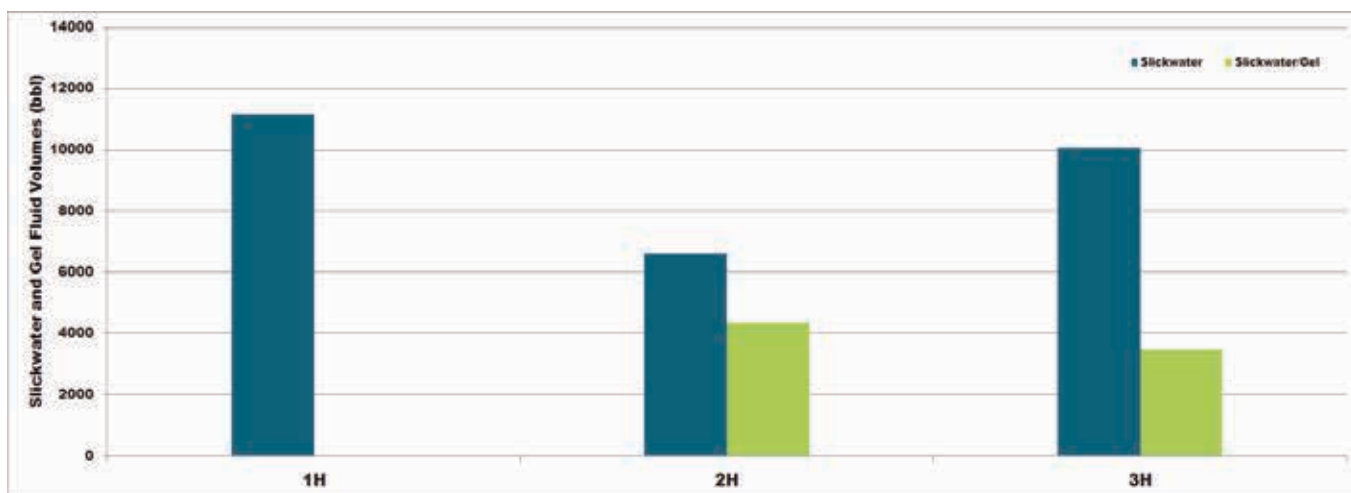
Figure 1 shows a vertical 'toe view' of the resultant propped fracture volume. As shown in Figure 1(a), when the middle well is treated after treating the outer wells, the overall propped fractures are tightly constrained by the outer wells. The fracture growth is larger in the vertical direction compared to the middle well being treated first, shown in Figure 1(b). In this case, the operator achieved sufficient perpendicular coverage in Figure 1(a) but too much vertical coverage, suggesting that in this area, treating the middle well first and using lower volumes of fluid will yield effective stimulation while also saving time and money.



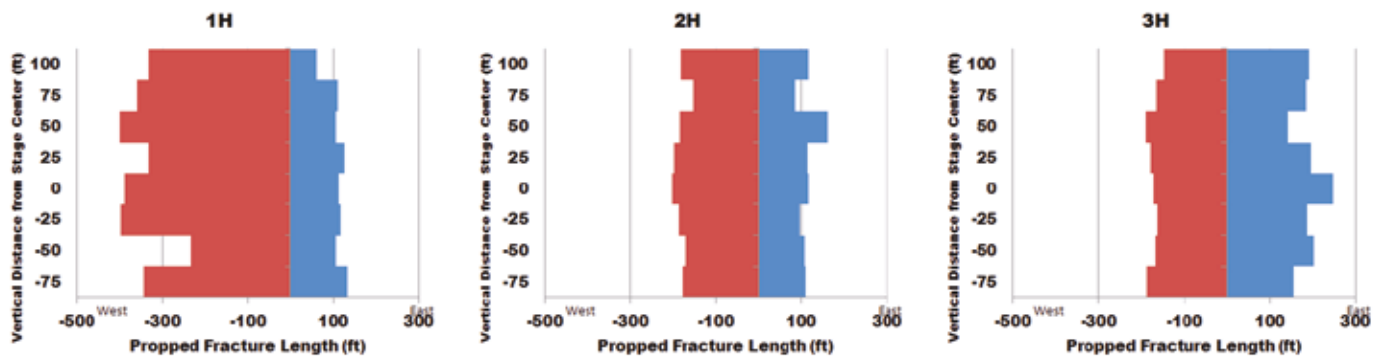
**Figure 1.** Toe view of the completed middle well showing the fracture volume as a function of treatment order. (a) Middle well treated last. (b) Middle well treated first.

## Comparing slickwater versus gel treatment

An example from the Marcellus Basin in Figure 2 illustrates where some stages were treated with slickwater only or with a hybrid treatment of slickwater followed by gel. Three wells on the same pad were treated using different amounts of fluid and gel. Well 1H was treated with only slickwater, while wells 2H and 3H were treated with hybrid fluids. Well 3H had 20% more total fluid volume compared



**Figure 2.** Treatment summary for a three well pad in the Marcellus.



**Figure 3.** Comparing propped fracture geometry for various treatments.

to well 2H. Other treatment parameters, such as treatment rate and total proppant per stage, were similar in all cases.

Well 2H, treated with hybrid fluids, showed a significantly higher number of fractures compared to well 1H. While the treatment order may influence some of the increase in total number of fractures, a significant portion of the fractures are a result of treatment with a higher viscosity fluid. Figures 3(a) and 3(b) show the corresponding proppant filled fracture dimensions in a vertical cross section – looking at both the vertical growth as well as the lateral growth. Well 1H, treated only with slickwater, shows significantly longer fractures compared to the hybrid treatment. This is consistent with modelling results that have been studied previously.

Wells 2H and 3H, Figures 3(b) and 3(c) respectively, were both treated with hybrid fluids, but well 3H had 20% higher fluid volume. The length of the proppant filled fractures from well 3H exceeded that of well 2H, resulting in a 10% increase in the P-SRV, or an additional 50 000 bbls of recoverable reserves per well. The evaluation of this completion method suggests that the higher volume of hybrid fluids used in well 3H is better suited for this particular section of the reservoir.

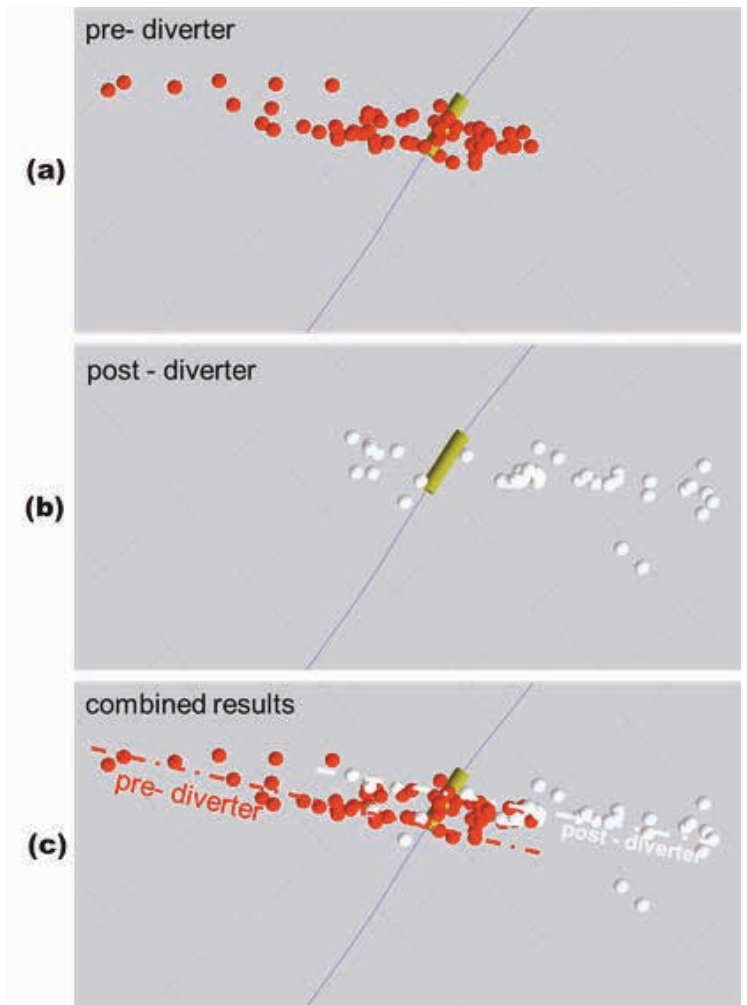
### Effectiveness of diverters

Microseismic monitoring is also a powerful tool in evaluating the effectiveness of diverters to improve fracture geometry and activate additional sets of non-dominant perforations. Figure 4 displays the results both pre- and post-diverter from two stages treated simultaneously with the diverter pumped halfway through the treatment.

