

OILFIELD TECHNOLOGY

VOLUME 07 ISSUE 5-MAY 2014

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Alliance:
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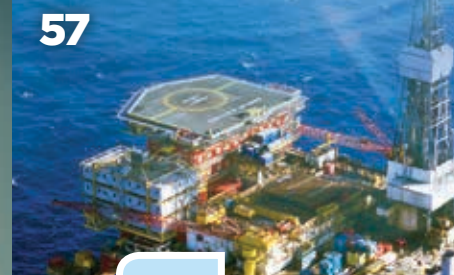
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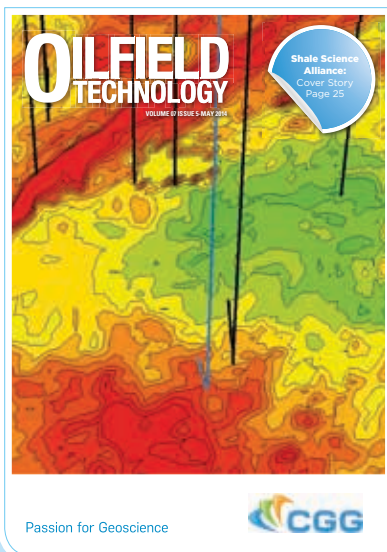
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An integrated geoscience workflow is used to highlight Haynesville Shale reservoir attributes between production wells. The CGG/Baker Hughes 'Shale Science Alliance' offers a number of differentiating geoscience technologies to meet the industry's need for a better understanding of unconventional plays. Cover image courtesy of CGG Data Library.



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Comment

May 2014



David Bizley, Assistant Editor
david.bizley@oilfieldtechnology.com

There is an old curse, often (apocryphally) attributed to the Chinese, which runs along the lines of “May you live in interesting times.” Times are certainly now ‘interesting’ for China as it begins to use its burgeoning power to work towards ensuring its energy security for the next century.

The nation’s efforts in this regard have seen it clash with neighbours over competing territorial claims in the South China Sea and, perhaps most notably, with Japan over the Senkaku (or Daiyou) islands. This increasing regional tension has drawn the attention of the United States and has been a not-insignificant factor behind America’s ‘strategic pivot’ towards Asia. In the meantime, China’s continued reliance on coal has been severely detrimental to the environment, with one Chinese scientist claiming that continued smog will have impacts similar to what would be experienced during a ‘nuclear winter’.¹ In short: China needs cleaner energy, quickly.

On the other side of the planet in Europe, home to the world’s largest economy (the European Union), the continent finds itself burdened by a politically inconvenient dependency on Russian gas. Being so dependent on a resurgent and (like China) increasingly assertive Russia has left the EU with few bargaining chips when it comes to negotiations with the Kremlin over issues such as Ukraine. With its economy now recovering, the EU’s demand for fuel is only going to rise and coal is, at present, the cheapest source available. Even Germany, figurative and literal ‘leader’ of the clean energy movement in Europe is beginning to turn down this route.² For a continental power that prides itself on cutting emissions, this is far from an ideal situation. In short: Europe needs cleaner energy, quickly.

So, what can be done to help solve the energy problems faced by both China and Europe? Thankfully the solution doesn’t lie in some as-yet-undiscovered future technology and the resources required are beneath our feet. If you’re a regular reader of *Oilfield Technology* then you’ll probably have already guessed what I’m talking about: shale gas.

Europe and China both sit on top of vast shale gas supplies, coming respectively to 470 and 1115 trillion ft³ of technically recoverable reserves, and the US boom could be (at least partially) replicated in these regions too, if the right conditions are allowed to flourish.

Not only would tapping this source of energy help reduce both regions’ dependence on imports and potentially reduce political tensions, but the increased use of natural gas (the cleanest fossil fuel) would go a long way towards meeting the environmental goals that both China and Europe have put in place.

China, seeing the necessity, has already begun the process of bringing its vast reserves online. Few expect the American success story to be emulated fully, but the Chinese government has set typically lofty targets of 6.5 billion m³/yr by 2015 and 100 billion m³/yr by 2020. Already two Chinese NOCs, Sinopec and its rival, PetroChina have announced a combined predicted output of 7.6 billion m³/yr by the end of 2015, putting the country well on track.

Europe, on the other hand, is lagging behind. Despite optimism from the industry and support from various governments, widespread (or at least well publicised) public opposition to hydraulic fracturing and outright bans on the process (as in France) coupled with hesitation over the initial costs of setting up operations in Europe has led to delays and concerns for potential investors.

Despite these concerns, shale gas will ultimately have an important role to play in Europe’s (and eventually the wider world’s) energy mix – economic necessity will see to it. Perhaps the best step forward for the oil and gas industry in the meantime is to continue educating and interacting with the public, debunking scare-stories and making it clear that responsible shale gas production can lead to a better, cleaner future. ■

1. ‘China’s toxic air pollution resembles nuclear winter, say scientists’ <http://www.theguardian.com/world/2014/feb/25/china-toxic-air-pollution-nuclear-winter-scientists>
2. ‘Rising Coal Use Clouds Europe’s Future’ <http://online.wsj.com/news/articles/SB10001424052702304450904579367074233771140>

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World news

May 2014

Statoil makes Barents Sea oil discovery at Drivis

Statoil has made a discovery believed to hold 42 - 54 million bbls of recoverable crude oil at the Drivis prospect in the Johan Castberg field in the Barents Sea.

Despite the good news of a discovery, the amount of recoverable oil was deemed to be somewhat disappointing; Statoil's Senior Vice President for Exploration on the Norwegian Continental Shelf said, "The exploration programme as a whole has not delivered on volume expectations."

The Drivis prospect was the last of five wells drilled across a one year campaign designed to boost the profitability of the Johan Castberg field – only two of the five wells struck oil.

Despite the lack of major discoveries so far, the field is still estimated to hold 400 - 600 million bbls of oil. ■

Shah Deniz contracts awarded by BP

BP has awarded US\$ 1.8 billion in contracts for the transport and installation of topsides and subsea infrastructure at Azerbaijan's Shah Deniz Stage 2 development.

The contracts have been awarded to a consortium of contractors comprised of: BOS Shelf, Saipem Contracting Netherlands and Star Gulf. In addition to the installation of jackets and topside units, the award is also believed to cover the laying of 360 km of subsea pipelines, the installation of diving support systems and upgrade work on three vessels.

BP President for the region, Gordon Birrell, was quoted as saying, "This is a huge contract award and it marks a major milestone for this historic project." BP had earlier awarded the consortium with contracts worth US\$ 750 million for the actual fabrication of the topsides.

At present, work is expected to be completed by the close of 2017, with first gas online by 2018. ■

Mexico's Pemex to sell 9.3% stake in Repsol

According to a recent announcement, Mexico's state oil and gas giant, Pemex is planning to sell a 9.3% stake in Repsol amid a downturn in relations between the two companies. According to analysts, the stake in Repsol is believed to be worth €2.3 billion at current market prices.

Pemex's relationship with Repsol has deteriorated in recent years, particularly after disagreements over Repsol's handling of the Argentine government's nationalisation of YPF.

The sale of the stake would come at a convenient time for Pemex as it seeks to raise money in advance of the Mexican energy sector being opened up to foreign investment later this year. The sale would also benefit Repsol by removing uncertainty over the sour relationship with Pemex. ■

Exxon Mobil earnings drop, but beat expectations

Exxon Mobil has revealed that its Q1 earnings fell by 4% to US\$ 2.10 per share, bringing the figure to US\$ 9.1 billion, a decline from last year's sum of US\$ 9.5 billion (US\$ 2.12 per share) for the same period.

Despite the drop, this outcome was still considerably higher than the profit of US\$ 1.88 per share that had been predicted by many analysts. Rex Tillerson, the supermajor's Chief Executive, was quoted as saying that the company's "first quarter earnings and cash flow reflect its continuing focus on delivering profitable growth and creating long-term shareholder value. Strong performance in the upstream benefited from improved production mix and increased unit profitability."

Upstream earnings actually rose by 11% (US\$ 746 million) to US\$ 7.8 billion for Q1. In addition, capital and exploration expenditures for this period were down by 28% to US\$ 8.4 billion. ■

In brief

Vietnam

Vietnam has clashed with China over the deployment of a Chinese oil rig in contested waters in the South China Sea.

According to one Vietnamese official, Chinese ships collided with Vietnamese naval vessels that were attempting to prevent the rig from setting up operations. No ammunition was fired and there were no injuries. The US criticised China's actions as "provocative and unhelpful". The Deputy Prime Minister of Vietnam, Pham Binh Minh, was quoted as saying, "Vietnam will take all suitable and necessary measures to safeguard its legitimate rights and interests."

Gabon

The Oil Minister of Gabon, Etienne Ngoubou, has announced that the country's oil production is expected to rise by 9% in 2014.

Ngoubou was quoted as saying, "Oil production in 2014 should reach 230 000 bpd or even 250 000 bpd". As far back as 1997 Gabon had been producing 370 000 bpd, but maturing fields have seen this figure decline over the last two decades. Gabon has long-term plans to boost production to 500 000 bpd with new offshore fields.

Austria

The Austrian government has revealed plans to increase royalty rates on its domestic oil and gas production in a move that should raise an additional US\$ 105.4 million in revenue.

One company to be hit by this change is OMV; the company's Chief Executive, Gerhard Roiss, stated that the change in the law had been revealed suddenly without prior warning being given to the sector.



World news **May 2014**

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- ▶ CEO of LR Senergy calls for action to tackle drilling skills crisis
- ▶ Oil and gas R&D spending to increase by 10% in 2015
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- ▶ China-Vietnam tensions high over drilling rig in disputed waters

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BG Group loses CEO and beats analyst estimates

BG Group has reported a fall in Q1 profits as lower production levels and increased costs eroded the impact of higher revenues. Total operating profits were down approximately 6%, bringing the figure to US\$ 2.01 billion.

BG Group recently announced the resignation of its Chief Executive, Chris Finlayson and warned that concerns over in Egypt meant that output for 2014 would be near the lower end of its guidance, but ongoing projects would see the company still meet its targets.

Andrew Gould, interim Executive Chairman, said: "In the first quarter, [BG Group] continued to make good progress with our key growth projects in Australia and Brazil. Group production volumes for the first quarter were consistent with our anticipated seasonal phasing, although production entitlement from Egypt was lower than expected as domestic offtake remains well above contractual commitments and reservoir performance deteriorates." ■

British Minister: shale to reduce reliance on Russia

British Minister of State for Business and Energy, Michael Fallon, has spoken out in favour of unlocking Europe's shale gas as a way to reduce the region's dependence on Russian imports.

The Minister was quoted by Reuters as saying, "There are a number of European countries that are extremely dependent on Russian gas [...] Europe has to reduce that dependence [...] to look at encouraging more diverse sources of supply of gas [...] and more generally to encourage indigenous sources of production of at least shale gas."

Several major companies (including: Total, GDF Suez) and other UK-focused operators have expressed an interest in taking part in potential UK shale gas operations. However, public opposition to shale gas (and the required legal changes) is still relatively widespread; one recent national survey found that 74% of UK adults were against a potential change to trespass laws designed to aid exploratory drilling. ■

Milestone in the Bakken as oilfields produce their billionth barrel of oil

The Bakken Field, spread across North Dakota and Montana has produced its billionth barrel of oil, according to data from IHS.

Jack Stark, Senior Vice President of Exploration for Continental Oil (a major operator in the Bakken) was quoted as saying, "This milestone validates the immense potential of the Bakken field and development is just beginning [...] Two-thirds of this oil was produced in the last three years. This is something our country can celebrate as the oil and natural gas industry continues to create jobs, grow our economy and secure America's energy future."

Ron Ness of the North Dakota Petroleum Council said, "There was very little Bakken crude oil production prior to 10 years ago then the Bakken oil technology really took off in eastern Montana, and North Dakota takes it to a new level."

Drilling in the Bakken in Montana first began in 2000 with operations in North Dakota beginning five years later; as of Q1 2014, the North Dakota side of the Bakken has produced 852 million bbls of crude oil, with the Montana side producing 151 million bbls.

The Bakken field covers some 25 000 square miles, with approximately two-thirds of this situated in western North Dakota. Unlocking the Bakken through the use of horizontal drilling and hydraulic fracturing has seen North Dakota's production levels rise to the point at which it is now the second largest producer in the US behind Texas. The state's daily production is currently on track to reach 1 million bpd this year. ■

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World news May 2014

Black Sea 3D seismic award for Dolphin Group

Dolphin Group has announced that it has been awarded a further contract for its *Polar Marquis* vessel to conduct a 3D seismic shoot across approximately 3000 km² of the Black Sea from the middle of May this year. The company's CEO, Atle Jacobsen, said: "Dolphin is on track delivering the second high-capacity 3D seismic vessel to the powerful Dolphin operated fleet in less than two months." Jacobsen also mentioned that the company's modern fleet was instrumental behind it securing these large scale seismic exploration contracts.

He added that *Polar Marquis* would make use of 14 seismic cables with a separation of 100 m and a length of 6000 m on its first survey. ■

After delays, Chevron starts shale drilling in Romania

According to an announcement from the company, Chevron has begun drilling for shale gas at an exploration site in eastern Romania.

Chevron originally won the right to look for shale gas in October 2013, but protests from residents saw the project delayed until December. Drilling has begun only recently after the completion of safety and performance checks.

A statement released by the company said, "Various measurements and rock samples will be taken to determine if natural gas is present and how it may be produced." According to some estimates, Romania could hold up to 51 trillion ft³ of shale gas and meet domestic demand for more than a century. ■

US\$ 552 million contract for Saipem on South Stream

Italian company Saipem has announced that it has been awarded a contract worth US\$ 552 million to work on the subsea section of the South Stream gas pipeline.

The offshore section of South Stream will consist of four parallel 931 km long gas pipelines, stretching across the Black Sea from Russia to Bulgaria and reaching depths of up to 2200 m.

Saipem's contract will see it cover additional supporting roles, such as engineering, the co-ordination of storage yards, cable crossing preparation and connecting the offshore section of South Stream to the land-based sections. The contract is set to be completed by the close of 2016. ■

Oil & Gas Exploration

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Exploring unknown acreage in the Norwegian Sea

This summer, the Norwegian Petroleum Directorate (NPD) will map the subsurface on the Mørerand High and Gjallar Ridge South in the Norwegian Sea, which is in the western part of the continental shelf. The objective is to acquire knowledge about unexplored acreage. The so-called 'shallow drilling' will reach up to 200 m down into the subsurface, to rocks that were formed about 55 - 65 million years ago in the geological Cretaceous and Paleocene periods.

"Geologically speaking, this is a blank spot on the map," says project manager Nils Rune Sandstå of the Norwegian Petroleum Directorate. "The objective of the drilling is to learn what kind of rocks can be found there, and how old they are."

"The drilling target on the Mørerand High is located near the area where the continental plates separate from the oceanic crust to the west. Material from this area is therefore scientifically interesting. It will also increase understanding of the Møre basin as exploration acreage for future petroleum activities," says Sandstå.

The NPD has previously acquired seismic in parts of the area, and has been granted NOK 55 million from the fiscal budget for this year's mapping. FULL VERSION 

New Zealand Oil & Gas increases exploration spending


New Zealand Oil & Gas (NZOG) is increasing its exploration spending as the company looks to find replacements for its Kupe and Tui oil and gas interests.

The Wellington-based company spent US\$ 25 million on exploration and evaluation in the three months ended 31 March 2014, according to its quarterly cash flow report.

Both the Tui oilfield and Kupe oil and gas fields situated off the Taranaki coast are in decline as the company looks for alternative sites.

The Pateke exploration well, which falls in the Tui permit zone, is thought to contain 2.5 million bbls of oil, the company said. If Pateke production went ahead it would "bolster output rather than change the end date" of the Tui field, explained Andrew Knight, CEO.

"It has oil in it which appears to have the same characteristics as discoveries nearby elsewhere in the Tui permit and we are cautiously optimistic it will get to the point where we complete drilling [and] we will be able to develop it," Knight added.

NZOG has a 27.5% stake in the Tui field and a 15% interest in the Kupe field. FULL VERSION 



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A close-up, high-angle shot of industrial machinery, likely a welding or cutting process. Two large, dark metal components are positioned vertically, with a bright, glowing point of contact between them. A dense spray of bright orange and yellow sparks erupts from the point of contact, cascading downwards and outwards. The background is dark, with a grid of circular holes visible on a metal surface above the machinery. The overall lighting is dramatic, with strong highlights from the sparks and machinery.

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An aerial night photograph of a city, likely Los Angeles, showing a complex highway interchange with light trails from traffic. In the foreground, a large, modern building with a curved facade is illuminated. The city lights extend into the distance under a dark blue sky.

A LEVIATHAN PROBLEM

Dirk Frame, T.A. Cook Consultants, Germany, examines the challenges that face the development of the upstream oil and gas industry in the eastern Mediterranean.

Economic advancement, population growth and with it, a sudden increase in energy demand mean that recent offshore natural gas developments in the eastern Mediterranean could engineer a power shift in the region, ultimately resulting in a new Eastern Mediterranean Energy Corridor.

However, continuing political tensions between the key players pose a serious threat to the success and even the very existence of regional upstream projects.

This article will examine the recent offshore natural gas discoveries in the region, with particular focus on Cyprus, Turkey and Israel to explore how energy infrastructure is the focal point upon which the entire success of upstream development in the region pivots.

Recent discoveries

In 2009, Texas-based Noble Energy announced the discovery of 250 billion m³ of gas in offshore Israel: the Tamar field. Shortly afterwards, Noble then announced the discovery of the Leviathan field (worth 476 billion m³) in offshore Israel, as well as the Aphrodite field, which lies in offshore Cyprus. These findings were then supported by the United States Geological Society: in 2010 it published a report on the Levant Basin, which lies underneath Syria, Lebanon, Israel, Jordan, Palestine and the waters between those countries and around Cyprus and Turkey.

The report concluded that a total of 1.7 billion bbls of undiscovered oil and 122 trillion ft³ of undiscovered gas resources lay in the basin as a whole, adding a whole new angle to the investment interest in the area.





Figure 1. Location of Aphrodite and Leviathan fields within the Eastern Mediterranean maritime borders.

According to a report by the US Energy Information Administration (EIA), those discoveries “could meet current regional demand almost indefinitely.”

The fact that Israel alone consumed 90.5 billion ft³ of gas in 2011 but only produced 87.5 billion ft³, thus forcing the country to import energy from its neighbours, means that both the financial and economic value of these discoveries is significant.

Leviathan politics

While Israel has traditionally filled the gap between oil supply and demand via imports, its gas needs had been accounted for by the El Arish-Ashkelon Pipeline running between Israel and Egypt, and owned and operated by the East Mediterranean Gas Company (EMG). However, following the 25 January revolution in Egypt in 2011, many Egyptians called for the ending of gas exports to Israel, some even accusing it of breaching its obligations and of having stopped payments a few months prior. In 2012, gas supplies to Israel were unilaterally halted, representing a new low in political relations between the countries.

As Israel has begun to receive supplies from its Tamar and Mari-B fields since the beginning of 2013, it no longer needs the El Arish-Ashkelon Pipeline. Indeed, according to current forecasts the Leviathan and Tamar fields together can meet Israel's domestic needs for up to 25 years and may transform the country into a net exporter of gas. As Tamar is considered to be able to fulfil Israel's domestic requirements alone, it is likely that Leviathan outputs will be pushed towards export.

However, two obstacles currently hamper such a golden future for Israel. Firstly, the fact that the Leviathan spoils lie beneath more than 5000 ft of water means that significant investment will be required in order to remove the oil and gas that lies there safely and profitably. That investment not only depends on the security of the region, but also on the clarity of Israeli policy towards exports.

Currently, the ownership of the Leviathan field is split between Texas-based Noble Energy, Israel's Delek Drilling and Avner Oil Exploration, Ratio Oil Exploration and Australia's Woodside Petroleum Limited, to whom the partners sold a stake earlier this February. However, following the US\$ 2.3 billion investment from Woodside, some uncertainty has prevailed over the future of the project, due largely to the reluctance of the Israeli government to clarify exactly how much of the recoverable resources they will allow the partners to export. In an analyst conference presentation

given on 17 December, 2013, Noble stated that the figure stood at 40% of the total, but the delays had already caused the company to postpone their production start-date for a year to Q4, 2017.

A new energy axis

The resulting drop in partners' share prices that followed has no doubt caused some to carefully consider their investment, while further disputes with Lebanon over a maritime border between the two countries could lead to further instability. The risk that ongoing troubles in Syria could spill over into Lebanon exists and contributes strongly to the pressing need to find a way of transporting oil and gas from these fields safely to Europe. As the extension of the Arab Gas Pipeline through Syria to Turkey is unlikely to happen in the near future and taking into account the unrest in Egypt, not to mention the number of jihadist attacks on the pipeline in Sinai over recent years, another way of connecting the fields in the eastern Mediterranean sea to Europe is urgently needed.

This is where Cyprus, Greece and Turkey come into the picture. Noble, again a key player in the region, gained the exploration rights of Block 12 in Cyprus' Exclusive Economic Zone (EEZ) in 2008, where it then went on to discover the Aphrodite field. Following its finds there, Total of France went on to pay Cyprus €24 million for the license to explore Blocks 10 and 11, while Italy's ENI and South Korea's KoreaGas Corp. (Kogas) gained access to Blocks 2, 3 and 9. Production is not expected to start until 2018 for domestic use and 2019 for export, but that still leaves little time for the transport problem to be solved.

The first and most cost-friendly option would be to build a pipeline to Turkey in order to feed into existing infrastructure there, but Turkey claims the waters in which Aphrodite lies as its own and therefore rejects the Cypriot claim to it. Cypriots worry that even if an agreement could be reached with Turkey as to ownership and use, Turkey would use it as a political tool against them.

As a result, in November 2012 Cyprus, Greece and Israel agreed to set-up an Eastern Mediterranean Energy Corridor, which would connect gas from offshore fields in Israel and Cyprus to a liquefying plant at Vassilikos, Cyprus and to ship it on from there to Greece. This project contains a number of advantages: firstly, Leviathan and Aphrodite are only 34 km apart from each other, meaning connecting their supplies would not be too difficult; and secondly, it conveniently bypasses Turkey. Additionally, some domestic resistance in Israel against building LNG plants at Ashdod, Ashkelon and Eilat mean that building the plant at Vassilikos Cyprus handily gives Israel access to the EU without too many problems on home soil.

There are however, some drawbacks to this project. The cost of building the LNG plant at Vassilikos is estimated at US\$ 6 billion, which Noble, Delek, Avner and the Cypriot government will share in parts, perhaps supported by ENI, Kogas and Total at some point in the future. The area at Vassilikos is, though, only approximately 2 km² and some question whether it will be able to support the level of exports the investors plan. For Israel, there is some concern as to how to control export revenues, which as mentioned above, is a key issue for the Israeli government. Equally, should Cyprus become further entangled in deeper political tensions with Turkey, the security of the plant and the whole project could be jeopardised.

Perhaps the most appealing option of all, until tensions in the area relax is a floating liquefied natural gas (FLNG) installation. The Tamar FLNG project, which attempts to draw on volumes from the Tamar field is estimated to cost around US\$ 5 billion, but would allow the export of almost 144 billion ft³ per year.

The skills required not only to make such projects materialise but to function safely and profitably demand a high level of staff expertise and advance planning though, which can sometimes mean huge cultural barriers need to be overcome. Operating in an area riddled with political and religious dispute and occupied by military forces, which are

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sometimes hostile towards one another makes employee safety perhaps the most important issue. This factor alone will likely deter the influx of skills from abroad, adding handsomely to the cost of employment and employee protection. Where skilled workers can be recruited locally, the probability that deep cultural tensions would exist between them is high and could require some nifty managerial footwork to keep operational peace.

Furthermore, the inherently dangerous nature of working offshore with resources that lie so deep means that particularly stringent safety operations and transport logistics processes must be put in place. External factors such as wind speed, direction and currents must also be taken into account, while traffic concentration and helicopter or boat utilisation will need to be regularly scrutinised. If space is limited, poor platform and deck space organisation can further add to costs: operators will need to be extremely vigilant if blocks are to be made – and kept – profitable.

Worldwide influence

Taking into all of these aspects into account, it is likely to take some time before any of the fields connect with EU soil. The EU has a vested interest in the development of the Eastern Mediterranean Energy Corridor due to its current dependence on the Russian Federation, Norway and Algeria for gas. Obviously, the Russian Federation is keen to remain prominent in the area and has so far been the largest foreign direct investor in Cyprus, bailing out the island's banking sector at the end of December 2011. It has also been actively collaborating with Israel, with whom it signed an initial agreement to export LNG from Tamar early last year.

The entire issue as well as all of the projects associated with these discoveries depends fundamentally on the growth of demand for gas in the EU and the willingness of Israel to co-operate in terms of exports. While some predict gas demand to continue to increase steadily after a sudden decrease following the financial crisis, the EIA expects demand growth

to slow to levels seen before the recession. If the latter scenario occurs, then the viability of any of the projects outlined above will be crucially undermined.

Equally, if Israel decides to change its policy towards the amount of gas that it allows to be exported, the return could prove to be too low for key investors, without whom the fields will remain untapped for an indefinite period of time. Even if policy remains stable, the delays that Leviathan has already suffered are estimated to be costing the country almost US\$ 1 billion a month in savings, according to estimates from Mr. Silvan Shalom, Minister of Energy and Water Resources in Israel.

Wider impact

Regardless of the above speculations as to what form the Eastern Mediterranean Energy Corridor may take, the fact that energy majors such as ENI and Total are willing to invest such large sums means that the risk is likely, at least in their eyes, to be worth taking. As long as the key players can find a way to work together without becoming embroiled in the many and varying regional conflicts in the area, the corridor could provide a way for Cyprus and Greece to climb out of debt and for Israel to take on a new role as energy supplier. That in itself could have a major impact not only on relations between Israel and its neighbouring countries, but also on the wider energy market.

Dependence on Norwegian imports and the impending vote in September as to Scottish independence from the United Kingdom (implicating the natural reserves of the North Sea at the same time) could all lead the EU to lean favourably towards supporting growth in the eastern Mediterranean. That so many factors affect the development of the Levantine fields and that their development in turn has such wide-reaching effects – both politically and economically – makes it an unusually unique case. Whether it actually materialises though remains dependent on the ability of all parties to work together: a Leviathan task. ■

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HIGH CHANNEL COUNT ACQUISITION IN CHINA

Binu Joy, INOVA, USA, shows us how the use of advanced seismic technologies and efficient methodologies can boost productivity and help lower operational costs.

In many regions of the world, the majority of geophysical service providers continue to use cable-based acquisition technologies for conducting the simplest 2D to the largest, most complex 3D surveys. Crews have equipped themselves with the most advanced cable-based systems on the market to take advantage of their superior reliability and accuracy in providing real time data acquisition. As the seismic industry demands higher quality data at lower operational costs, acquiring high-density sampling with high productivity vibroseis (HPVS) is becoming more favourable. However, these projects introduce extreme challenges

in managing equipment, personnel, logistics and achieving desired productivity levels. BGP, the world's largest land seismic contractor, provides data acquisition services of the highest quality by utilising advanced seismic technologies such as INOVA's G3i system combined with the most efficient methodologies in field operations.

BGP has been exploring the Xinjiang Province of northwestern China for several years. The 150 000 km² (58 000 sq. mile) area is hydrocarbon rich and is the fourth largest onshore production area in China with an estimated 8.7 billion t (63.7 billion bbls) of

oil reserves. In 2013, the Xinjiang Oilfield Company, a subsidiary of PetroChina Company Limited and China National Petroleum Corporation (CNPC), awarded BGP a 3D project to explore 388 km² (150 sq. miles) of the Junggar Basin located in northern Xinjiang. BGP's client wanted to image targets down to approximately 4 km (2.5 miles) in depth to locate reservoirs and distinguish fault displacements. Seismic data from a prior 2D acquisition survey in this area was insufficient and the need for high fold, high resolution data became more apparent. Coupled with stringent design requirements and a tight schedule, BGP decided to perform this survey using more than 63 000 channels with a 52 000 live channel patch and distance separated simultaneous slip-sweep (DS4) operations. Widely accepted in the seismic industry, HPVS operations leverage multiple vibrators and sophisticated sweep techniques to obtain greater productivity than traditional



Figure 1. BGP performed DS4 operations with multiple vibrators to obtain greater productivity than traditional source methodologies.

source methodologies. Therefore, the company needed a high capacity acquisition system to support large-channel counts, continuous recording and source-driven operations. In their 60 years of service, this project was the company's first attempt to acquire seismic data using channel counts of this magnitude. Consequentially, it would become one of their most challenging projects as well, requiring extreme equipment management and logistical co-ordination.