From Figure 4(a), it is clear that the pre-diverter treatment generated more fractures in the lower part of the stage, and most of the fractures were skewed to the west of the wellbore. Figure 4(b) shows the fracture locations post-diversion. A noticeable change is evident in the activation of additional perf clusters and the direction of fracture growth. Figure 4(c) shows the combined results from pre- and post-diversion. In this particular completion, the diverter method was successful in plugging the lower perf clusters and forcing the treatment fluid into new perf clusters. This allowed the operator to reduce the number of plugs used and wireline trips made while maintaining the same SRV and access to recoverable reserves.

### Summary

In today's commodity price environment, it is more important than ever for operators to focus on optimising production from every well. In order to continue to improve production, well completions must be compared, evaluated and improved upon over time. Microseismic-based completions evaluation services can quantitatively and deterministically answer many of the questions operators are facing when trying to optimise production. This method of completions evaluation is the only available data-driven methodology to understand



**Figure 4.** Evaluating the effectiveness of diverter use.

what is actually happening during hydraulic fracturing and to use science to improve production.

In the particular examples studied above it was found that:

- ▶ During zipper fracking, treating outer wells before inner wells achieved optimised frac geometry while reducing treatment costs.
- ▶ Hybrid fluids yielded more fracture complexity, and increasing the volume of the hybrid treatment by 20% resulted in 50 000 bbls of additional recoverable reserves per well.
- ▶ Pumping diverters allowed for a reduction in completion costs while maintaining SRV.

The operators in these examples were quickly able to evaluate different treatment methods and improve the quality of completions without waiting for several months of production data – saving time and money, and ultimately maximising asset value. ■

# NO



# NO PROBLEM

**G**rowing demand for water used in hydraulic fracturing is contributing to the challenge that water managers face in many regions. Many water plans have quickly become outdated, as demand for water for shale oil and gas development, as well as for municipal, agricultural and recreational purposes is increasing. Currently, many oil companies and operators acquire fresh water for fracturing treatments on the front end, and pay to dispose or transport the flowback or produced water on the back end, increasing the cost of the hydraulic fracturing job.

Addressing the issues outlined above is TriFrac-MLT™, a newly developed fracturing fluid system that uses 100% untreated produced water, reducing the strain on a valuable resource and reducing the upfront costs of purchasing fresh water. In addition, the back end costs are significantly reduced by transporting produced and/or flowback water to locations for re-use rather than to disposal well(s), sometimes located hundreds of kilometres away.

### **Save water, save the environment**

Many states in the US are home to thriving unconventional resource plays where hydraulic fracturing is unlocking the potential of hydrocarbon bearing formations. The shift from vertical to horizontal fracturing of wells

has brought with it the need for greater quantities of water, and greater consideration of drought conditions.

Measures to improve water efficiency across the shale development water lifecycle should be top priority. If water immediately flowing back from a hydraulically fractured well (flowback) or rising back to the surface over time (produced water) is of sufficient quality and quantity, reusing or recycling (requires treatment) should be considered. Recycling technology has improved in the past few years, offering both centralised and distributed treatment solutions that can provide operators with water quality high enough for reuse in future hydraulic fracturing operations. Reused water can also be used for other industrial and agricultural purposes, provided it has been sufficiently treated and is authorised by regulators.

Several analyses lay out the compelling economic case for collaborative or centralised reuse:

- ▶ In the Bakken, cost reduction per barrel of oil of up to 46% could be realised, through advanced water reuse planning, equivalent to approximately US\$350 million annual savings for the region.
- ▶ The Niobrara formation could realise up to 24% cost savings, resulting in US\$60 million regional savings. Savings are lower in this region

BENJAMIN CARLIER AND JOSE GARZA, TRICAN, NORTH AMERICA, EXAMINE A CROSSLINKED GUAR-BASED FLUID SYSTEM THAT USES 100% REUSED WATER IN AN EFFORT TO CONSERVE FRESH WATER IN THE HYDRAULIC FRACTURING PROCESS.



compared to the Bakken due to lower produced water volumes and lower wastewater disposal fees.

- ▶ In the Eagle Ford, an analysis of an operator's plans to drill approximately 1400 wells over a five year period found a cost savings of 44% by pre-planning and establishing a centralised reuse system, which involved an initial outlay of US\$184 million, but a net saving of US\$1.2 billion over a five year period.
- ▶ In the Marcellus, an estimated US\$150 000 saving per well could be realised (~10% of total costs) by 100% reuse of flowback water, which minimises trucking wastewater long distances often across the border to Ohio.

For these cost savings to be realised, operators must be willing to take a longer-term view (e.g. five years) and commit to up-front capital expenditures. The economics can be compelling. Proactive water planning can potentially save 10 - 46% of well development costs, which can result in tens of millions of dollars in regional savings.

### Addressing key issues surrounding water conservation

To reduce fresh water requirements and meet the water planning and treatment needs of operators, TriFrac-MLT was developed.

TriFrac-MLT is a technology specifically designed to address several key issues facing the E&P hydraulic fracturing industry: (1) to develop fracturing solutions that will reduce the use of freshwater resources, (2) to provide a fracturing solution that reduces the costs associated with treating flowback and produced water to conventional reuse standards, (3) to simplify the logistics associated with produced water reuse programmes, and (4) reduce or eliminate the secondary waste streams that are created by treatment processes that concentrate the waste and minerals present in the produced water. This gives the benefit of not having to treat the produced water as flowback water.

The following section looks at the water cycle of hydraulic fracturing and how this system positively influences each step:

- ▶ **Water acquisition:** The system uses 100% untreated produced or flowback water instead of fresh water required for conventional fracturing fluid systems. It uses common fracturing fluid additives, and no fresh water is needed. TriFrac-MLT can handle water with total dissolved solids (TDS; the amount of soluble materials present in a given water sample) exceeding 300 000 mg/l, hardness exceeding 30 000 mg/l, and boron levels of more than 500 mg/l. It operates at a broad temperature range, from 120 °F (49 °C) to 300 °F (149 °C).

Trican normally recommends a 25-micron filtration for the reused water. After the decision is made to filter the water system, it is pumped like any other fluid in the field.

- ▶ Chemical mixing: The flowback or produced water is combined with chemical additives and proppant to make the hydraulic fracturing fluid. Adding TriFrac-MLT enables rapid hydration of the additives (gellant). Because it crosslinks at a temperature as low as 45 °F (7 °C), it reduces potential fluid heating costs. It is a low pH system (4 to 6) so there is a reduction in the scaling tendencies

Water source	TDS concentration	TDS concentration (mg/l)
Fresh		<1000
Slightly saline		1000 - 3000
Moderately saline		3000 - 10 000
Saline		10 000 - 35 000
Sea water		>35 000
Produced (Bakken formation) Williston Basin North Dakota		220 000 - 350 000

Element	Spec for velocity frac with FR-15	Spec for Borate Stratum-RW	Spec for TriFrac-MLT
Chlorides	>150 000	30 000	>150 000
Sodium	>100 000	20 000	>100 000
Ca (mg/l)	20 000	500	20 000
Mg (mg/l)	20 000	500	20 000
Ba (mg/l)	8000	1000	20 000
Fe (mg/l)	150	10	Higher than 300
SO <sub>4</sub>	1500	1500	1500
HCO <sub>3</sub>	1500	1500	5000
Boron (mg/l) pH	Higher than 500 pH > 3.0	100 Ideal 5.0 - 8.5	Higher than 500 pH > 3.0
TDS (mg/l)	>300 000	120 000	>300 000

Test number	1	2	3
Fluid	20 lb crosslinked CMHPG in synthetic brine per Table 4.	25 lb crosslinked guar-based derivative in synthetic brine per Table 4.	30 lb crosslinked CMHPG in synthetic brine per Table 4
Breaker	0 ppt in pad and 0.75 ppt in slurry	0.5 ppt in pad and 2.0 ppt in slurry	0.75 ppt in pad and 2.0 ppt in slurry
% Regained conductivity	90	80	85
% Inverse beta factor	72	80	91

Well type	Produced water					
Anions	mg/l	meq/l	Cations	mg/l	meq/l	
Chlorides	170711.30	4814.06	Sodium	68010.00	2958.44	
Sulfate	493.80	10.27	Calcium	17550.00	877.50	
Bicarbonates	61.00	1.00	Magnesium	1259.00	103.62	
Carbonates	0.00	0.00	Barium	10.70	0.16	
Hydroxide	0.00	0.00	Strontium	1210.00	27.62	
Phosphate	0.00	0.00	Potassium	583.70	14.94	
Silica	0.00		Iron	150.70	8.09	
			Chromium	0.00	0.00	
pH	5.32		Manganese	10.92	0.60	

of the well. The salt concentration in the produced water remains practically the same, even after multiple reuses of the produced water. Per cycle, only around 0.2% of polymer is added.

- ▶ Well injection: Pressurised hydraulic fracturing fluid is injected into the well. The system is pumped on-the-fly. Because the fluid system has a delayed crosslinker (and has a customisable breaker schedule), its viscosity can be optimised. This reduces pumping costs, because less energy is required to pump the fluid down the well. The fluid has some initial viscosity but becomes highly viscous once it is down the well and feels some heat from the formation.
- ▶ Flowback and produced water: The system is extremely tolerant of high salt content and other contaminants, allowing for the reuse of untreated flowback water (including water containing boron), and produced waters from oil and gas wells. During operation the pH level of the base fluid is brought to ~6 to allow quicker hydration of the gel. The longer the residence time allowed for hydration, the higher the viscosity generated will be in the system.
- ▶ Wastewater treatment and waste disposal: The need to pre-treat the reused water (and therefore also the requirement of water treatment equipment) is eliminated. It has a positive impact on costs associated with acquiring fresh water (which can be upwards of 185 000 gal. [700 m<sup>3</sup>] per stage), and disposing of produced or flowback waters. The fluid can be handled multiple times and minimal secondary waste streams are generated, further enhancing the economic, environmental and logistical benefits of this technology.

## Regained conductivity testing

Proper rheological characterisation of the fracturing fluid is crucial to the success of the stimulation treatment. Trican performed laboratory testing of the fluid characteristics in untreated produced water from the Bakken formation. Regained conductivity testing was completed in a third-party laboratory. Conductivity values were made with all cells containing 2 lb/ft<sup>2</sup> 20/40 CARBOProp at a closure stress of 5000 psi. Tests were performed at 265 °F (130 °C) followed by a cleanup phase after 15 hours of shut-in. Sandstone cores were used to simulate (~2 mD) formations. Conditioning of the fluid entailed pumping from intensifier pumps to a tubing section where it was sheared at near 1000 sec<sup>-1</sup> for about 3 minutes. Once the fluid temperature reached 250 °F (121 °C) at a

shear rate of 40 - 50 sec<sup>-1</sup>, the fluid was flowed through the test cell and allowed to leak off and generate a filter cake. Dynamic fluid leakoff was taken through the upper and lower core at 1000 psi differential pressure for 90 minutes. A mixture of 2.26 oz (64 g) of proppant contained in 30 ml of gel was placed onto the cores with the generated filter cake. The simulated cleanup was run initially at 2 ml/min for 14 hrs using synthetic brine per the composition listed in Table 1. Conductivity measurements were made at regular intervals of 1, 2, 8 and 14 hrs. The simulated cleanup period continued by increasing flow rate to 10 ml/min for 2 hrs and finally 20 ml/min for up to 18 hrs or until the regained conductivity reached a plateau. Finally, a beta factor to wet nitrogen gas was determined.

Table 1 shows the classification of water type based on TDS concentration. Table 2 shows the levels of dissolved solids that will be tolerated by the fluid systems on offer. Table 3 shows a summary of the regained fracture flow performance results.

This new fracturing fluid formulated in 100% untreated produced water saved the use of almost 3 million gallons of fresh water during the completion of the two Bakken wells in the field trial.

## Success in North Dakota

As an example of the system's capabilities, fracture treatments were successfully pumped using untreated produced water containing > 300 000 ppm total



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**Table 5. Well analysis - flowback water**

Well type	Flowback water				
Anions	mg/l	meq/l	Cations	mg/l	meq/l
Chlorides	77856.20	2195.54	Sodium	30630.00	1332.41
Sulfate	532.80	11.08	Calcium	5067.00	253.35
Bicarbonates	158.60	2.60	Magnesium	499.00	41.07
Carbonates	0.00	0.00	Barium	3.84	0.06
Hydroxide	0.00	0.00	Strontium	348.40	7.95
Phosphate	0.00	0.00	Potassium	144.60	3.70
Silica	0.00		Iron	38.91	2.09
			Chromium	0.00	0.00
pH	6.00		Manganese	120.80	6.60

dissolved solids at 260 ° F (> 127 ° C) bottomhole temperature. This resulted in 11 million lbs (5 million kg) of 100 mesh and 20/40 mesh sand being placed over 26 stages.

The cost savings associated with TriFrac-MLT were proven by a job in North Dakota, US based on a total fracturing fluid volume of 45 700 bbls (7265 m<sup>3</sup>), the use of TriFrac-MLT led to a net price advantage.

The data in Tables 4 and 5 shows the reports on the water analysis for a typical flowback water sample both for produced and flowback water. Because of the high concentrations of the salts in the water, it was determined that the TriFrac-MLT system would be best suited.

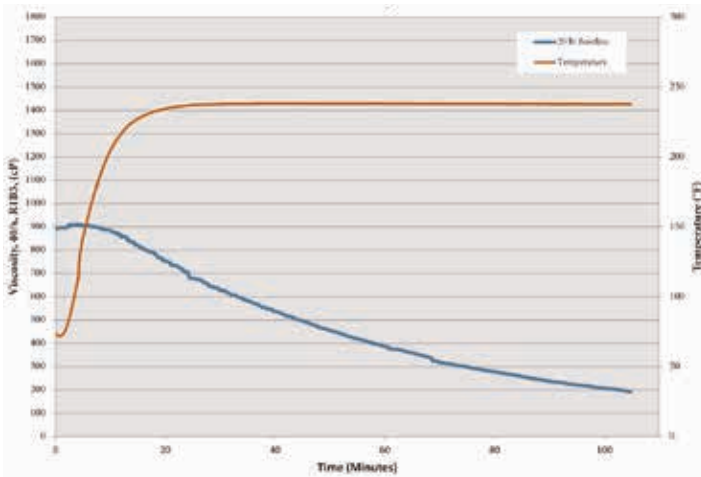
Shown in Figure 1 is the rheological profile for TriFrac MLT fluid system (for 20 lbs of polymer per 1000 gallons of water). Tests were run at 240 ° F (115 ° C).

### Summary

The company is focusing much of its research in finding new and better ways to address environmental concerns at all levels of its operations. With systems such as, TriFrac-MLT and Stratum-RW, operators are offered an option to conserve fresh water aquifers and reuse produced and flowback water. Trican has developed several other products that limit the strain on water resources, including Kronos™ (a high temperature ultra-low polymer crosslinked fluid with rapid break times), MVP Frac™ (a slick water system that is designed to enhance proppant distribution), and a line of salt tolerant friction reducers.

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**Figure 1.** 20 lb TriFrac-MLT breaker optimisation at 240 ° F.

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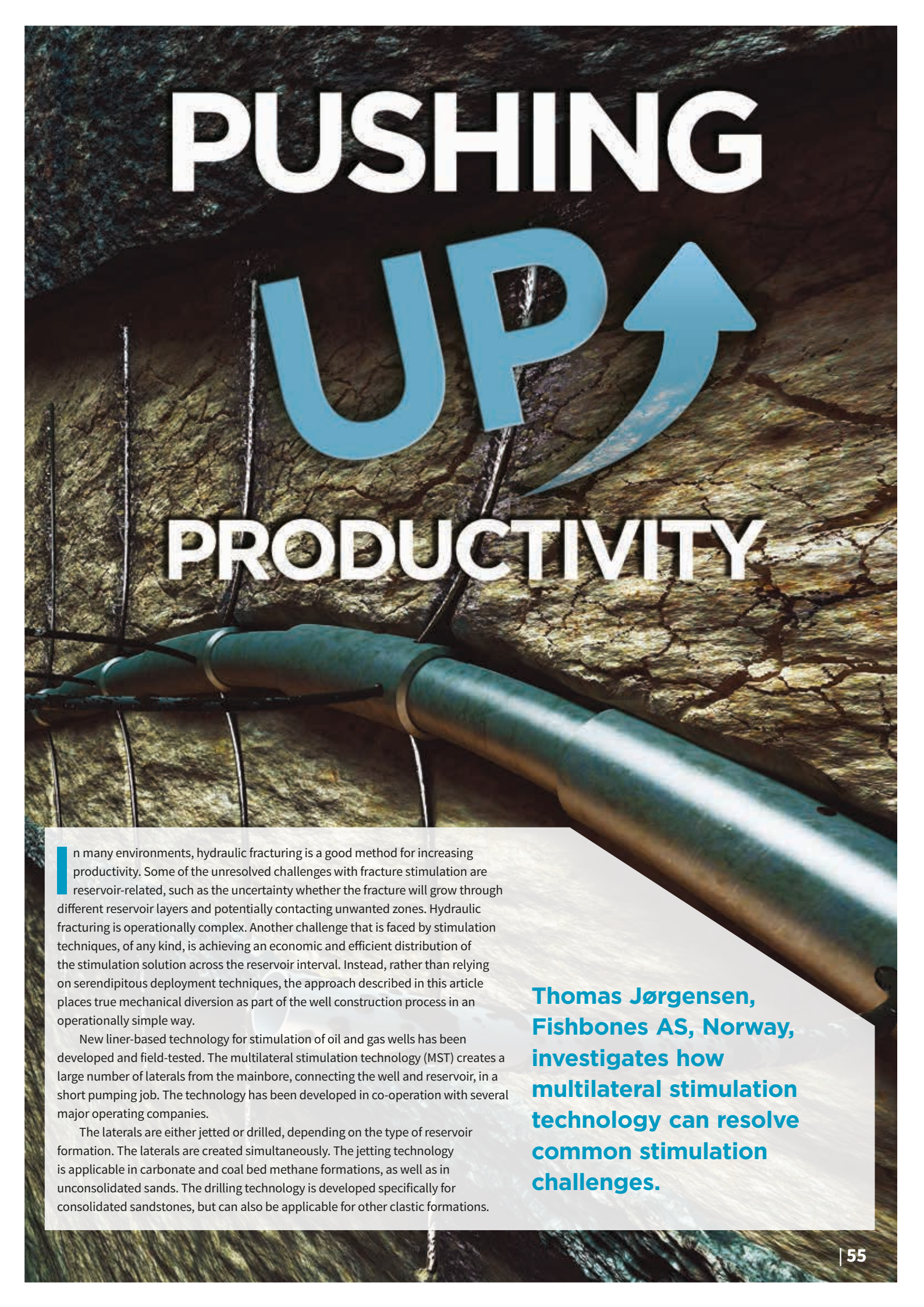
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# OILFIELD TECHNOLOGY