Selecting the right technology

BGP selected INOVA's G3i recording system since it supports over 100 000 channels with its advanced field electronics and state-of-the-art centrals. Crews have successfully deployed almost 200 000 channels of G3i in challenging terrains and under extreme temperature conditions around the world. BGP has operated the system on numerous surveys and has become efficient in utilising the system. Having gained valuable experience from completing smaller-scale projects, the company had confidence in its abilities and G3i's field performance. The G3i cable-based system demonstrates ruggedness, reliability and flexibility. Constructed of aircraft grade aluminium, its enclosures protect the electronics from damage during constant field transport and deployment handling. Furthermore, the system's box-cable-box architecture, low power consumption and intuitive software tools allow G3i to be well suited for seismic super-crews.

BGP's partnership with INOVA enables access to the latest seismic technologies. Both companies understood the importance of this project and the challenges that lay ahead. And so in preparing for this survey, BGP purchased high-performance central computers and several thousand additional G3i channels to supplement their existing inventory. INOVA would also supply field service teams onsite to offer technical support if needed and ensure the system operated without interruptions. Once the survey design was finalised, properly trained personnel became available, and adequate quantities of equipment were on hand, BGP mobilised its seismic crew to begin operations in early October.

The oilfield's landscape is composed mostly of desert gravel plains surrounded by small hills and gullies. The vast open land provided the crew with great latitudes of freedom for conducting high productivity vibroseis operations without obstructions from natural or cultural structures. To put its size in perspective, the project area of 388 km² is larger than some North American cities. This high-density, wide azimuth survey required more than 63 000 channels, 15 000 receiver line cables, 60 000 analogue geophone strings, 20 vibrators and numerous support vehicles. BGP's seismic crew deployed the equipment and completed sweep tests within three weeks. Even as temperatures crept down to -10 °C (14 °F), the determined crew continued to operate efficiently in the cold weather. They laid out nearly

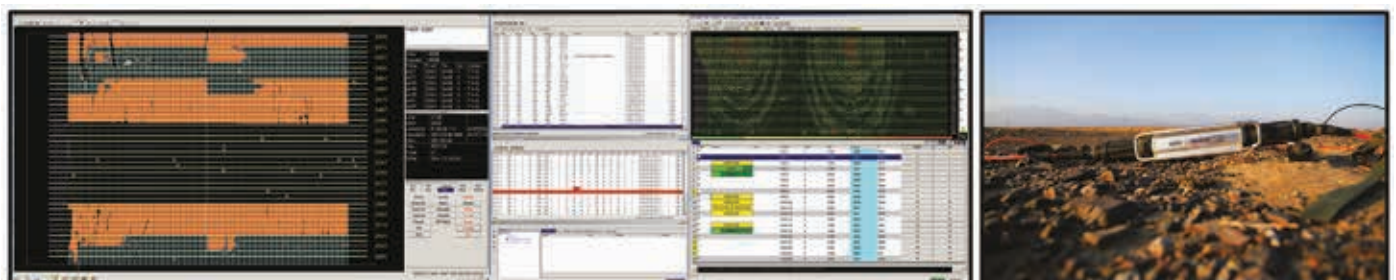
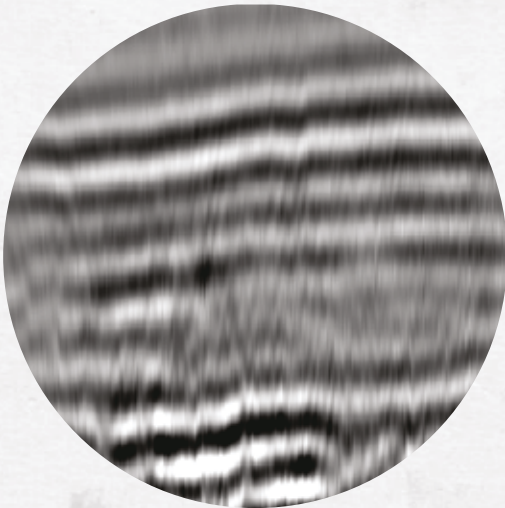


Figure 2. G3i's software tools allowed crews to monitor real time data during seismic operations.

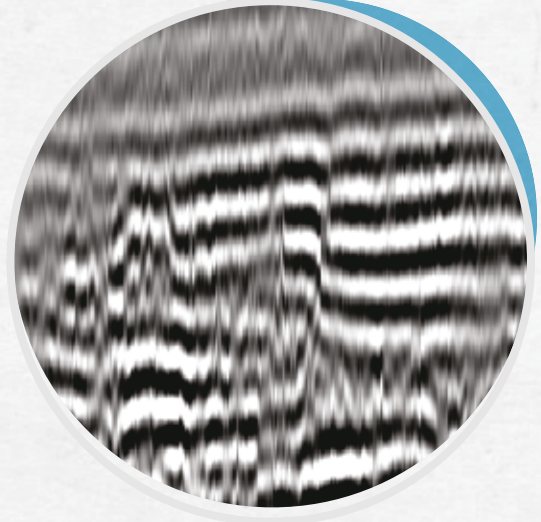
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Figure 3. The 3D project area spanned nearly 388 km² within the hydrocarbon rich Xinjiang Province of northwestern China.



Figure 4. BGP utilised small recording trucks to house G3i's central and QC station computers.

3300 km (2100 miles) of copper receiver line cables and if one were to connect them together, it would create a communications pipeline from Calgary, Canada to Houston, Texas.

The super-patch of 52 000 live channels encompassed approximately 192 km² (75 sq. miles). Its design parameters included 39 receiver lines spaced 150 m apart with 25 m receiver intervals. Each geophone array of 10 analogue phones had a 9 m x 9 m octagonal arrangement. The system would record seismic data continuously at two-millisecond sample intervals. With the fast pace of shooting, the equipment would record almost 500 million traces per day. To meet the extreme data management challenge, BGP used INOVA's new PCI Express-based seismic processing module (SPM) which is designed to handle data for up to 100 000 channels. A secondary computer, quality control module (QCM), was also set up in the recording truck to perform real time data QC and transfer data to removable hard drive modules. When faced with an unprecedented magnitude of incoming data from the field

stations, the QCM can easily help crews maintain high levels of productivity.

Source operations took place 24 hours a day with 20 vibrators performing DS4 operations. The crew operated multiple vibe clusters, separated at distances of 14 km (8.7 miles), with dynamic fleet grouping to obtain higher productivity levels than conventional sweep techniques. The communications hardware and messaging protocols implemented within the products are essential for large-scale DS4 operations. Each vibrator was equipped with INOVA's Vib Pro™ source controller and Connex™ Vib system. Vib Pro enabled the operator to have better force control, reduce harmonic distortions and carry out source-driven acquisition. The Vib Pro encoder/decoder units allowed the crew to maintain efficient operations even with separation distances of up to 14 km (8.7 miles). BGP required a single radio frequency to establish proper communications for source control. The user-friendly Connex Vib system provided navigation and positioning of vibrators. This standalone system accurately recorded GPS co-ordinates, sweep start times, post sweep (PSS) attributes and VSS ground force measurements. Source parameters included sweep times of 16 seconds and slip times between 9 and 11 seconds with a broadband frequency range of 3 Hz to 90 Hz. Source generation regularly exceeded 10 000 vibration points per day, totalling 290 772 source points while maintaining a PSS return rate of over 99%. In order to keep pace with the aggressive shooting schedule, the well-trained crew was rolling 5000 to 6000 channels per day. BGP was able to execute this immense acquisition operation with a combination of 675 personnel and advanced seismic technology.

Representatives from several international E&P companies were invited to witness first-hand the system's performance and reliability in recording high-quality data. The visitors were interested in observing how production levels on such a massive project were maximised, and they were excited to see the seismic acquisition technology in action. Inside the small recording truck, BGP geophysicists and other observers monitored real time data during source operations using sophisticated software tools. The SPM central separated and correlated the two active patches within the super-patch during DS4 while handling multiple overlapping shots without computing delays. The system captured an average of six terabytes of data a day, which the operators off-loaded to removable hard drive modules for processing. As expected, the G3i system functioned according to its specifications and presented no issues in recording data throughout the spread.

Summary

This 3D survey was the largest channel count project in China and the third largest in the world to date. The attendees from the E&P companies, BGP management and Xinjiang Oilfield Company were impressed with the system's recording capabilities and the crew's efficiency in quickly deploying equipment and conducting HPVS operations. The survey was successfully completed within six weeks and its results exceeded expectations in terms of crew management and equipment utilisation. The Xinjiang Oilfield Company was so pleased with the project's data quality and its high operational productivity that they scheduled another large-scale seismic survey of similar size in the Junggar Basin. ■

Note

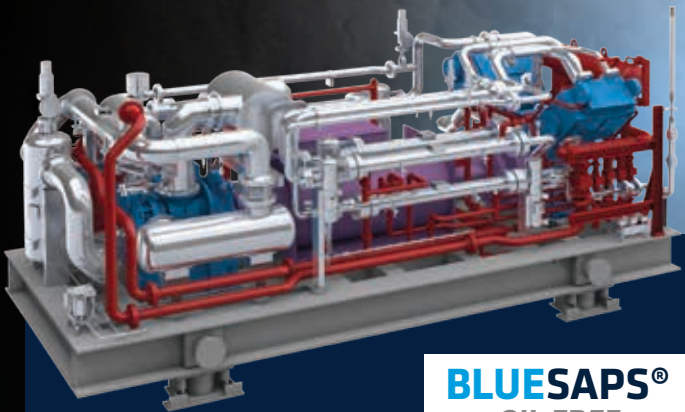
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UP UP & AWAY

Oilfield Technology correspondent Gordon Cope reveals the intriguing technological surprises that upstream oil and gas has in store.

Much has been made, with great justification, of the technological advances in horizontal drilling and hydraulic fracturing that have revolutionised the oil and gas sector in recent years. But there is a host of new technologies currently arriving, sitting on the horizon (and hovering just over it), that have the opportunity to enhance the industry even more.

Marc Godin is a technical contractor for the oil and gas industry, with 30 years' experience in technology development, R&D and collaborations. "The industry looks to technology to improve production, increase efficiency, reduce environmental impact and improve worker safety," he notes. "You can do

something simple, like converting rigs to burn natural gas to save costs and reduce greenhouse gases. But we are also hearing about new uses for satellites, unmanned aerial vehicles, robots and micro-sensors; there is huge potential."

Planning

In order to be profitable, modern unconventional resource plays (i.e., tight shale formations with abundant oil and gas but very low permeability), require detailed planning of every facet of exploration, drilling, stimulation and production. Several service

companies offer integrated operations (IO) software that allows operators to co-ordinate geophysical, geological and engineering disciplines (including Halliburton's Digital Asset, Baker Hughes' JewelSuite and Schlumberger's Petrel). Using IO software to analyse seismic, geological and petrophysical data, integrated geoscience and engineering teams can determine optimal well spacing patterns, length of well laterals, stimulation patterns and surface processing facilities.

During the planning stage, 3D visualisation centres are occasionally used, but the devices are expensive. Touch tables are emerging as a more reasonably priced and versatile visualisation device. Essentially, the touch-screen monitors (up to 80 in. lateral size) are mounted horizontally to allow geoscientists and engineers to gather round and collectively interact with data. "There's a lot of interest in touch tables," says Godin. "You can use it to create a virtual map, using geographical, seismic, geological and drilling information. Right now, they're used in schools and conferences, but they're coming to oil and gas in a big way soon."

Rigs

New rig technologies are playing an important role in reducing drilling time. The conventional rig with fixed derrick and manual rig floor is rapidly being replaced by automated drilling rigs (ADRs). The derrick has been superseded by a self-erecting hydraulic telescoping mast. The mast itself has a hydraulic top drive built in, and is equipped with a torque wrench and automatic pipe handler. Conventional manual tongs have been upgraded to hydraulic power tongs.

The rig functions are controlled by various joysticks that raise, lower and stop the travelling blocks and operate the pipe handler rotation. Drilling information can be displayed in real time, and compared to historical performance in order to consistently optimise weight on bit (WOB) and rate of penetration (ROP).

ADRs reduce non-productive time (NPT) dramatically. While conventional rigs may require 20 loads to move from site to site, comparable ADRs can have as little as four, with the self-erecting mast and other components mounted onto trucks, trailers and skids. Some rigs that are designed to drill multiple wells on the same pad use a hydraulic system in the substructure to 'walk' the rig at speeds of 15 - 30 ft/h between wells. These innovations can add 45 - 75 drilling days per year compared to a conventional rig of similar capabilities.

Oil companies are also investigating entirely new forms of rigs that can be transported by air. Calgary-based Cenovus leases several million hectares of land in the oilsands. In order to evaluate the land, it must drill and core thousands of shallow wells. Since the region is covered in soggy muskeg, access is limited to a few winter months when the ground is frozen.

In an effort to extend the drilling season, Cenovus partnered with SkyStrat Drilling to create a shallow drill rig that could be dismantled and shifted on site by helicopter. The joint venture brought in hard-rock drilling experts, who worked with oilpatch veterans to create a hybrid rig – essentially a hard rock coring drill with blow out preventers and a mud system – that could be broken down into 6000 lb components, small enough to be carried by helicopter.

After pilot testing, the rig was brought into service in 2012. So far, it has drilled over 30 wells using helicopter support. The wells consume 50% less water than conventional rigs and cost 25% less to drill. Cenovus and SkyStrat are building a second rig incorporating new innovations, and expect to drill 50 rigs a year, about 10% of Cenovus's annual programme.

Downhole

Steerable mud motors, which use a mud-driven turbine in the bottomhole assembly (BHA), are now being replaced by rotary steerable systems (RSS). The direction of the steerable tool is measured while drilling (MWD), using a directional module that measures inclination and azimuth using triaxial magnetometers and gravity sensors. The system contains a transmitter/receiver to send data uphole through the mud system and receive commands back downhole. Logging while drilling (LWD), enables the operator to keep the tool in the productive reservoir. Baker Hughes' AutoTrak Curve RSS can drill vertically, curve through up to 15°/100 ft, and continue on for the horizontal sections in one run, eliminating two trips.

Oil companies are embracing the new technologies. Nexen is one of the major operators in the Horn River Basin of northwest British Columbia (BC). The Liard formation, a tight shale, holds an estimated 140 trillion ft³ of recoverable gas. When the Calgary based company first started drilling in 2009, their rigs averaged 100 m per day, and it took six weeks to reach TD of 3700 m.