# PUSHING UP PRODUCTIVITY

In many environments, hydraulic fracturing is a good method for increasing productivity. Some of the unresolved challenges with fracture stimulation are reservoir-related, such as the uncertainty whether the fracture will grow through different reservoir layers and potentially contacting unwanted zones. Hydraulic fracturing is operationally complex. Another challenge that is faced by stimulation techniques, of any kind, is achieving an economic and efficient distribution of the stimulation solution across the reservoir interval. Instead, rather than relying on serendipitous deployment techniques, the approach described in this article places true mechanical diversion as part of the well construction process in an operationally simple way.

New liner-based technology for stimulation of oil and gas wells has been developed and field-tested. The multilateral stimulation technology (MST) creates a large number of laterals from the mainbore, connecting the well and reservoir, in a short pumping job. The technology has been developed in co-operation with several major operating companies.

The laterals are either jetted or drilled, depending on the type of reservoir formation. The laterals are created simultaneously. The jetting technology is applicable in carbonate and coal bed methane formations, as well as in unconsolidated sands. The drilling technology is developed specifically for consolidated sandstones, but can also be applicable for other clastic formations.

**Thomas Jørgensen,  
Fishbones AS, Norway,  
investigates how  
multilateral stimulation  
technology can resolve  
common stimulation  
challenges.**

The purpose of the technology is to increase well productivity, or injectivity in the case of injection wells, by better connecting the reservoir to the wellbore. The technology is applicable in low-permeability formations to create negative skin similar to the hydraulic fracturing process for reservoirs that are:

- ▶ Compartmentalised, layered, or naturally fractured.
- ▶ Without barriers to contain hydraulic fractures.

- ▶ Depleted where placement of hydraulic fractures is challenging.
- ▶ Without sufficient depth accuracy for sweet spot well placement.
- ▶ Located in areas where hydraulic fracturing is cost-prohibitive or impossible.

Damaged near-wellbore formation rock is bypassed. The length of the laterals is adjustable. This means that the depth of the stimulation is controllable. Thus, the risk of penetrating untargeted zones is eliminated.

### The technology

The jetting technology is comprised of a liner sub that houses four small-diameter, high-strength tubes called ‘needles’, each with a jet nozzle on the end. The sub is made up to a full-length casing joint and needle assemblies up to 40 ft long, are assembled in the workshop before being sent to the field. The subs are run as integral parts of the liner in the open hole and are positioned across the formation where stimulation is desired. The needles are located inside the sub/liner joints while the sub is run in hole. The liner is hung off with a standard liner hanger. In case of carbonate formation, a basic HCl fluid system is pumped. The fluids jet out of the nozzles, and the formation ahead of the tubes is jetted away by a combination of erosion and acid chemical dissolution. Differential pressure across the liner drives the needles into the formation, and they penetrate the rock until fully extended. All laterals are created simultaneously, resulting in a fishbone-style well completion with multiple laterals extending from the mainbore. This means 200 - 300 laterals in one well is achievable. The needles may be equipped with individual positive identification (PI) mechanism that shuts off the flow through the needles when they are fully extended, which results in increased surface pressure at constant pump rates.

The drilling version of the multilateral stimulation technology has been developed in a Joint Industry Project with Statoil, Lundin, ENI and Innovation Norway. The equipment configuration is similar to the jetting technology described above and the system is also deployed as part of the liner in the open hole, but each needle is equipped with a small drill bit instead of the jet nozzle. At TD, the liner hanger slips are set and the laterals are drilled independently and simultaneously. Drilling is powered by circulation of mud. Each needle has a turbine on the opposite end of the needle, located inside the liner. The turbines rotate and backpressure provides the required weight on bit to effectively drill the laterals. With this technique, no additional chemicals or pumping equipment is needed to stimulate the reservoir. The technology has been thoroughly lab and full-scale tested over the last two years and was recently fully qualified for deployment in a subsea dual-lateral well in the Norwegian Sea by a major Norwegian operator. The installation will take place in the second quarter of 2015. The well will target a tight sandstone formation overlaying a high permeable zone. The MST will enable the operator to increase productivity from the tight formation without the risk for stimulating into the higher perm layer, which would be detrimental to production from the target zones.

### Installations

The first deployment of MST took place in a vertical well in a coal bed methane application in South Sumatra, Indonesia, in November 2013. Two 7 in. MST subs were deployed across the main coal beds in the 8.5 in. open hole in accordance with the plan. Water was used as the jetting fluid, and full extension of needles was confirmed by pressure chart readings and subsequent milling operation prior to running a downhole pump for the dewatering phase. The initial flow rates from the well were good, exceeding the rates of a neighbouring well. The well, however, is not currently producing due to mechanical issues unrelated to the MST.

The first deployment in a carbonate reservoir took place in a tight limestone formation in the Austin Chalk in Texas, USA, in April 2014. The installation of the system was part of a pilot programme managed by the Joint Chalk Research (JCR) group, composed of BP, Shell, ConocoPhillips, the Danish North Sea Fund, Dong, Eni, Hess, Maersk, Statoil and Total.



Figure 1. Fishbones' Multilateral Stimulation Technology (MST).



Figure 2. Fishbones MST sub with needles and nozzles.

The pilot installation was also supported by the Norwegian Research Council.

The well, horizontally placed in a tight limestone formation with approximately 5% porosity at 10 000 ft TVD depth, was shut in after several years of production and prior stimulation and was considered to be without potential for normal re-stimulation. A 4.5 in. diameter lower completion string was planned for in the 6.5 in. diameter open hole. Fifteen MST subs with a total of 60 needles and three openhole anchors were spaced out with 4.5 in. diameter liner joints and run in the open hole. To land the completion, the string was rotated for 10 hours in accordance with the operator's standard practice. The pumping operation was completed after five hours, including jetting and fluid displacement. The creation of as many as 60 laterals in one well is believed to be a world record. The production results were very positive with an 8.3 times increase in IP-30 (cumulative production first 30 days), compared with well production before shut-in. The results confirm the significant stimulation of the well by the use of the multilateral stimulation technology.

A number of wells are being planned for MST installations worldwide, in both onshore and offshore locations.

### Reservoir simulations

Three-dimensional reservoir simulation studies of productivity have been made on various reservoirs worldwide using industry standard simulation models. Results show that an increase in incremental production by more than 500% over barefoot openhole completions is achievable with the MST, depending on several factors that include reservoir properties and the number of laterals.

A 'quick look' single well simulator has been developed and benchmarked with an established 3D simulator to simulate MST completed wells versus barefoot openhole completions. This model can simulate both producer and injector well scenarios, with or without injection/production support, and allows quick screening of wells and sensitivity analysis on critical reservoir parameters such as permeabilities and on optimum number of MST subs.

### Testing

It may be required to test whether a formation can be jetted or drilled with the MST as part of the well planning process. Testing is done on representative core samples supplied by operators. For jetting testing, a purpose built test unit has been developed for testing with acid at elevated temperatures and pressures. Testing with backpressure is needed to eliminate cavitation effects. Fluid volumes and penetration rates are logged and results can be extrapolated to estimate total required fluid volumes for multiple full 40 ft extension of laterals. This method was utilised for the first carbonate installation discussed above and the fluid volume estimation was within 8% of the actual volumes for full needle extension.

A test unit has also been developed to measure rate of penetration for the drilling technology.

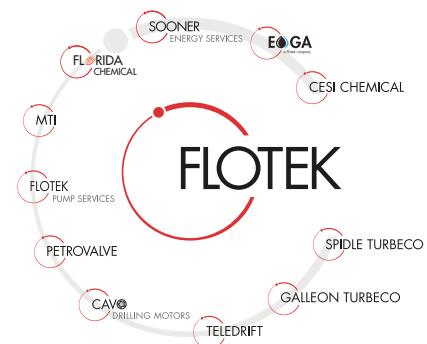
### Conclusion

New stimulation technology has been developed together with several major operating companies to overcome challenges with traditional stimulation methods, such as fracture propagation control, operational complexity and ineffective fluid diversion. Multilateral stimulation technology is a liner based stimulation system that creates a large number of laterals connecting the well and the reservoir in a short pumping operation. The laterals are either jetted or drilled, depending on the type of formation. The technology is field proven to significantly increase wells' productivity. ■

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# INCREASING DOWNHOLE INTELLIGENCE

**Chris Shannon,  
Fotech Solutions, UK,  
looks at how distributed  
acoustic sensing can aid  
in the boosting of oil  
and gas recovery rates.**

**A**s the oil and gas industry is faced with challenge of maximising recovery and production rates, it is increasingly looking to deploy more complex exploration and production techniques that benefit from having real time intelligence of well activity. This includes the adoption and deployment of the latest in sensing technologies to plan and monitor completion and production activities; technologies that will inform and accelerate decision-making across the value chain.

Because of this demand for greater downhole intelligence, oil majors and operators always stand to benefit from new technological breakthroughs. For example, in the 1990s, the key technology was distributed temperature sensing (DTS), starting in university laboratories but now commonplace worldwide. The breakthrough technology of this decade is distributed acoustic sensing (DAS). Furthermore, DAS itself is going through its own evolutionary cycle as a technology. The latest development sees providers deliver real time monitoring solutions that give users access to specific information, rather than delivering large volumes of data that will require subsequent analysis.

## Listening to visualise

When applied for downhole use, DAS systems work by converting a single optical fibre into the equivalent of tens of thousands of individual highly sensitive vibrational sensors. This optical fibre cable is run in the well, either in the casing or inside the production tubing, and runs alongside its entire length. The DAS system uses an advanced variant of optical time domain reflectometer (OTDR) instrumentation that monitors the coherent Rayleigh backscatter noise signature as pulsed light is sent into the fibre. The detection of the vibrations in this backscatter caused by acoustic disturbance at each point along the fibre enables engineers to 'visualise' and record what is going on downhole at every point of the well in real time. These acoustic

disturbances can be caused by everything from complications in a completion process to changes in flow dynamics.

This gives well engineers greater clarity than ever before. This enhanced visibility allows engineers to gain a far greater short- and long-term understanding of completion and production performance, and well integrity. This not only allows engineers to focus time and effort on value-adding activity, but can also be used to increase the success rate of operations and improve the efficiency and safety of exploration procedures.

Capable of recording all vibration activity occurring in-well during its deployment, DAS can be delivered in different ways to provide the maximum value to operators, with different processing techniques being applied to the data set to generate different operational benefits. However, there is an argument to suggest that engineers want real time information that can provide an overview of the critical incidents that are taking place during an operation, whilst being easily shared to increase access to live information across a company decision making team. To achieve this, DAS providers have focused on developing intuitive interfaces and data compression methods – making the systems far easier to interpret and use.

### Solving critical production issues

In terms of the general benefits of DAS, it is essentially solving two major issues for oil and gas engineers.

Firstly, operators want to see data in real time while downhole operations, such as hydraulic fracturing, are taking place. Hydraulic fracturing in particular is inherently difficult to monitor and the existing tools are extremely limited – completion engineers will often have no way of accurately knowing that a frack procedure has been successful across all zones, which can frequently be the case.



Figure 1. The Fotech Solutions Helios DAS unit.

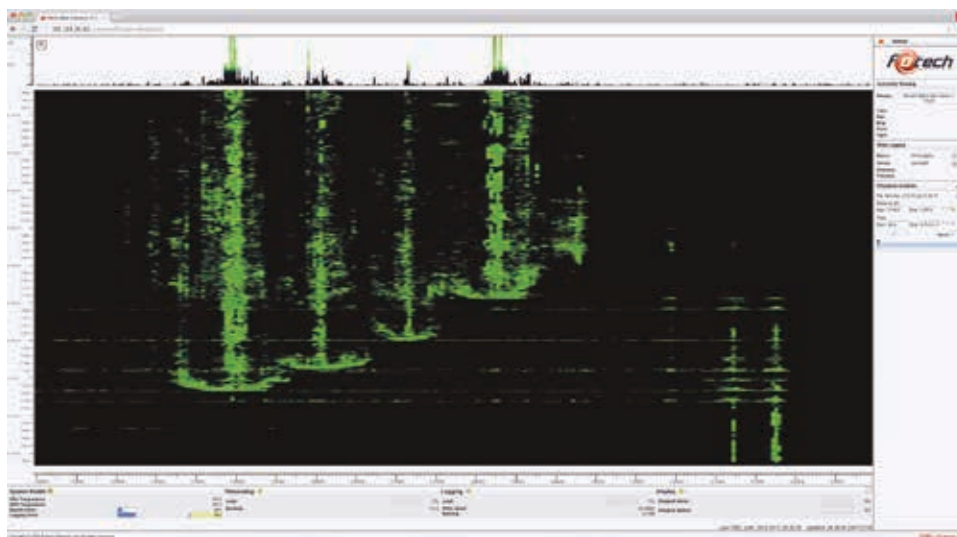


Figure 2. The live DAS interface recording acoustic data from a downhole operation.

DAS adds a new layer of intelligence in the monitoring of in-well activity. So, in the example of hydraulic fracturing, DAS can gather data to a level that gives engineers a real time log of the fracturing operation, providing an indication of fracture success in the exposed formation. Throughout any operation DAS is collecting and interpreting acoustic data to help build an understanding of the fracture operation itself, including events such as ball seating, gun firing and perforation. The DAS system can then help engineers gain visibility of the fracturing activity and propagation, including the sensing of fluid and proppant flow through the perforations. From this data, engineers can monitor the process and deliver increased confidence that the process is being carried out safely and efficiently, as well as establishing whether there are any downhole events that require further action.

The second key issue that DAS is addressing is that operators want to ensure that production at each well site is being maximised during a series of operations over a longer period of time. Analysing DAS data from a larger sample of operations can help engineers to ensure that the well is being stimulated efficiently and effectively, determine operational inefficiencies and assess what may need to be changed in future.

DAS is capable of being deployed on new wells and retrofitted on existing wells. This means that as well as the advantages in hydraulic fracturing DAS can also enhance a range of other downhole operations:

- ▶ Borehole seismic: Obtaining key data without well intervention or shut-in using fewer resources.
- ▶ Gas lift: Monitoring valve performance directly and in real time enabling optimum efficiency and planned maintenance.
- ▶ Flood front monitoring: Maximising recovery rates and optimising production.
- ▶ Downhole leak detection: Detecting leaks early and accurately to minimise disruption and cost.

With an optical fibre installed in the well, continuous long-term monitoring of a well's integrity after surface abandonment can also be achieved. By detecting distinct acoustic signatures DAS can visualise the accumulating energy from small leak events to generate a dynamic profile that increases the confidence in detecting a leak event so that the operator can be notified to take appropriate action. The process can be used to monitor for small leaks that can be easily missed by traditional abandonment procedures. As a result long term well monitoring is vital, especially with operators retaining liability for wells beyond abandonment.

In addition to the delivery of well information as a stand-alone sensor, DAS may also be correlated with other existing technologies, such as DTS to enable delivery of multi-dimensional, real time dynamic profiles of well conditions.

### Optimising DAS deployments

One of the key implementation challenges of DAS is in establishing effective and efficient data management tools. By adding a new layer of monitoring, DAS is also increasing the data needing to be processed and analysed in downhole operations. In other words the critical element of developing a DAS solution that adds maximum value to operators is not necessarily in collecting the information, but maximising the potential of the huge volume of data being produced in each individual operation.

Whether DAS is being used to analyse information in real time or over a longer timespan, operators are, at present, likely to be dealing with tens of terabytes of data for each individual monitoring period.

Considering that this data is collected from well sites, often in remote areas without access to high-speed broadband, it is often the logistical challenge around physical shipment of the data sets that restricts the ability to maximise the value of that data. Furthermore, sending huge packets of data to a different site via satellite connection is virtually impossible.

Currently the data collected from each operation has to be stored on physical hard drives and transported to locations where the sophisticated analysis can be carried out retrospectively on more powerful computers with the processing power to handle the reams of real time information. However, the data collected by DAS is extremely valuable for engineers looking to identify trends and potential anomalies that may show inefficiencies with a certain process.