Although the wells were prolific, it costs around C\$ 100 000/d to drill in the remote region, stretching the economics to the limit. In order to save time and money, Nexen decided to incorporate the most effective technologies and processes available.

Nexen replaced the Kelly-equipped rig with a top drive, and ditched mud motors in favour of a rotary steerable system. It eliminated the 4 in., two-casing string design and opted for a 5 in. monobore that eliminates intermediate casing and allows the company to drill to TD with just surface casing. They optimised rig movements by installing hydraulic stompers that lift the entire rig and move it 5 m to the next well site. All connections, including power, mud and water, are on an umbilical system that allows them to stay in place during the move.

As a result, Nexen now drills an average of 350 m/d in the Liard formation, and finishes a well in under 12 days, resulting in US\$ 60 million of savings per 20 well pad.

Stimulation

Once a well is drilled and cement-cased, the shale must be stimulated in order for the petroleum to enter the wellbore in economic volumes. Much research and development is focused on making the process more efficient and economical.

In a traditional perforation and fracturing completion, a service company lowers a perforation gun to the reservoir interval and sets off explosive charges that create perforations in the casing. On the surface, water is mixed with proppant (sand to hold the fractures open) and proprietary chemicals (to reduce viscosity and allow further penetration). The water is then pumped down the hole at high pressure, fracturing the rigid shale reservoir sufficiently to allow large volumes of trapped hydrocarbons to escape.

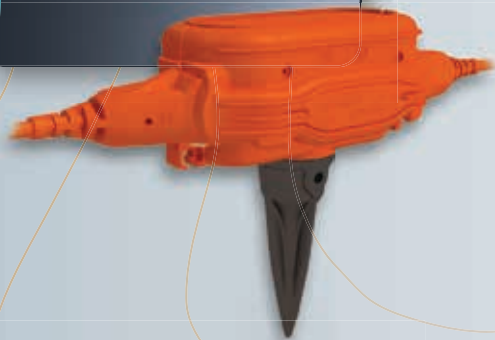
Halliburton recently adapted production-sleeve technology to the fracturing operation. The RapidFrac system uses a metering process that enables a single ball to open multiple sleeves isolated within an interval by swellable packers. Up to 90 sleeves can be incorporated into any one horizontal completion, ensuring maximised stimulated reservoir volume. In a paired set of test wells in the Bakken, Halliburton was able to cut the fracture time from four days to two days and significantly reduce water usage.

Because the performance and direction of fracturing is so important to efficient production, operators have relied on

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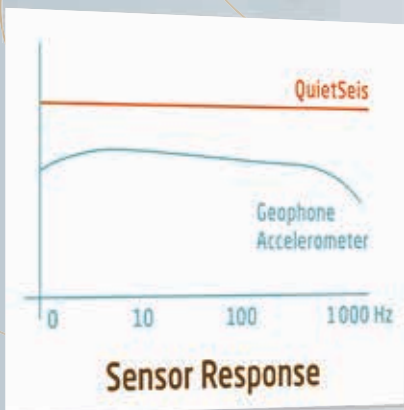
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downhole devices (such as tiltmeters and microseismic) to get a sense of the direction and penetration of a fracture. The intense heat and pressures in wellbores mean that only the most robust devices are able to measure pressures and other variables, whereas microseismic is distanced from the actual well. In addition, if a fracture job goes awry, engineers often only have surface pressure fluctuations to guide their remediation.

Service companies are now adapting fibre optic systems (developed by the military) to various downhole processes, including Schlumberger's WellWatcher, and Halliburton's FiberWatch. The fibre optic is the downhole part of the system; a laser generator and photo sensor sit at the surface. By sending laser pulses down the cable, operators can monitor temperature and strain-sensitive responses along the entire length of the wellbore.

Fibre optic systems are being adapted for hydraulic fracturing in order to tell if there is stage overlap, a leaking plug or poor casing cement. They can also monitor where a ball drop is in each sleeve, and allow remediation in real time when problems arise. In addition, since the optic cable can be embedded in the casing, the technology allows companies to ascertain in detail the lifecycle of the well; this information is invaluable in planning out the well-spacing, orientation and fracturing programmes for the thousands of wells that might eventually be drilled within the unconventional reservoir.

Much concern focuses around stimulation through hydraulic fracturing. Critics are worried that the process uses up valuable water resources and injects harmful chemicals that have the potential to pollute groundwater. Several states have enacted legislation restricting hydraulic fracturing, and other jurisdictions, including Quebec and France, have instigated blanket bans.

Service companies are focusing R&D to ensure that hydraulic fracturing can proceed in a safe, sustainable manner. Calgary-based Aqua-Pure has developed a mechanical vapour recompression evaporator mounted on truck-transportable skids. The system converts contaminated fracture flowback water into pure water at a rate of 60 gpm (13m³/h).

Chesapeake Energy, one of North America's largest natural gas producers, is experimenting with fracturing additives composed solely of environmentally benign components. Various mixtures of the 100% green fluids are being field tested in wells throughout the US.

Gazing into the crystal ball

In the future, technologies that have never been associated with oil and gas will be integrated into a variety of uses. "We are hearing about a vast improvement in satellite observation," says Godin. "Canada and the EU are launching a new generation of satellites. The revisit time will go up, and the costs will come down."

Oil and gas can benefit in a number of ways. Environmental regulations, for instance, require operators to adhere to various parameters, including road cuts, water usage, flaring, etc. Companies normally comply with manual inspections, which can be very labour intensive. "You can now monitor visible surface activity with satellites," says Godin. "There are satellite images of flaring from North Dakota wells. The images are not granular enough to be able to say that well location #510 is emitting 10 m³/h, but in 5 - 10 years, satellite imaging might be precise enough to meet government and company needs."

A robot is a mechanical device guided by software or electronic circuitry, allowing it to manoeuvre or conduct simple repetitive tasks. Most robots are used in assembly lines,

where they perform repetitive actions, such as welding. "Oil and gas researchers are looking at robots for applications in environmental monitoring and pipeline ROW inspection," says Godin. "There are also possibilities on drill rigs, where they could be used as a robot arm to handle drill pipe."

Unmanned aerial vehicles, or UAVs, have become inexpensive and robust. Recently, Amazon announced a quadcopter UAV system capable of delivering a 2.3 kg package within 15 km of its warehouses within 30 minutes. Uses are now being investigated for the energy sector. "UAVs make sense in high density sites, such as offshore platforms, where they can be used to do visual inspections of stacks and tall structures where it is difficult for a worker to reach," says Godin. "Onshore, you would have to look at cost-benefit analysis to find where such devices make sense."

Micro-sensors, devices smaller than 1/1000 mm, are now widely used in the telecommunications sector. "Smart phones have micro-gyros that tell the phone if it is being held upright or sideways," says Godin. "The micro-gyros exist because there are hundreds of millions of people who want smart phones. The oil and gas industry is big, but the need for a micro-sensor might be in the 10 000 to 100 000 range, several orders of magnitude smaller. You would have to make a business case for using them in the sector."

Information and communication technology, or ICT, is poised to take the oil and gas sector by storm. "We are entering the realm of big data, in which we collect huge amounts of information from multiple sources," says Godin. "There are many hidden trends in the data, and we'll need applications that allow oil and gas information to increase value."

In Canada, ICT professionals and oilpatch participants are planning a forum in Calgary in which the two worlds will unite. The Canada 3.0 conference will feature workshops in which both parties can get together and discuss challenges that the oil industry faces, and potential ICT solutions.

Members of the Petroleum Services Alliance of Canada (PSAC), for instance, are finding it difficult to find and retain skilled labour. "They can use ICT to deploy personnel more efficiently, and lower accidents; it's an absolute fit," says Mark Salkeld, President and CEO of PSAC. "ICT can also be used to gather machine performance data that can be analysed in order to increase reliability and predictability."

The mission of the Petroleum Technology Alliance of Canada (PTAC) is to facilitate innovation, collaborative research and technology development and deployment for the Canadian hydrocarbon industry. "There is a big question in the oilsands around how to establish the growth of a steam chamber in SAGD (steam assisted gravity drainage), and learn how it moves," says Soheil Asgarpour, CEO of PTAC. "A good SOR is when the steam goes where it is supposed to, and a poor SOR is when it didn't go where it was supposed to. In the latter, the costs and greenhouse gases go up. If we had a tool to tell us where it is going, it would help us decide the actions needed to improve the SOR. Canada 3.0 is a two way avenue; ICT professionals can learn about oil and gas' challenges, and oil and gas can learn about what is out there to help."

In conclusion, much R&D is being done to incrementally improve the effectiveness, efficiency and cost of a host of upstream processes. But, just like horizontal drilling and hydraulic fracturing proved to be a paradigm shift for the sector, the next groundbreaking transformational innovation awaits in the wings. ■

Image courtesy of Baker Hughes.



SHALE SCIENCE ALLIANCE

Neil Peake, CGG, and Bill Whatley, Baker Hughes, explain how two companies working together to combine their geoscience capabilities and reservoir description services can offer an improved understanding of how to optimise reservoir development.

Shale gas and tight oil development is becoming a significant part of the global energy mix, led by North America. Part of the attraction of these extensive onshore plays has perhaps been that they were considered low-risk and easy to produce compared to the challenge of the deepwater, sub-salt plays in the same region. However, as shale play development ramped up in the US, this preconception was dispelled by mixed production results.

Today, despite advances in drilling and completion technology, many operators are struggling with inconsistent or lower-than-expected production. Recent studies of US shale plays reported the following sobering statistics:

- ▶ 70% of unconventional wells in the US do not reach their production targets.¹
- ▶ As much as 75% of each hydraulic fracture (15 - 20% of stages and 35 - 40% of perforation clusters) fail to contribute to production.²

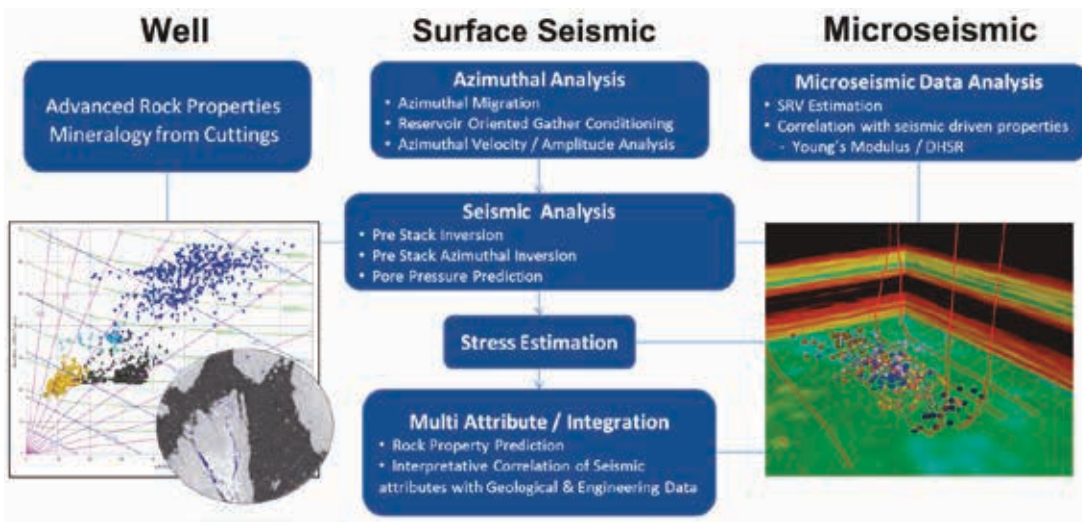


Figure 1. Integrated geoscience workflow for a shale play, incorporating numerous disciplines to high-grade the survey area to identify 'sweet spots' and optimise drilling locations and completions. From Castillo et al., 2014.

at the well and field-wide seismic observations to improve reservoir knowledge and reduce subsurface uncertainty, with a focus on shale plays.

Activities for the alliance have focused around the intersection points of their respective expertise at the key stages in shale play development:

- ▶ Identification of production sweet spots.
- ▶ Optimisation of well placement and drilling programmes.
- ▶ Improving completion design and fracture performance.

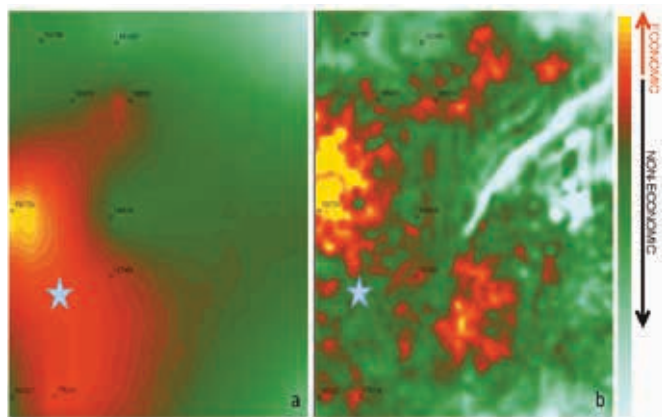


Figure 2. Comparison of a map of interpolated production values (a) and the predictive map of the productivity index from the integrated geoscience workflow (b). Areas in yellow and red indicate locations of wells with high enough production to make them economic. Wells in the other areas are non-economic. The high variability in the factors affecting production in the Haynesville play are well illustrated in (b) as are the risks of basing drilling decisions on sparse well data alone.

What has become clear is that shale resource plays are not necessarily easy targets. Each play is unique and within each one there is variability or heterogeneity in the factors that influence production. This is compounded by the fact that many companies entering these plays are challenged by scarce subsurface data and limited experience. According to one of the studies, 73% of operators say they do not know enough about the subsurface.¹

As a result, many operators have resorted to 'statistical drilling' and 'geometric completions' following predefined trajectories, spacing and parameters. These practices have led to many wells being placed and completed in reservoir intervals with unfavourable properties.

In this situation, determining where to begin drilling and even where to invest in acreage can be challenging. More needs to be done to understand shale plays and to reduce subsurface uncertainty.

Strategic alliance

Given this context, CGG and Baker Hughes announced a strategic alliance in 2012. By combining their services and expertise, they aim to bridge the gap between measurements of rock properties

Projects have been conducted to develop geoscience workflows, which have resulted in recent encouraging case study publications,³ and further work is underway. The alliance has been strengthened by the realignment of the firms' VSFusion joint venture to focus on borehole and surface microseismic monitoring. The joint venture, now called Magnitude, strengthens the capabilities of the two companies in completion design and hydraulic fracturing. The announcement of an exclusivity agreement for the supply of RoqSCAN™ automated well site mineralogy analysis is a recent milestone for the alliance; recent case studies show how the interpretation of automated mineralogy data has generated value.

An integrated geoscience workflow

In conventional and unconventional plays the E&P industry uses two main sources of measurements to build an understanding of the subsurface and the reservoir. Wells provide an opportunity to collect 'hard data' on the rocks in the form of core and cuttings samples as well as petrophysical and geomechanical information from an increasingly sophisticated suite of logging tools. However, wells with appropriate log data may be a sparse resource, particularly in exploration areas.

Geophysical data, and in particular 3D seismic, is the other main source of information. It provides field-wide coverage of the subsurface for structural imaging and for estimating the reservoir properties that can be determined from wave propagation.

The challenge is to properly integrate these datasets to provide an accurate subsurface model of the factors that influence production, allowing shale operators to make better drilling and completion decisions. This article illustrates how recent technologies have been put into action within this integrated workflow.

Identifying sweet spots with an integrated approach to seismic reservoir characterisation

The Haynesville shale was one of the earlier plays to be developed, with drilling activity peaking in 2010. As a gas play it was hit by the collapse in gas prices, but recently there has been renewed interest in the play as prices have recovered. As a mature play, there is production information available from

the existing wells. Typically, well performance varied wildly so this presented an interesting opportunity to perform an integrated study.

CGG was commissioned to perform seismic reservoir characterisation on the organic-rich Upper Jurassic Haynesville shale to try and identify sweet spots for infill drilling.³ The project used CGG multi-client 3D seismic data, well logs, RoqSCAN quantitative mineralogical information from cores and cuttings and microseismic data.

The workflow in Figure 1 shows how the data were utilised to look at two different aspects of the reservoir. Firstly the 'reservoir quality' in terms of composition and resource in place, and secondly the 'completion quality' in terms of the ability to recover the resource in place, which is governed by the geomechanical properties, natural fractures and stress regime.

Petrophysical analysis of the well logs was supplemented by mineralogical analysis of core and cuttings to provide more accurate petrophysical models for seismic inversion and lithofacies classification. In terms of identifying the reservoir quality factors for the Haynesville it was determined that increasing gas volume could be associated with decreasing Vp/Vs ratio, Poisson's Ratio and Lambda-Rho and that increasing total organic carbon (TOC) was associated with decreasing density.

Using the well log and mineralogical data as training datasets, commonly used descriptive reservoir attributes (i.e., mineral volumes, TOC, porosity, water saturation and lithofacies) were estimated and mapped with multi-linear regression prediction techniques.

An innovative global azimuthal inversion of pre-stack seismic data⁴ was used to derive fracture properties and eventually local in-situ stress fields. The stress estimations were supported by diagnostic fracture injection tests (DFIT), records of mud weights used while drilling and tri-axial measurements of oriented core plugs.

Now armed with an understanding of the likely factors controlling production, a multi-linear regression prediction was performed using the available well production data (estimated ultimate recovery). This statistically-driven method established a relationship between the volumetric descriptive reservoir attributes and the production results with a correlation of 73%. The attributes identified fell into three groups, the first being stress and fracture-related (closure stress; fast velocity, aligned with the HTI anisotropy plane and minimum curvature), the second being mineralogy-related (VQuartz, influencing brittleness) and the third being fluid-related (Vp/Vs ratio, indicative of gas volume).

This methodology and the mapped productivity index represent a big step towards quantitative sweet spot mapping based on seismic attributes calibrated and constrained by 'hard data' from the wells. In Figure 2, a simple comparison can be made between using interpolated production data to plan infill wells, and using the seismic-derived productivity index. The stark difference in these maps illustrates the high variability in the factors affecting production in the Haynesville play and the risks of basing drilling decisions on sparse well data alone. The blue star indicates a seemingly safe bet for infill well placement based on the interpolated figures. With the additional subsurface knowledge from the integrated workflow it can be predicted that this 'safe-bet' location will actually be non-economic.

Designing and drilling better wells

Having developed a reservoir model of lithological and geomechanical properties and having identified potential production sweet spots, the emphasis is on designing an efficient drilling and completion programme:

- ▶ The optimal lateral placement in the most prospective reservoir interval, exposing the maximum amount of productive reservoir to the well.
- ▶ The most effective drilling programme and technologies to mitigate subsurface conditions or drilling hazards that might negatively impact the wellbore.
- ▶ The optimal number of wells required to cost-effectively develop a lease position and beyond that maximise production.

Figure 3 shows schematically how these predictive models can be used to make better drilling decisions. Using nominal drilling and completion costs and observed production figures, some simple scenario testing can be performed with different well trajectories within the model and economic models can be generated to screen the options.

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Improving completion design and fracture performance

Assuming that a well has been accurately placed, the next step is to implement an efficient completion programme to optimise production. Production performance is highly dependent on fracture stage placement, design and treatment technique. Quoted statistics show that geometric fracturing techniques can result in a high number of non-productive stages and wasted fractures. Excessive stage placement, pumping horsepower and the wrong choice of fluids all lead to unnecessary cost. Only by properly characterising the reservoir along the lateral can an optimum programme be designed.

Whilst this seismic-derived sweet spot mapping is sufficient for drilling patterns and well placement, it is logging methods that will provide the required detail for completion design. Regrettably, less than 10% of the 15 000 horizontal wells drilled annually in the US are logged.⁵

Filling this information gap along the lateral section is where the RoqSCAN automated mineralogy service⁶ comes into play. In real time at the wellsite scanning electron microscopic (SEM) and energy dispersive x-ray (EDX) analysis can be performed on cuttings samples providing quantitative mineralogical and textural data and key elemental organic proxies calibrated back to measured TOC data. These data have many applications including landing point characterisation, reactive and proactive geosteering based on mineralogical zonation and detailed reservoir characterisation. Its specific value for unconventional resource plays is the application of the mineralogical and textural data to derive a proprietary brittleness index log (RoqFrac™), which can be used to guide completion design. Figure 4 shows how this information was used to tailor the completion design (both placement of stages and choice of fluids) for a well in the Barnett Shale.⁶ The result was positive, with even production from all stages.

This model of brittleness from the well provides another calibration point for seismic estimates of brittleness and can be fed back into the workflow. In the case of the Haynesville case study described earlier, RoqSCAN was run retrospectively on drill cuttings, allowing a comparison of these relative brittleness indicators. This information can be used to further refine and constrain the predictive lithological and geomechanical volumetric models derived from the seismic. Scenario testing can be performed to find the best design to maximise return on investment as shown in Figure 5. A typical geometric completion design (in this case showing 13 evenly spaced stages) can be optimised by firstly removing stages in areas predicted to be too ductile to support fracture networks and which will therefore not contribute to production. The parameters and fluids can then be

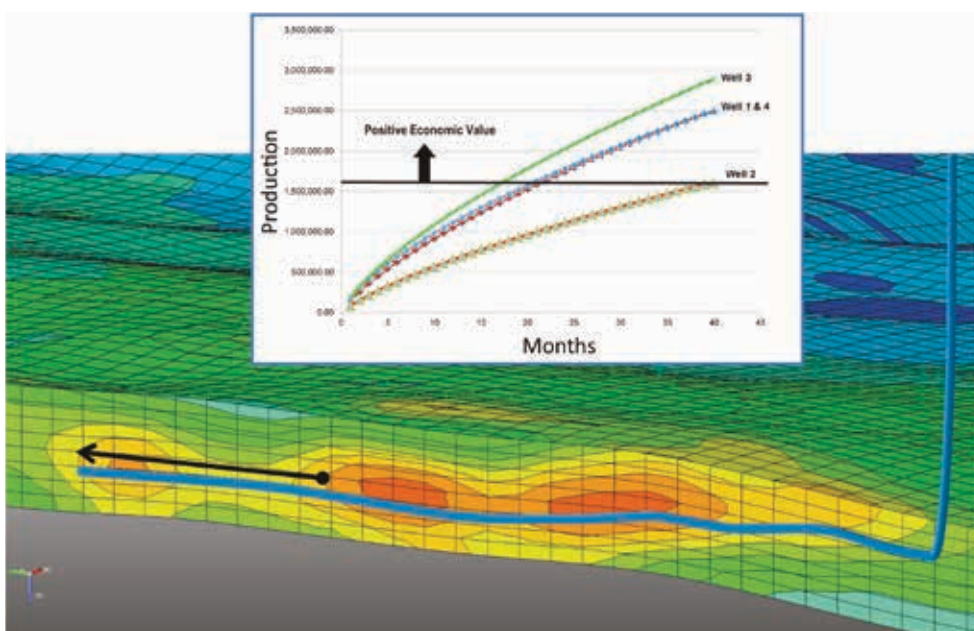


Figure 3. Scenario testing for well trajectories using the productivity index sweet spot model. Based on nominal drilling and completion designs and costs, economic models of wells can be developed. In this case the black arrow indicates the extension of a lateral to contact an additional sweet spot beyond the toe of a typical 5000 ft lateral section. This represents the difference between Well 1 and Well 3 on the inset chart.

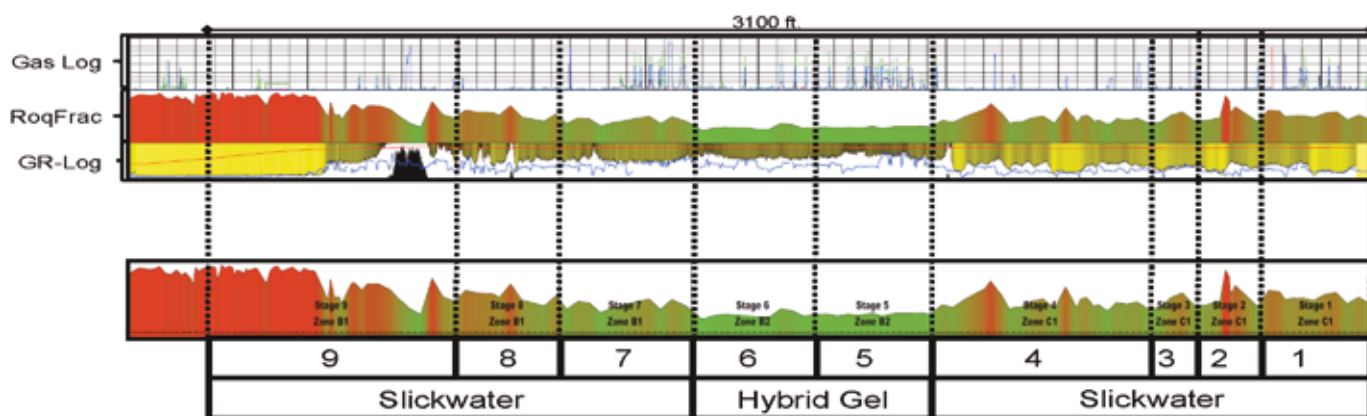


Figure 4. Completion scheme for a lateral showing the placement of the stages and choice of fluids based on a zonation scheme developed from the RoqFrac brittleness index. High values in red indicate brittle rock, low values in green indicate ductile rock. A composite including gamma ray and gas logs is shown for reference.

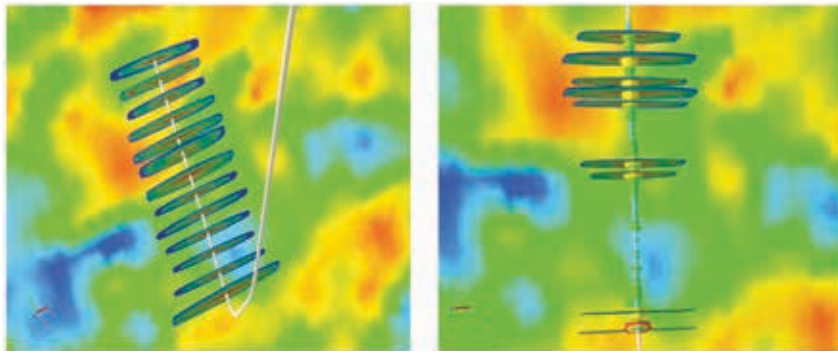


Figure 5. Optimising completion design using predictive models of brittleness and mineralogical analysis of cuttings. The geometrical 13-stage design is optimised by eliminating stages predicted to be non-productive in the ductile zones (blue and green), and refining the parameters for the stages in brittle zones (red and yellow). In the right-hand panel the RoqFRAC brittleness index (from analysis of drill cuttings) shown along the well path, and the seismic attribute map (Young's Modulus) share the same colour scale and show a good correlation.

refined for the remaining stages in the good zones (shown in red and yellow) predicted to be brittle.

No matter how good the reservoir models, or the understanding of the geomechanical properties and the stress regime, the reality is that the subsurface is a complex place and hydraulic fracture behaviour within the reservoir can be very different to what is modelled from wellbore data and logs. Magnitude, the Baker Hughes–CGG joint venture, provides the services and expertise to help unravel the sometimes complex story of hydraulic fracture development.

With real time onsite services using either surface patch arrays, permanent shallow buried arrays or downhole wireline arrays, Magnitude uses waveform inversion analysis to provide reliable mapping of hydraulic fractures and valuable stress regime information from moment tensor analysis of microseismic response. Having this data calibrated in real time with the fracture models at hand allows completions engineers to confidently analyse the effectiveness of stimulation parameters, such as pumping pressures, fluid type and proppant type as the fracturing unfolds, thus allowing critical changes to be made to optimise the hydraulic stimulation.

The information gleaned about the geomechanical behaviour of the reservoir during hydraulic fracturing provides another 'hard data' input to further constrain and validate the predictive hydraulic fracture models based on calibrated seismic attributes and well logs. Such calibration of the fracture model with monitoring data enables the engineers to reduce the uncertainties remaining from the interpretation of injection engineering curves by confirming the contribution of each perforation cluster and stage as well as the actual fracture geometry against the classic bi-wing initial assumptions. In the Haynesville case study, microseismic data (from 76 fracture stages) was available. Stimulated reservoir volume (SRV) was interpreted for each stage (see example in Figure 6) and then within each SRV bubble seismic attributes from the reservoir models were averaged.

The results for dynamic Young's Modulus are shown in the inset cross-plot in Figure 6, indicating that the SRV is proportional to it. A similar analysis was performed for differential horizontal stress ratio (DHSR), and although it is not shown here, the cross-plot indicates that SRV is inversely proportional to it. This spatial correlation of microseismic events with specific seismic attributes implies that both are governed by the same in-situ properties, and that the workflow modelling assumptions are valid.