Therefore, DAS providers are turning to new ways of optimising their solutions to provide the actionable information that engineers at the well site need and to maximise the potential usefulness of this big data. Having the ability to transport data across a network to conduct analysis in real time also increases the value of using DAS. As a result vendors are also optimising DAS systems to a point where data can be broadcast to different locations from the well site in near real time to enable data to be analysed by experts offsite as the operation happens.

To deliver these capabilities the data set must be reduced to a more manageable size, which is achieved through the application of data compression techniques. Combining a DAS system with advanced data compression software, delivers a solution where data is collected, interpreted and compressed to a manageable size, in near real time. For example, Fotech has partnered with Interpretive Software Products (ISP), a data modelling and interpretation software specialist, to enable compression of data into packets that are small enough (gigabytes, not terabytes) to be sent across a network from the site, without any loss of critical information.

By compressing data to a more manageable level, through the combination of DAS and sophisticated data compression tools, an

operator is able to deploy an increased suite of advanced data processing techniques and therefore enable far quicker delivery of in-well reports. The use of the data compression approach also means that transmitting information to operational platforms around the world in close to real time can be achieved at far lower bandwidths than would be possible otherwise. The ability to transmit data across a network as it is collected also opens up the possibility of genuinely global access to data from the well as it happens, allowing for distributed decision making by the key company stakeholders.

### Maximising efficiencies and minimising complexity

Ultimately DAS is providing data and interpretative tools that have simply not been possible until now. This increased intelligence gives the fibre-enabled well significant advantages. Used in conjunction with more traditional sensors, such as DTS and surface microseismic sensors, DAS creates a multi-dimensional, real time dynamic profile of well conditions. Combined with other existing technologies in this way DAS adds a powerful new element to the tools at the disposal of engineers, delivering valuable insight into both completion and production issues – affecting real time decision making, improving overall efficiencies and increasing safety.

What is important is that this new capability is not introduced at the cost of unnecessary complexity. As valuable as data is, in the real world application of any new technology like DAS there must be a higher premium placed on ensuring that the data can be easily understood. In the business of managing oil and gas operations it is the ability to quickly access and evaluate the critical information that is really vital to ensure that better decisions can be made efficiently in order that operational effectiveness is maximised.

By working closely together DAS vendors and well operators are ensuring that DAS systems are optimised to deliver the real time intelligence the oil and gas industry needs to maximise recovery and production around the world. ■

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# GETTING TO GRIPS WITH FIBREGLASS



**Joie Folkers,  
NOV Fiber Glass Systems,  
USA, shows how sustained  
oil and gas production  
can be achieved  
through the use of  
corrosion-resistant  
fibreglass pipe technology.**

The increasingly complex conditions in the oil and gas industry have created a quest for smarter tools and cutting-edge technologies to help operators maximise their production, avoid delays, save time and money while getting the highest rates of return. Today, one of the main tasks in the oil and gas industry is to effectively control corrosion and ensure oil and gas production sustainability. Corrosion problems have always presented a severe challenge to oil and gas operators because these problems are a real threat to production continuity and many times, result in frequent well shutdown and require costly maintenance and work over. Downhole production tubing, in particular necessitates high performance technology that is corrosion-resistant and cost-effective to allow a smooth flow of oil and gas.

Material degradation due to corrosion is a major concern impacting oil and gas production and can appear in a variety of forms such as leaks in tanks, casing, tubing and pipelines. The fact that most oil and gas

production includes co-produced water makes corrosion an even bigger challenge. Downhole tubing, surface pipelines, pressure vessels and storage tanks in oil and gas production are prone to corrosion by water, which is enhanced by the presence of CO<sub>2</sub> and H<sub>2</sub>S in the gas phase. Corrosion is a huge cost factor for oilfield operators. The total cost of corrosion in the US industries alone is estimated to be US\$1.372 billion annually, made up from US\$589 million for surface piping and facility costs, US\$463 million in downhole tubing expenses and US\$320 million in capital expenditures related to corrosion.

### Fiberglass pipe for corrosion challenges

The answer to the corrosion problem whether it is a chemical attack, microbially-induced, stray current, galvanic, sweet or sour gas or other types of corrosion, is the use of glass reinforced epoxy (GRE) piping, (a.k.a. fiberglass pipe). GRE is certainly not the only non-metallic material fabricated into piping components but when corrosion is linked with elevated fluid temperatures or pressures, the fiberglass reinforcement of the thermoset plastic resin certainly removes all



**Figure 1.** Fiberspar's spoolable feature reduces the number of connections during the installation.



**Figure 2.** Large diameter Red Thread HP installation.

marginality of performance from concern, unlike un-reinforced thermoplastic piping products (such as HDPE, PVC, etc.).

For over 60 years Fiber Glass Systems, a subsidiary of National Oilwell Varco, has successfully serviced the needs of the challenging oil and gas industry, helping its customers deliver maximum productivity. Throughout the years, by integrating innovation, expertise and tapping materials resources, the company has designed and engineered corrosion-resistant fiberglass piping systems.

To help increase the oil and gas production efficiency, the company has patented corrosion-resistant fiberglass products for pipeline and downhole applications. From a commercial standpoint, pipeline operators select fiberglass over steel because fiberglass eliminates corrosion problems, improves flow, is lightweight and reduces installation costs and time. Approximately 60% of pipeline failures can be accredited to corrosion and/or material/weld problems. The risk of a pipeline failure can be greatly reduced by selecting the correct GRE product that will eliminate both corrosion and welding problems.

Composite materials are becoming more and more common throughout the oil and gas industry and are being developed for many applications. Torque required for drill pipe is just too high for any fiberglass product available today. Fracking pressures are too high for practical use of fiberglass materials. These two examples, however, represent intense, intermittent loads being imposed. The focus for GRE applications is the long-term, continuously operating line pipe, tubing and casing applications, where corrosion elimination is of more value.

### Line pipe – opening up a new world of possibilities without compromising reliability

Fiberglass line pipe can be used for virtually every oilfield application, from production processing/flow lines to tank battery piping to WAG injection systems, and everything in-between.

In accordance with API specifications, Fiber Glass Systems' line pipe products are available in both low pressure and high-pressure designs. Corresponding API specifications are 15LR and 15HR. Also, the products are available in discrete joint lengths ('jointed') or in extended continuous lengths ('spoolable'). The jointed products include brand names such as Star™, Centron™, Red Thread HP™ and Bondstrand™ while Fiberspar™ is the spoolable product. Both jointed and spoolable products are available with pressure ratings up to 3500 psi.

Before looking at the applications of GRE line pipe, one needs to recognise corrosion's ugly stepbrother – erosion – as it applies to line pipe. Erosion occurs when material is removed from the pipe wall either due to shear stress from the flow itself or the impact and/or cutting action of solid particles in the flow as they pass by. When corrosion is taking place, the rust particles created are loosely attached to the surface and are easily and quickly removed. Subsequently, fresh substrate material is exposed to the corrosive flow and the cycle is repeated. In many cases, the establishment of the corrosion/erosion cycle is the most common cause of unpredicted corrosion failure. Quantification of the effects of the corrosion/erosion cycle is nearly impossible.

Line pipe is something oilfield operators want to forget about once they have it installed, typically buried. It is just supposed to work and provide an efficient fluid flow from one location to another, doing its job day after day. How does one increase the likelihood of this happening? A simple answer is to select line pipe made of the right material for the application, sized correctly for the flow, designed to take the pressure and temperature conditions and structured to hold up to any other loads that may be encountered. Fiber Glass Systems has developed an acoustic



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to help this process called the STAMP - Size, Temperature, Application, Media and Pressure. By sequentially considering each of these primary parameters, the range of available products can be 'filtered' to a lesser number of candidates where some of the individual features may be used for the final selection.

If the STAMP process is performed on a salt-water disposal system, at least 9 FGS products that would be candidates for use in a 3 in., 120 ° F, buried, saltwater, 1200 psi system could be identified. Some of these products would be 'over-kill' as they have much higher temperature ratings, so roughly three products remain viable. If the system is a single line going from a tank battery to a well 4000 ft away, the spoolable pipe would be the preferred choice as it would be installed very efficiently with connections made up only at each end. If the system is made up of multiple lines from several wells feeding into a main trunk line, the jointed products would allow for standard fittings to be placed at

intermediate locations for the tie-ins, allowing installation to proceed in a normal fashion. Since FGS can provide either product, the user does not have to be persuaded to use one type of product over the other but is counselled as to which better suits their needs.

Prior mention has been made to thermoset plastic resin and with regard to over-kill for temperature resistance. Typically, the epoxy resin used for line pipe is a general-purpose material. The properties of the resin system, comprised of the resin and a curing agent, are dependent on the curing agent. The components are mixed then heated after 'wetting' the glass fibres and undergo an irreversible exothermic chemical reaction to form a solid molecular 'matrix'. The curing agents utilised by Fiber Glass Systems include anhydride, aliphatic amine and aromatic amine. These systems are generally rated for oilfield use up to 150 ° F, 200 ° F or 212 ° F, respectively, with some variation (up or down) applied, if needed, for certain fluid streams. As expected, the cost for the higher performance material is higher, hence in the saltwater disposal example, the anhydride-cured epoxy products would have been the preferred and most economical choices. If a high-temperature production flow line, or a CO<sub>2</sub> injection line, had been under consideration, the aliphatic or aromatic amine products would have been selected.