A quick interpretation of these observations is that increasing Young's Modulus is indicative of increasing brittleness, which results in fractures propagating further and a larger SRV. Increasing DHSR however, implies that induced fractures will form increasingly along the axis of minimum stress, creating aligned fracture swarms, which are distributed more linearly and result in a lower SRV. This analysis is purely qualitative. However, further work will enable the use of this microseismic data for quantitative calibration of the reservoir models.

Further analysis incorporating production results with localised stress regimes, geology, natural fracture logs and microseismic analysis can highlight which dominant component of the stimulation strategy actually contributes to productivity in a given play.

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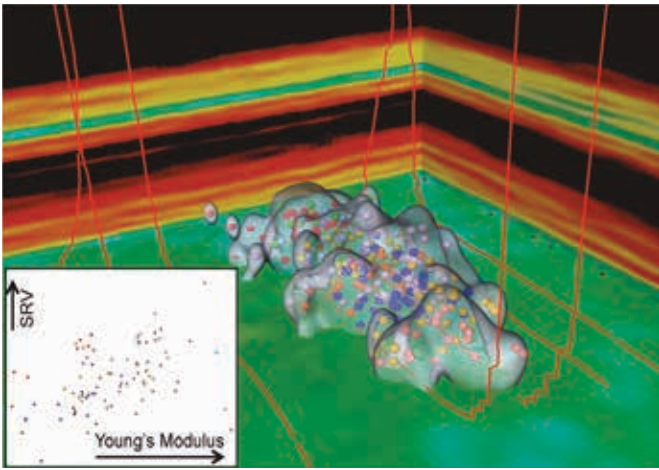


Figure 6. Microseismic events from one lateral in the Haynesville study area. Events are colour-coded per stage (11 stages for this lateral) and the interpreted SRV for all the stages is shown as a bubble around them. The inset graph shows the correlation of averaged seismic-derived Dynamic Young's Modulus within a single-stage SRV with SRV size (2D SRV area in this case).

Next steps

There is growing recognition in the industry that more can be done to understand the heterogeneous nature of shale resource plays and that this can only improve the economics of their development. This article has demonstrated how new

technologies are being integrated into a multi-disciplinary geoscience workflow to address this need.

Developing shale assets is capital-intensive, 'factory' drilling schedules are demanding and cash flow is a priority. However, operators should evaluate their data and ask themselves if they really understand the uncertainties well enough to derive maximum returns. Taking the time to collect value-adding data and properly apply it can give them a significant benefit. Whether that is in identifying the best acreage, improving operational cost-efficiency or increasing the IPR and/or ultimate recovery, this can have a real impact on the bottom line. ■

Acknowledgements

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GETTING A GRASP on basalt

No one said it would be easy to image structures in complex basins with salt and volcanic rocks. But it is possible, and this should be viewed with interest by oil and gas companies who want to save themselves the cost of drilling through basalt that they did not think was there.

In the last ten years, the CSEM method has been used as a direct hydrocarbon indicator, but electromagnetic (EM) surveys have also been found to be very useful in salt and basalt settings where the flanks and/or the base are not well controlled.

Moreover, EM measurements can complement other geophysical data, particularly in settings where high-impedance volcanic rocks or salt make the interpretation of seismic data challenging.

Siobhan Ryan, Electromagnetic Geoservices (EMGS), Norway, examines how integration of seismic with the controlled-source electromagnetic method (CSEM) and magnetotellurics (MT) can help oil explorationists outline and identify sedimentary layers and basement structures below basalt.



By using a multi-disciplinary approach, which integrates seismic, CSEM and magnetotellurics (MT), oil explorationists can secure complementary data for an improved mapping of a basalt complexity. They can incorporate the additional structural

information about the base of basalt, sediments and basement into their models. The updated structural models can in turn be used to improve the seismic velocity models, which will lead to better seismic imaging results. That can effectively reduce exploration risk by providing oil and gas producers with enough additional information to perform a better basin – and prospect risk analysis.

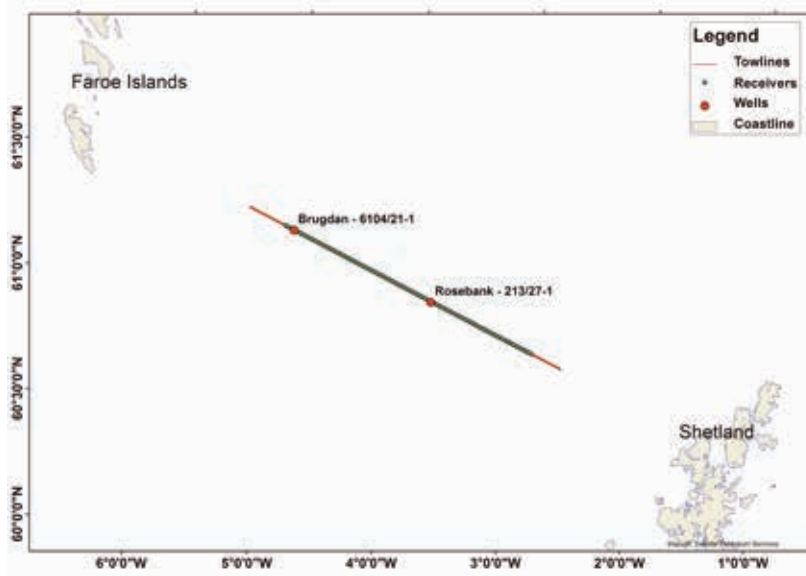


Figure 1. Map showing the location of the CSEM/MT survey, which was carried out between the Faroes and the Shetland Islands. The survey schematic has been simplified. Source reprinted with permission of EMGS.

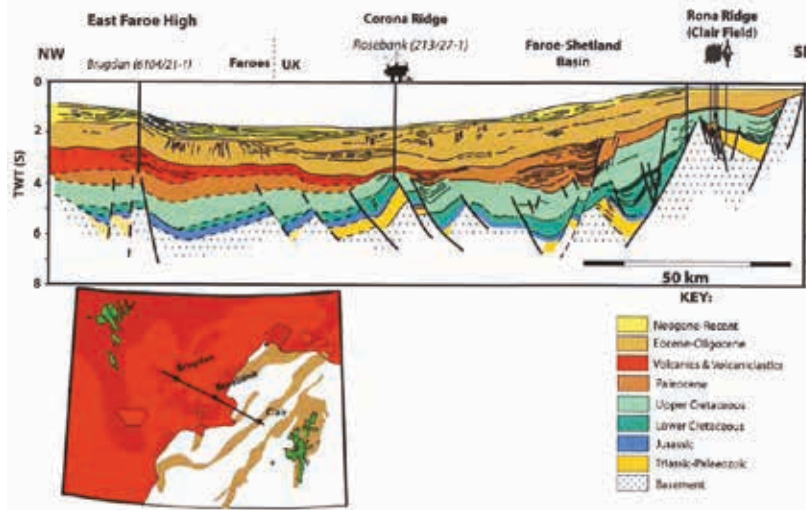


Figure 2. Schematic geological cross-section through the Faroe-Shetland Basin. Source: Schofield & Jolleys 2013 (modified after Gallagher & Dromgoole, 2007). The inter-basaltic Rosebank discovery is located in lava sequences above the Corona Ridge.

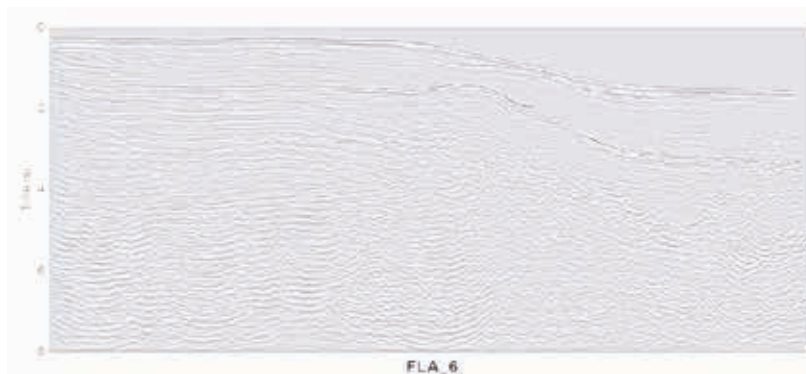


Figure 3. Before EM. The seismic image illustrates the difficulty seismic has in imaging below basalt. Courtesy: Jardfeingi.

Velocity models of basalt hardly possible with seismic alone

Seismic and well data have long been, and will continue to be, trusted methods, which are, in addition to geological data, valuable tools for the asset team’s decision-making process. However, traditional methods alone have proven challenging for companies who explore in areas where basalt is present.

Basalt is complex and challenging for seismic, so challenging in fact that it is hardly possible to derive a velocity model for basalt based on seismic alone.

Seismic identifies top basalt but struggles with the base and sub-basalt. During seismic surveying, most of the acoustic energy is reflected at the top basalt, due to the high impedance contrast. In addition there is internal scattering and interbed multiples within the basalt layer, which further dilute the image. This in turn makes it challenging to derive good velocity models, which are a prerequisite for seismic-depth imaging.

New methods in seismic acquisition have, for example, enhanced the quality of seismic wave-fields reflected from sub-volcanic structures. For example, Van der Baan et al. (2007) discussed the generation and preservation of lower frequencies and wider azimuth survey geometries to improve the quality of the reflected signal.

However, according to Deeds et al. (2013), the expenses involved in properly testing these new methods in the field have prohibited them from being used.

About the EM methods

By integrating the electromagnetic methods CSEM and MT with seismic, it is easier to manage the basalt and map how thick the layers are as well as how far they extend.

Basalt rock is highly resistive, while water-wet sediments have low resistivity.

In controlled-source electromagnetic (CSEM) surveying, a powerful horizontal electric dipole is towed approximately 30 m above the seafloor. The dipole source transmits a carefully designed, electromagnetic signal into the subsurface. The emitted electromagnetic signal propagates through the subsurface and is measured at seabed nodes.

The electromagnetic field registered at the nodes depends on the resistivity distribution in the subsurface. Electromagnetic energy is rapidly attenuated in conductive sediments, but it is attenuated less and propagates faster in more resistive layers like basalt and basement structures.

An image of the resistivity distribution in the subsurface can then be reconstructed using a numerical inversion process.

In a similar way to CSEM surveying, the MT surveying technique is sensitive to resistivity distribution in the subsurface.

The marine MT method can map subsurface resistivity variations by measuring naturally occurring, time varying, electric and magnetic fields that propagate through the subsurface and are measured on the seabed.

These fields are generated by the interaction of the solar wind with the Earth's magnetic field. This MT signal has very low frequency, which improves the depth penetration, but at the cost of poorer resolution. MT data is measured inherently during a CSEM survey when the dipole source is inactive or far away. Also for MT data a numerical inversion process is needed to reconstruct the resistivity distribution in the subsurface.

CSEM and MT data can then be inverted jointly in order to find a resistivity model that explains both datasets.

The structural information one can retrieve from CSEM and MT imaging is useful in its own right. If oil and gas explorationists knew the thickness of the basaltic rock of an area of interest, that alone would be valuable information if they had considered drilling into the rock.

At a more basic level, knowledge of the thickness of the basalt, thickness of sub-basalt sediments and depth to top basement is useful for building a structural model of a frontier area.

Case example: West of Shetland

West of Shetland, the volcanic complex contains flow-basalts, volcanoclastics and intrusives. In Late Paleocene to Early Eocene times, a continental break-up between Greenland and Norway/Great Britain was followed by thermal uplift, volcanism, extension and seafloor expansion.

During deposition, the volcanic complex branched out, east of the Rosebank discovery. Geologists point to there being a typical succession of volcanoclastics at the base, a mix of volcanoclastics and flow basalts in the middle and thick flow-basalts at the top.

At the eastern edge, the succession of beds conflues with a prograding delta, giving rise to the Rosebank Play concept.

In the Rosebank discovery, fluvial to marginal marine deposits dominate. Along this eastern edge, seismic surveys and drilling have provided some information about the thinnest section of the volcanic complex.

However, seismic techniques are not well-suited to map the thickness of volcanic complexes or to see where sub-basalt, sedimentary basins terminate and deeper basement begins.

This is especially the case towards the Brugdan well west of Rosebank (Figure 2). In this area the interpretation of the base basalt is much more uncertain.

The seismic image in Figure 3 illustrates the difficulty seismic has in imaging basaltic rock when structural information below the top basalt is missing. This seismic image has mapped basaltic strata in the vicinity of the Brugdan well. Top layers are well-imaged, down to the top basalt interface. However, no structural information is visible (from the image) underneath the top basalt.

Basalt complexes are generally so immense that seismic undershooting is no option. So one ends up penetrating the rock both on the way down and up, scattering and losing most of the acoustic energy.

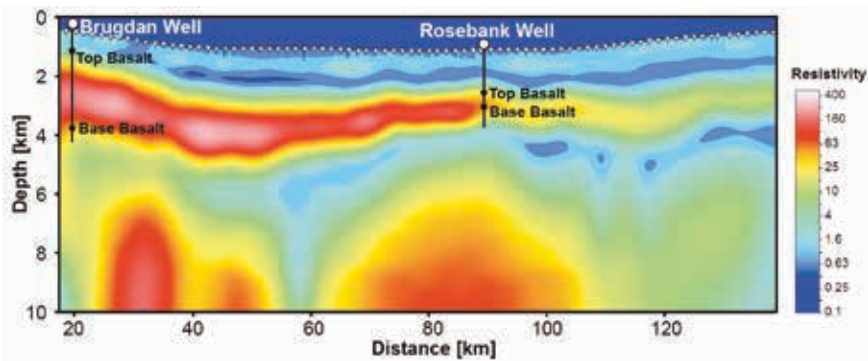


Figure 4. Joint inversion of CSEM and MT reveals resistive structures in red (like basement and basalt) and delineates these from the conductive sediment layers (indicated with green and blue colours). The Brugdan and Rosebank well locations are indicated by white dots, and reported top and base of basalt are marked with black dots. The western end of the CSEM/MT line is in close proximity to the seismic line in Figure 3. Source: EMGS.

In contrast, CSEM and MT can provide structural information about the sub-basalt, which can be used to improve existing geological models. Gross depth, shape, size and electrical properties of the subsurface structures can all be interpreted from the CSEM and MT results.

CSEM and MT joint inversion, West of Shetland

CSEM and MT data were acquired along the same profile as shown in Figure 2.

A significant number (84) of seabed receivers recorded signals along a 2D line with small grids around the Rosebank and Brugdan wells.

Figure 4 shows a joint inversion of CSEM and MT data from the West of Shetland EM survey. The CSEM data mainly contributes to the upper 2 - 3 km, while the MT data provides the general background information, especially related to large-scale structures such as basement and basalt.

The results clearly reveal a conductive (sedimentary) unit below the resistive basaltic complex (however, seismic and well-log data were not used to constrain the CSEM/MT inversion).

The red, arm-like formation protruding from the top left of Figure 4 shows the basalt layer. Note how well the EM joint inversion imaging of the basalt thickness corresponds to the top and base basalt markers provided by well data for Brugdan and Rosebank.

Moreover, EM imaging of Corona Ridge and basement in Figure 4 lends itself well to comparison with Figure 2.

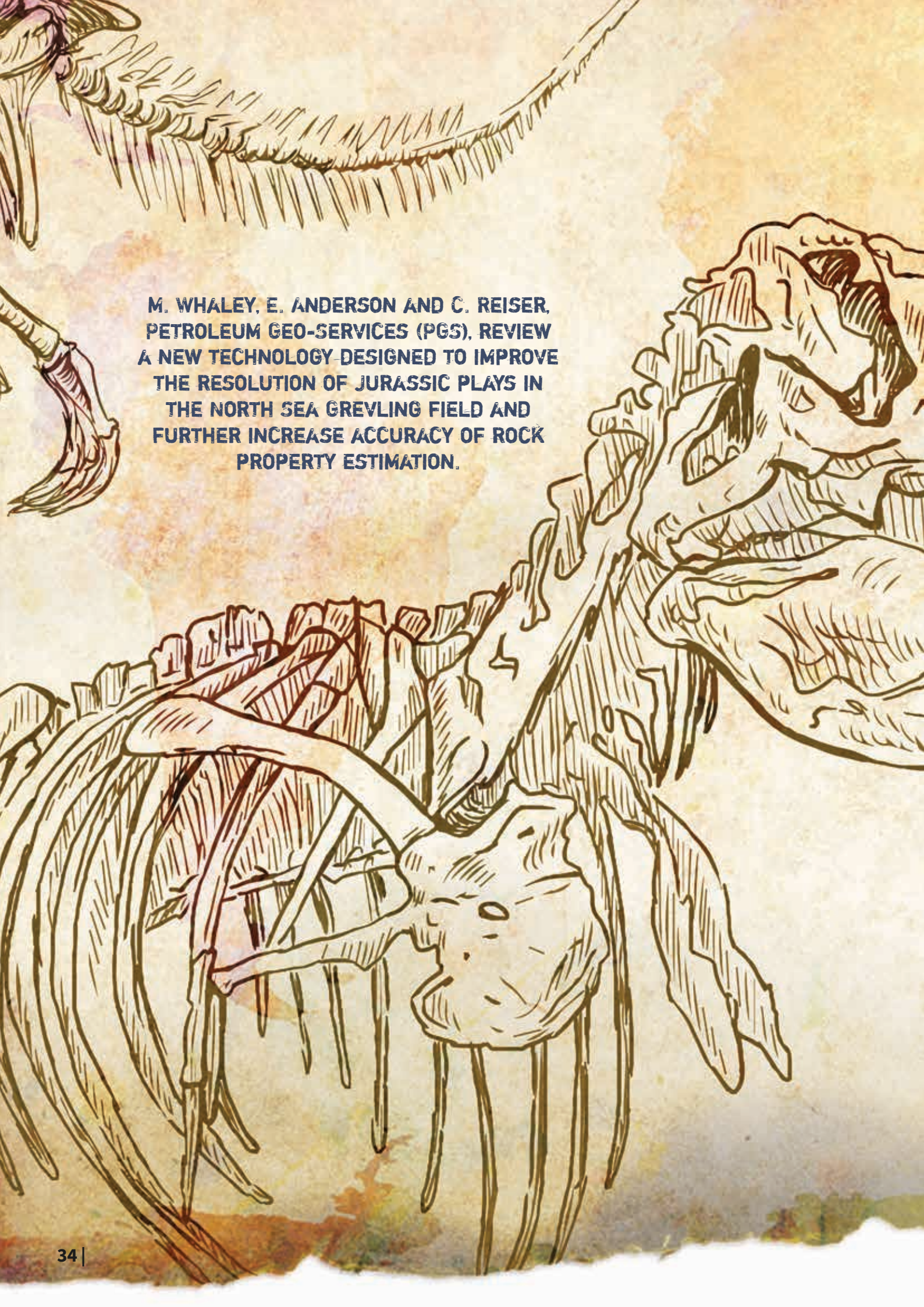
Contribute toward better structural understanding of sub-basalt

Geophysical research has grappled for years with the fact that basalts typically are very heterogeneous, with many different geometrical characteristics and physical properties. This keeps seismic waves from 'seeing through' the basalt with conventional methods.

Hence, trying to image through massive, basaltic complexes and into sedimentary successions has acted as a bottleneck for frontier exploration.

CSEM and MT provide structural information, which can be used to update structural models, and in turn update seismic-velocity models.

By integrating the three methods seismic, CSEM and MT, oil and gas companies can start cracking the codes of some enormous, and up until now, impenetrable areas. ■



**M. WHALEY, E. ANDERSON AND C. REISER,
PETROLEUM GEO-SERVICES (PGS), REVIEW
A NEW TECHNOLOGY DESIGNED TO IMPROVE
THE RESOLUTION OF JURASSIC PLAYS IN
THE NORTH SEA GREVLING FIELD AND
FURTHER INCREASE ACCURACY OF ROCK
PROPERTY ESTIMATION.**

EXPLORING THE JURASSIC



The North Sea is a mature hydrocarbon province that has been extensively explored with numerous commercial oil and gas discoveries. The UK Quadrants 14 - 16 area, specifically, has substantial proven oil and gas reserves in reservoirs from the Eocene to the Devonian age, yet estimates suggest that it may still contain up to 1.9 billion bbls and 3.4 trillion ft³ of 'yet-to-find' oil and natural gas.

As traditional plays become elusive, more sophisticated exploration techniques and tools are required. The petroleum industry has started to turn to new technology in order to identify and delineate leads and prospects based on pre-stack seismic, to quantify key reservoir properties, and to ultimately increase the probability of success. Nothing has advanced the field of seismic acquisition more than the development of dual-sensor broad bandwidth acquisition technology, helping to unlock the potential of exciting new plays. In the past, the use of hydrophone-only seismic acquisition limited the potential of seismic exploration,



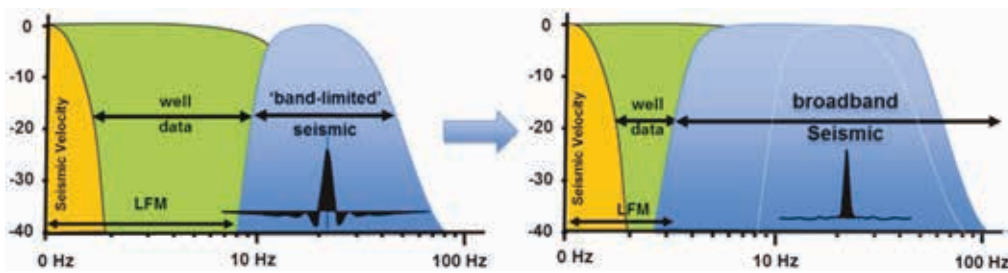


Figure 1. Left and right: schematic relationship of seismic velocity, well low frequency model and seismic bandwidth.

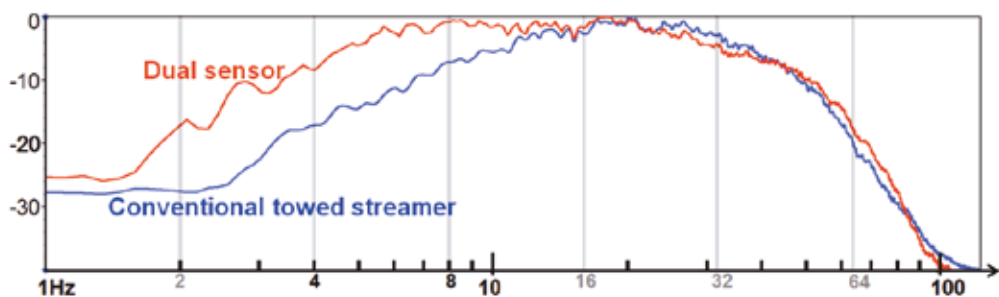
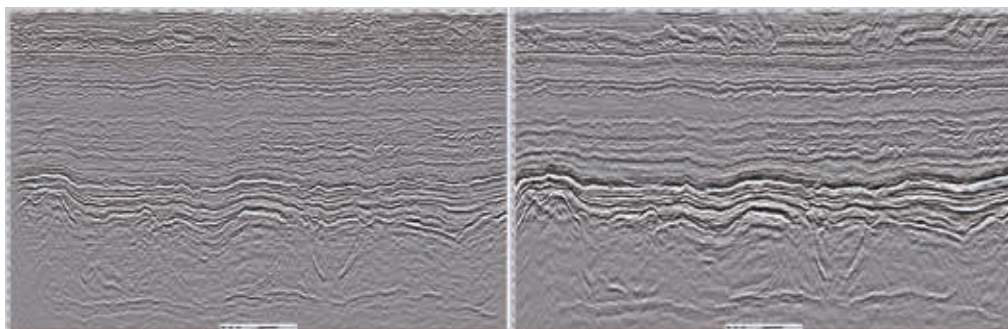


Figure 2. Top: seismic data comparison – conventional acquisition (left) versus dual-sensor (right). Bottom: conventional and dual-sensor streamer amplitude spectra on logarithm scale. Grey bars denote octave steps.

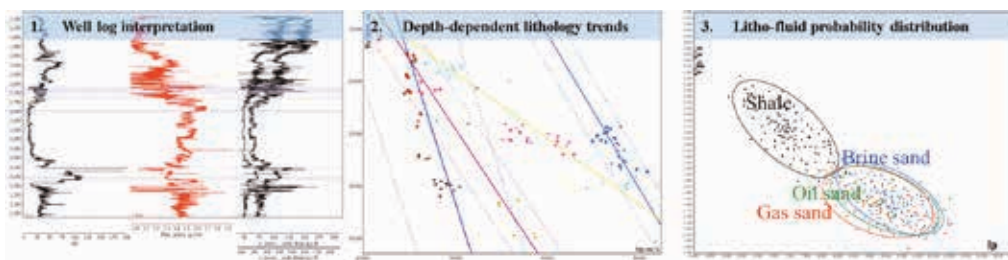


Figure 3. Rock physics model workflow: interpretation of well logs allows modelling of trends and probabilistic distributions of lithology-fluids, in V_p vs V_s domain.

given that acquisition had to be parameterised to optimise the data quality at one particular target depth. With the introduction of broad bandwidth streamer technology, new stratigraphic sequences have been revealed throughout the North Sea.

This article will show how technological advancements made in broadband acquisition technology have helped to improve the level of structural detail provided by the seismic data, which has led to the identification of promising new Jurassic targets.

The study area covers the Maureen and Grevling fields (UK Quad 16, Norwegian Quad 15). The Grevling field was chosen as a case study area because of its location in shallow water and because the Middle Jurassic and Upper Triassic oil accumulation is situated beneath a thick, high velocity chalk layer – a seismic imaging challenge not uncommon in many parts of the North Sea.

By comparing conventional and broadband dual-sensor datasets, the authors will be seeking to demonstrate that critical rock property information can be recovered from the additional low frequency information recorded by the broadband data. This additional low frequency information allows for better fluid discrimination within the reservoir interval and enables the estimation of a clear V_p/V_s trend directly from the recorded seismic data, without the need for additional well information.

Seismically derived rock property estimates are found to match the rock physics model computed from available well data very closely, validating the inversion workflow described within this article and the use of dual-sensor broadband data for such rock property studies.

Dual-sensor broadband recording

Conventional streamers using only hydrophone sensors have traditionally suffered from ‘ghost’ artifact in the recorded seismic data. The so-called ghost in a marine seismic recording is the result of an almost perfect reflection of the acoustic wavefield from the sea surface. Up-going waves are reflected back as down-going waves with a reversed polarity, and interfere constructively for certain frequencies and destructively for other frequencies. This phenomenon occurs both on the source side and on the receiver side. The affected frequencies depend solely on source and receiver depths. Conventional marine seismic acquisition therefore involves a trade-off between the various frequency ranges. To record high frequencies, sources and receivers have to be towed shallow, which strongly attenuates low frequencies.

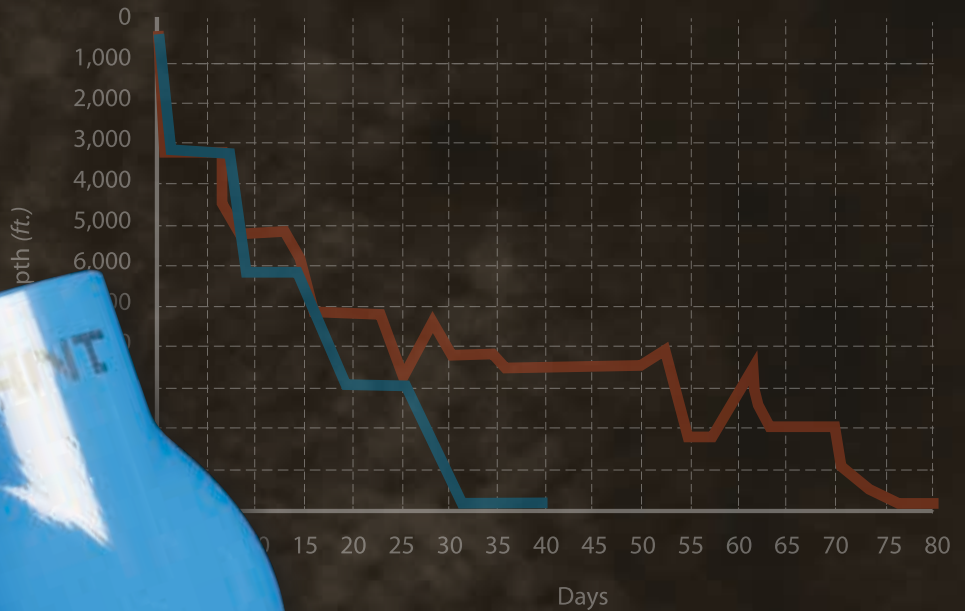
Conversely, a deep tow favours low frequencies at the expense of high frequencies.