An extremely important aspect of Fiberspar spoolable line pipe products needs to be made here. These products are true GRE composite products. The fibreglass reinforcing fibres are embedded in an epoxy matrix in the manufacturing process. This causes the fibres to perform in a manner physically superior to how they would if they were dry or loose and allows the product design to be licensed to API Specification 15HR. Also, very important is the bonding of this composite structure to the pipe liner through means of a 'tie-layer'. The resulting fully-bonded wall is unique to the industry.

Corrosion has another annoying relative – permeation. 'Permeate' is defined by Webster as 'to diffuse through or penetrate something'. In line pipe, it comes down to the fact that what is in the pipe will eventually end up within the pipe wall and potentially through the pipe wall, although in very minor often undetectable amounts. Permeation rates vary with the material of construction, fluid permeating, temperature and other operating conditions but they are never zero. This cannot be ignored in a responsible pipe design.

Spoolable pipe products typically have thermoplastic resin liners. Unlike thermoset resins described above, thermoplastic resins are individual, long chains of molecules that are not reacted together but are essentially 'tangled' into a solid form at a temperature below their melting point. If heated, they will liquefy and can be reshaped into another form, if desired, after cooling. This ability defines the temperature limit of the material for use as a structural member (such as an unreinforced pipe wall) and also points to a higher susceptibility to permeation for the thermoplastics. Since permeation occurs at the molecular level, unconnected molecules provide pathways to the diffusion. The spoolable pipe design must account for this. Reinforcing the liner with layers of steel reveals the familial connection of corrosion and permeation.

### Line pipe

One of many successful Red Thread HP line pipe installations was in Wyoming in 1987. Red Thread HP is an aromatic amine cured epoxy product that is capable of eliminating corrosion problems that are enhanced by CO<sub>2</sub> and H<sub>2</sub>S. The media in this application was saltwater with entrained oil and gas – 20 - 95% CO<sub>2</sub> with methane and H<sub>2</sub>S. Over 39 000 ft of 10 in., 12 in. and 16 in. Red Thread HP line pipe was installed. The operating temperature was 180 ° F with an operating pressure of 300 psig. The minimum burst requirement across the connection was 1350 psig. Lighter weight and ease of handling made the installation quick and easy.



Figure 3. Long-term corrosion protection with STAR GRE tubing.



Figure 4. Petroreconcavo downhole project using Centron GRE tubing.

## Downhole tubing

Corrosion does not start or stop at the wellhead. Whether handling corrosive production fluid or injecting corrosive saltwater, downhole corrosion poses significant problems. Some consider corrosion in tubing to be less of an issue than line pipe because tubing is accessible for inspection and repair. There is some logic to this but if tubing corrosion can be eliminated, the time, cost and lost production for ‘trips’ related to the tubing can be saved. The loading on tubing compared to line pipe is a good illustration of the versatility of GRE product design.

Fibreglass composites are approximately 20 times stronger and stiffer in the direction the fibres are aligned than they are perpendicular to this direction. This is defined as non-isotropic material properties and makes designing the products a bit more complicated. It is however overridden by the variations that can be accommodated by the material. Note: conversely, materials such as steel, which have the same physical properties in all directions, are identified as isotropic materials.

Line pipe analysis shows that the stress in the circumferential direction is approximately 2 times that in the longitudinal direction, (2:1 relationship). This assumes the pipe is unrestrained and has blanked-off connections on each end (such as during a hydrotest). However, downhole tubing would have a different stress distribution pattern due to the weight of the tubing as it is hung or tensioned within the well. Here, higher longitudinal forces are encountered that must be accounted for. What is the designer to do?

The classical design for line pipe is to align the fibres relative to the axis of the pipe at angles of  $\pm 54.74^\circ$ . This angle is the arctangent of the square root of 2 (stemming from the 2:1 stress ratio). Tubing loading varies from the top to the bottom of the well, but can be shown to allow the circumferential/longitudinal stress ratio to vary up to a 1:1 relationship (equal stress in both directions).

Using the same technique applied above for the line pipe, tubing can be made with the fibres oriented at  $\pm 45^\circ$ . This is the arctangent angle of the square root of 1. For shallow wells or wells where tubing is not in tension, such as in extraction of coal bed methane, this design is adequate. For deeper wells where higher tensile loads are needed, the product can be made with additional longitudinal glass added in the form of ‘weft’ fabric, a form of glass cloth where all the fibres are in one direction. A picture is provided.

Downhole tubing design must also consider external pressure since most wells have a static fluid level, which may be at the surface, in the annular space between the top and bottom. If the tubing goes on vacuum during operation, collapse must be avoided. This situation requires the designer to know the circumferential stiffness of the composite and use adequate thickness to provide the essential safety factor against collapse for the tubing string.

A unique use of GRE can also be seen in tubing liners, used by many companies, to gain the corrosion resistant benefits of fibreglass, supported by the strength and stiffness of steel. Thin, straight cylinders of composite are inserted into a steel tubing joint then grouted in place. Each manufacturer of these lined tubing joints has developed their own method of providing continuity of the liner through the tubing connections.

In 2011, Fiber Glass Systems took spoolable line pipe benefits downhole with the Fiberspar production system and a SmartPipe technology. SmartPipe combines Fiberspar spoolable pipe technology with integrated and easily removable power cables. Such a system is designed for downhole applications up to 6000 ft depth. This technology is

**Table 1. Pecos County case study**

Well data		Tubing data	
Location	Pecos County, Texas	Manufacturer	Fiber Glass Systems
Type of well	Produced water disposal well	Size	3 ½ in.
Tubing depth	11 483 ft (3486 m)	Resign system	Aliphatic amine
Static fluid level	1000 ft from surface	Pressure class	1500 psi (103.4 bar)
Packer	Baker Model F	Max. temperature	200 ° F
BHT	200 ° F	Construction type	Integral joint
Casing	5 ½ in. 17 #/ft	Connection type	3 ½ in. API 5B EUE 8rd ACT
Annular fill	Packer fluid		

aimed at artificial lift operations, mainly the rapid and simple deployment of electrical submersible pumps (ESPs).

### Star aliphatic amine downhole tubing

In the middle of 2009 in Pecos County in Texas, USA, a string of fibreglass tubing that had been in a saltwater disposal well was removed and replaced with a new string of fibreglass tubing. The new string of tubing was manufactured and supplied by Fiber Glass Systems.

The thing that stands out about this installation is the longevity of the fibreglass tubing under harsh conditions and the depth of the installation. The depth of the well was more than 11 000 ft. The fibreglass tubing that was removed had been installed and in service for more than 25 years. The condition of this tubing was almost as new. The information below gives details of the newly replaced tubing installation.

### Centron aromatic amine downhole tubing

Another example of a successful tubing installation is of Centron™ Aromatic Amine Downhole Tubing that took place in Brazil in 2012 as part of the Petroreconcavo project. The work started by collecting well data on the proposed application. The data was then used in the STARwell simulation program. The STARwell program is designed to help identify issues with the proposed application and select the best product to meet the needs of the project. Once the studies were completed, the products were delivered and two wells were successfully installed with 2 ¾ in. fibreglass tubing. A third well was successfully installed at the end of September 2012 and going forward the customer continues to install 19 additional wells.

### Downhole casing

Fibreglass casing is not extensively used, but the features of the material still fully apply. Casing is usually handled very aggressively, is run fast and is cemented in place. For conventional production, steel casing is typically preferred. Fibreglass casing is commonly used in sections, rather than complete strings for specific purposes such as electrical isolation, logging transparency, corrosion control and ‘kick-off’ points as the GRE material properties can be applied to the needs. Fibreglass casing can be perforated and is easily milled downhole.

Casing design is typically governed by collapse resistance considerations that would be encountered during the cementing operation. Once completed, there is little else for the casing to do other than to stay in place to allow well operations to occur unabated.

### Conclusion

Corrosion does not have to be a ‘given’ in oilfield operations. Multiple products have been designed for the full spectrum of applications in completion and production systems that eliminate corrosion. Proper design, selection and installation of these products will provide short and long term benefits in terms of lifecycle costs and continuous production. ■

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# INTEGRITY UNDER PRESSURE

**W**hether topside or subsea, offshore piping and pipeline integrity and the effective protection against threats such as corrosion or leaks is a high priority for oil and gas operators today.

Many of the world's fields today are brownfield – particularly in regions such as the North Sea, Middle East and Gulf of Mexico – where the focus is on maximising recovery from existing technologies. According to the World Energy Organisation, 70% of the world's oil and gas production comes from fields that are over 30 years old.

Many of these brownfields are characterised by ageing piping installations with an increased risk of corrosion and leaks and the need to carry out modification without jeopardising production rates.

There is also a need to reduce costs in such fields when it comes to ongoing maintenance and piping operations. While the recent North Sea report by Sir Ian Wood focused on the need for operators to maximise economic recovery from their fields and predicted a potential extra £200 billion for the UK recovery over

**Piping integrity is a small but central part of successful oil and gas operations. John Spain, Quickflange, UK, discusses some of the challenges.**



**Figure 1.** The Quickflange connection solution is designed in such a way that the flange can easily slide onto the pipe.



**Figure 2.** The connection solution is a modified weld neck flange with patented internal grooves.

the next 20 years, for example, it is clear that operational costs must be reduced in all areas including piping maintenance in order to achieve this.

In addition, piping repairs, construction, modification and tie-ins must often take place in brownfields around interdependent infrastructures where repairs on one platform or FPSO can have a significant impact on other areas within the production lifecycle.

Away from brownfield sites and the emergence of remote and frontier regions in areas such as offshore Brazil and Africa bring with them a different set of piping integrity challenges.

In the case of high pressure/high temperature (HP/HT) environments, piping challenges include the need to develop robust and effective maintenance processes and reliable connections, operate around existing infrastructure and reduce subsea intervention costs. A single subsea intervention can cost hundreds of thousands of dollars and in remote offshore locations, rig costs can be up to US\$1 million/d.

In summary, while piping integrity remains crucial to operators today, there remain a variety of challenges in delivering on such integrity. This applies to the subsea pipelines that transport hydrocarbons from onshore hubs to the complex network of piping on offshore platforms that, besides carrying oil and gas, support everything from fire fighting, cooling and water injection through to compression and the drainage of waste products.

So how are today's technologies addressing these piping integrity challenges?

### The technologies on offer

Look at the offshore piping integrity market today and there are a huge variety of technologies on offer – everything from corrosion control through to pigging, sand management and organisational-wide pipeline integrity management systems.

Yet, one of the crucial areas in piping integrity today remains connections and the attachment of piping to flanges. It is pipeline connectors that play a central role in areas such as permanent or

temporary pipe repair, the capping of redundant lines, tie-ins, other modifications and pipeline construction.

Today, however, there is a growing operator demand for piping connections to be flexible and able to take place around existing production operations; come with reduced costs and fast set up-times; and meet the latest safety standards. Yet, the most prominent technology for piping connections – welding – fails to meet many of these operator requirements.

Welding, for example, often necessitates production being shut down while the platform is in operation. The intrusive nature of welding also means that it is difficult to navigate around congested platforms or subsea equipment.

Welding also comes with significant logistical concerns requiring meticulous planning and the presence of highly skilled personnel as well as the dangers of delays in securing welding permits and mobilising personnel. This can lead to cost and availability issues meaning that welding can be an inappropriate option when dealing with short-term repairs and unplanned applications.

Finally, there are the safety implications due to the heat and flammability of welding operations. Welding requires access to gases, ignition sources and flames, meaning operators will need to regularly test for flammable gases, source adequate ventilation and isolate areas of operation.

Yet, it is not just welding that sometimes falls short. The subsea pipeline and mechanical connector market has also tended in the past to be characterised by high subsea intervention costs and complex and highly engineered solutions. This leads to the installation of subsea piping connections being a lengthy, cumbersome and often expensive process with significant support costs, diver training and availability issues.

### The emergence of cold-work solutions

With traditional hot-based welding presenting these limitations topside, more and more operators are opting for the alternative of cold-work solutions.

Cold-work solutions dispense completely with the ignition sources, flames and hot work associated with welding and instead deliver a leak-free mechanical and pressure-tight connection. Benefits include increased safety with no spark or heat generated during the activation process; no impact on production with cold-work activities taking place in a confined area; increased simplicity, speed and flexibility; and lower costs.

In its simplest form, the Quickflange topside cold-work connection solution is a modified weld neck flange with patented internal grooves machined in such a way that the flange can easily slide onto the pipe.

A simple hydraulic tool is then used to fit the flange onto the pipe through a process that flares the pipe into the Quickflange grooves. The assembled joint is stronger than the flange itself and is energised by the natural relaxation 'springback' of the deformed pipe material forced into the groove modification in the flanges. The two processes generate huge contact pressures, forming a seal and structural grip on the pipe.

The process is completed within minutes with the resulting connection qualified to be every bit as robust as a welded connection in terms of pressure retention and load resistance. Furthermore, the fact that the flange has no moving parts, grips or other components, ensures that less can go wrong.

The simplicity and flexibility of the system also requires little support equipment and is compatible with a variety of materials, such as carbon steels, stainless steel F316, 6Mo and monel, duplex, super duplex and copper nickel (CuNi).

### Going subsea

Some of the key elements of the topside Quickflange connection solution are also being seen subsea with the recent launch of the company's subsea pipeline repair solution.





**Figure 3.** *The connection solution works with multiple pipeline sizes and materials.*

The subsea version can be utilised in a number of subsea scenarios, such as pipelay; decommissioning; pipe work and new spool tie-ins; the replacement of existing flanges; subsea repairs such as for emergency spools; or for repair contingency purposes.

As well as the topside benefits already highlighted, there are a number of benefits specific to subsea operations. For example, as it is up to 60% shorter than other pipe-end connectors, the Quickflange Subsea is easier to handle with straightforward diver operations and no specialist diver training required. The activation tool can also be used on multiple pipe ranges with the installation being fully retrievable and reusable, thereby making it ideal for emergency repair and contingency repair systems.

It is these fast delivery times and easy implementation that can also reduce costs with a lowering of required diver time, and less pipe preparation, such as coating removal and deburial.

As of now, the Quickflange Subsea has been qualified to seal at pressures as high as 350 bar and is currently expanding from standard flange applications to custom-made connectors that can accommodate higher pressures and larger pipeline sizes of up to 12 in. This makes the solution increasingly suitable for critical subsea hydrocarbon applications.

### Case studies

The Quickflange cold-work solution and its impact on piping integrity is now being seen across the world – both topside and subsea.

For example, Quickflange recently carried out an installation in Brazil on an FPSO. The absence of hot work, speed of installation, avoidance of production shutdown and accessibility in tight areas were all key factors in the selection decisions – especially as the last production shut-down on the FPSO had resulted in losses of millions of dollars.

Two 3 in. Quickflanges were installed on the FPSO on a condensate scrubber line to replace a corroded section which had previously been repaired by wraps. The repair is permanent with the Quickflanges used to fabricate the repair spool and to attach tie-in points to the existing line, allowing a simple, localised spool repair to be completed. The activation time on the flanges took as little as 15 minutes each with the Quickflange installed by a trained Brazil-based technician.

Another example is a January 2012 deployment for ZADCO (Zakum Development Company), part of the ADNOC Group of companies, where Quickflange installed two of its solutions on an accommodation platform in the Upper Zakum field, one of the world's largest fields and now 40 years old.

In this case, the Quickflanges were installed on the discharge line of the fire water jockey pump on the accommodation platform. After successful hydro testing, the fabricated spools were sandblasted, painted and installed on the discharge line of the jockey pump to replace the existing corroded spool. The solution was found to significantly reduce the work scope offshore by the attending personnel.

There have also been a number of subsea orders since the launch of the Quickflange Subsea. One recent example was an order for four, 4 in. emergency pipeline repair system (EPRS) connectors for a leading Australian operator. The Australian operator ordered the complete subsea system including full hydraulics and pumps.

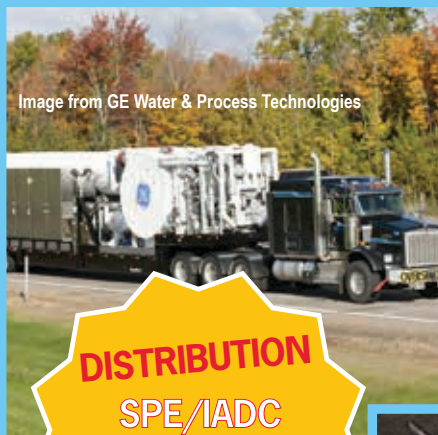
### Conclusion

New challenges to offshore piping integrity require new solutions. As operators face unprecedented challenges in guaranteeing the integrity of their offshore infrastructures and protecting production, the emergence of cold work solutions as an alternative to welding represents an important new development. ■

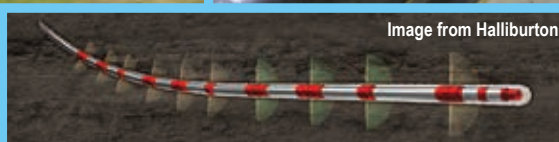
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February

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- **Advances in drilling**
- Flow control
- Coiled tubing
- Oilfield chemicals
- Water management
- Horizontal wells
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