To resolve the ghost notch issues inherent in conventional acquisition, a dual-sensor broadband streamer with co-located pressure and motion sensors called GeoStreamer® has been developed (Carlson et al., 2007). Such a streamer effectively enables removal of the receiver ghost while maintaining the efficiency of towed streamer acquisition.

The broader bandwidth achieved by removing the receiver ghost (Söllner, 2007) has crucial advantages at both ends of the frequency spectrum and, more recently, a de-ghosting approach has also been developed for the source side. By having a time and depth distributed source, the new source design – GeoSource™ – has allowed the removal of the source ghost (Parkes et al., 2011 and Parkes and Hegna, 2011). Eliminating both the source and receiver ghosts increases the seismic



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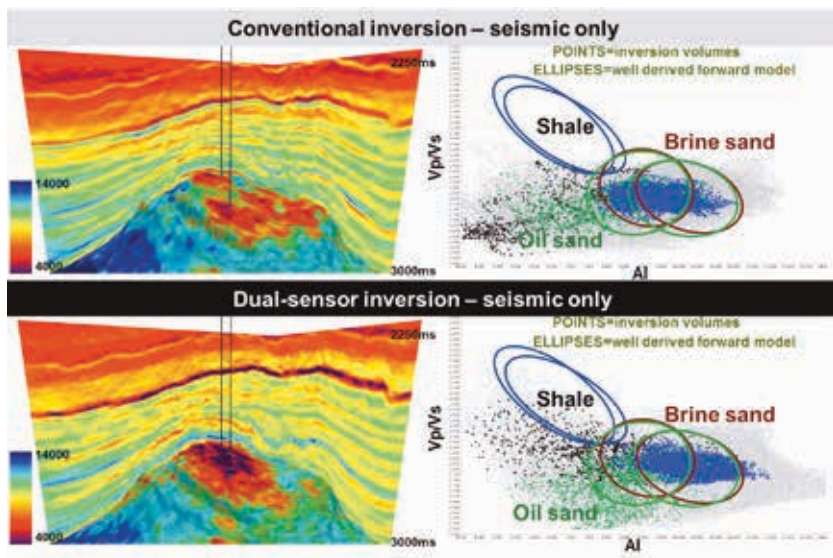


Figure 4. Comparison of conventional versus dual-sensor derived properties. Left: acoustic impedance estimated without any well data. Right: crossplots with data highlighted with points determined by the top reservoir and OWC from the well data. The grey points show the scatter of all points within the cube of data around the reservoir. The coloured ellipses show the predicted response from independent well model for two depths covering the reservoir interval.

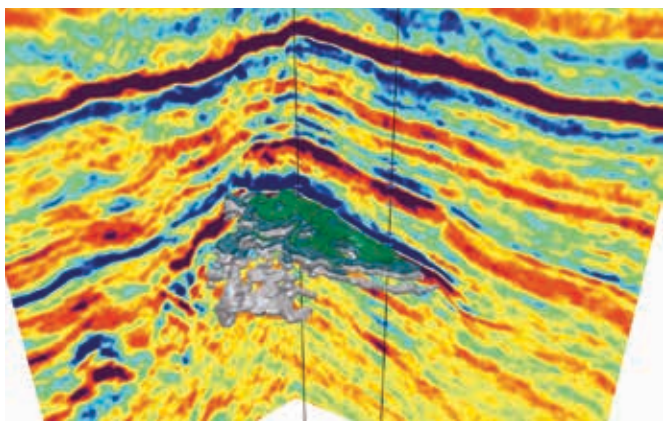


Figure 5. Litho-fluid probability prediction for Grevling GeoStreamer data.

bandwidth even more dramatically, which has a significant impact on the seismic image, as well as on the precision and fidelity of elastic properties derived from such data. This, in turn, enables improved understanding and characterisation of hydrocarbon reservoirs.

There are many potential benefits of broadband data, from increased resolution to improved inversion results (Carlson et al., 2007, Kelly et al., 2009 and Ozdemir, 2009). However, it is important to understand the information that is contained in the extra bandwidth. Accurately recorded low frequencies have the potential to change the way seismic data can be used in exploration and development settings, allowing new workflows such as the one described by Lafet et al. (2012).

Broadband seismic data can provide low frequency content down to 2.5 Hz (Reiser et al., 2012), depending on the geological setting and acquisition environment. For an absolute inversion of rock properties, the full range of frequencies down to 0 Hz is required. Conventionally, the seismic velocity provides the lowest frequencies (0 - 2 Hz) and interpolated well information fills the remaining gap in the recorded seismic frequency spectrum (Figure 1). This frequency gap, filled in with local well information, commonly represents at least two octaves, which has a significant impact on the seismic inversion predictability away from the well control. With lower seismic frequencies being accurately recorded by the dual-sensor streamer, the previous gap between frequencies

recovered from seismic velocities and the seismic data itself is significantly narrowed, allowing for rock property estimation without the use of any well information.

In this particular study over the Grevling field, a conventional dataset from 2005 was used. However, the data had recently been reprocessed through a modern processing workflow, allowing for a fair comparison between this legacy dataset and the latest dual-sensor data acquired over the same area. 2D sections of both datasets are shown below in Figure 2 together with amplitude spectra in logarithmic scale.

Deriving physical rock properties from seismic data

A relative pre-stack inversion was carried out on the conventional legacy data over the Grevling field to produce volumetric estimates of relative acoustic impedance (I_p) and shear impedance (I_s). A low frequency model was computed using only a seismic velocity and a density term to reintroduce the frequencies not recorded by the seismic acquisition.

Depending on the available *a priori* information, a depth-dependent density trend could be calculated for the survey area and applied to the inversion model.

Alternatively, a simple constant scalar can be applied to a first-pass estimation of absolute rock properties, potentially representing a significant improvement over relative impedance estimations.

For this case study, a rock physics model was developed from the available well data and used as a comparison with the seismic base rock property estimates. Well logs were interpreted to derive statistical depth dependent lithology trends (Figure 3). These rock property trends, based on the end members picks, were then used to produce probability distribution functions for the different lithology-fluid combinations. The resulting rock physics model was then used to determine the quality and accuracy of the elastic rock properties derived from both conventional and new dual-sensor broadband data.

Absolute rock property estimation

In order to demonstrate the importance of the additional frequency content of broadband seismic data for absolute rock property estimation, the inversion results from a workflow where no additional well information was used to constrain the low frequency model are compared. The 3D image on the top left of Figure 4 represents the absolute P-impedance computed from the narrow band conventional seismic. The image on the bottom left represents the result for the dual-sensor streamer data. A comparison of the images shows that the dual-sensor impedance estimates are significantly more stable and that they correlate very well with the known reservoir outline on the top of the structure.

The crossplots on the right of Figure 4 show the rock properties extracted from the inversion volumes based on polygons picked using the well information to accurately map the top of the reservoir, oil-water contact (OWC) and the extent of brine sand recorded in the wells. The dual-sensor streamer cross-plot distribution shows a much better fit with the predicted rock physics model (the coloured ellipses at two depths). It also indicates a much better discrimination between the brine and oilsand. The same constant scalar value was added to the V_p/V_s values for both datasets. However, the dual-sensor data has a clear V_p/V_s trend recorded in the low frequency of the seismic data (shale trend), whereas the conventional data mainly shows variation around the constant value.

When a pre-stack simultaneous inversion and lithology-fluid probability prediction is conducted, as shown in Figure 5, rock physics

forward modelling is consistent with the rock property predictions from the dual-sensor seismic-only. Lithology-fluid estimation is based on I_p and V_p/V_s volumes without well input. 3D bodies can also be defined based on the predicted oilsand probability.

An important note to make is that the rock physics model was independently derived and was not used in any way to constrain the seismic inversion. The properties do not match perfectly, as one would not expect from a relatively simple workflow such as the one used here. However, the results presented in this article demonstrate the benefits of the additional low frequency information provided by dual-sensor broadband data.

Conclusion

The demands placed on modern seismic data are multi-fold, but critically, the data must enable the confident identification and delineation of leads and prospects based on pre-stack seismic and to quantify key reservoir properties to increase the probability of successful exploration.

Most of the seismic interpretation and seismic reservoir characterisation work performed to date has had to rely on using relatively 'narrow' bandwidth seismic datasets, or seismic data that had a spectrum preferentially skewed towards either the low end (deep tow) or the high side (shallow tow) of the frequency range.

Dual-sensor broadband data, richer in both low and high frequency information, proves to be the preferred input for more precise and accurate derivation of elastic properties through seismic inversion, which for the first time is reliably possible without the use of additional well information.

A comparison with conventional data demonstrates that dual-sensor broadband seismic significantly improves the ability of assessing lithology and fluid variation across a field and/or prospect and subsequently helps

to successfully discriminate between oil and brine sands as confirmed by independently derived well log rock physics templates.

GeoStreamer dual-sensor data, with its greater frequency content, substantially reduces the amount and potential bias of *a priori* data input. It therefore makes the inversion or any quantitative interpretation solution less dependent on what is already believed and increases its usefulness in areas where *a priori* information may be scarce or uncertain, hence allowing for subsurface decisions to be made with much greater confidence. ■

Acknowledgements

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Martin Grolms, NEUMAN & ESSER, Germany, explores some of the latest developments in the field of oil-free compressor systems and explains how these systems can aid in the discovery of new oil and gas reserves.

The oil price, energy supplies and pipelines have had a significant influence on world politics for a long time now. The question of the energy supply today and in the future is a central factor in foreign policy, the economy and industry, environmental policy and traffic planning in most countries.

In 2011, global daily consumption rose to more than 90 million bbls for the first time and has remained more or less constant at this level. This is in excess of 14 billion litres per day to generate electricity, fuel nearly all means of transport and transport equipment, and manufacture plastics and several chemical products.

A CLEAR VIEW OF DEEP



Figure 1. Petroleum Geo-Services uses BLUESAPS from NEUMAN & ESSER for the new Ramform Titan seismic vessels. Source: PGS.



The exploitation of these huge quantities subjects the environment to dangers, which must be minimised with all efforts. Since the Deepwater Horizon catastrophe in the Gulf of Mexico it is clear that the entire production chain from crude oil to the ready fuel must be carried out with the highest degree of attention and foresight.

Seismic offshore survey

The production chain starts with locating crude oil reservoirs. For example, explosive charges were used for offshore searching up until the 1980s. Explosive devices generated the acoustic waves required to acquire seismic data and explore the sea floor. Stricter guidelines and regulations only reduce the burden for marine organisms due to seismic offshore activities as a result of the increased interest in protecting the oceans.

Today, the 'seismic vessels', as the search ships are called, virtually all use high-pressure air guns as pulse generators. A number of kilometre-long streamers filled with several hundred underwater

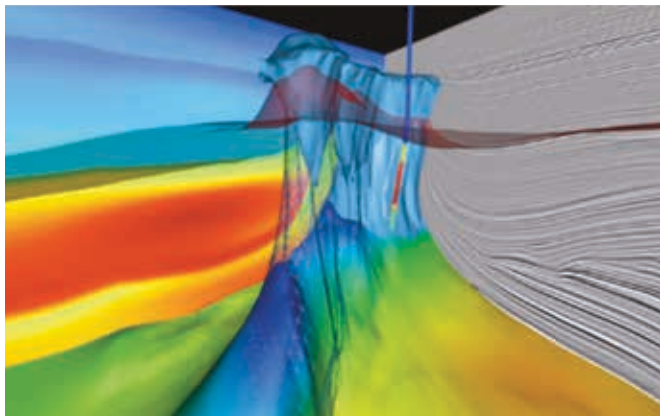


Figure 2. Seismic imaging is analogous to ultrasound technology used for medical examinations of the human body. Source: PGS.

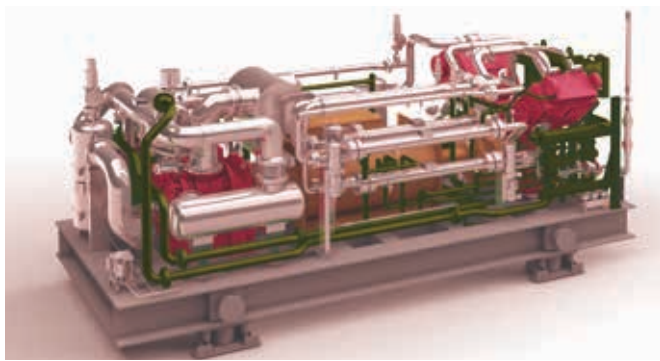


Figure 3. The new development BLUESAPS is the oil-free variant of the NEUMAN & ESSER Seismic Air Power System. It consists of a two-stage oil-free screw compressor and a three-stage oil-free reciprocating compressor that provides clean air up to a pressure of 200 bar (3000 psi). Source: PGS.

Table 1. Ramform Titan specifications

Length	104.2 m
Breadth	70 m
Draft	6.4 m
Fuel capacity	6000 m ³
Endurance (production/transit)	150 days
Transit speed	16 knots
Streamer winches	24 x 12 000 m capacity

microphones measure the reflected sound waves or blast waves and provide a detailed insight of the geological structure. The result of the seismic data acquisition can be depicted with a 2D or 3D image of the sea floor. The process is not only considerably safer for the staff, but also keeps the environmental images lower. However, it ought not be denied that the use of seismic sources can be disturbing or damaging to marine organisms, and under certain circumstances even lethal.

In support of the environment

This is why Petroleum Geo Services (PGS) has written an environmental declaration. The Norwegian company offers a wide range of seismic services and products for the crude oil industry. These also include seismic studies and analyses, data recording and data processing.

The declaration explains environmental management across the group according to the international management standard ISO 14001. The company, with its headquarters in Oslo and subsidiaries in more than 30 countries, is committed to the continuous improvement of the environmental compatibility of the seismic vessels. It measures, monitors and evaluates the worldwide applications in order to minimise the environmental risks and simultaneously to increase the efficiency of the exploratory activities.

Just by monitoring and observing the marine fauna, due to safety zones and restricted areas as well as appropriate time and weather windows, it has been possible to reduce the negative influence considerably. Above all, the so-called 'soft start' process has proven to be highly successful. The output of the air source is only increased gradually in order to provide the animals the opportunity to leave the sound source in good time.

The Norwegian company invests in new technologies such as the optimised fuel consumption of the seismic vessels for example. The revised design of the drive for the Ramform S Class has a higher effectiveness than the predecessor class, increasing its lifetime by 25% and its production capacity by 60%. The PGS Computer Center in London has received several awards for its low-energy concept.

In the latest project, two new vessels in the Ramform Titan series are equipped with NEUMAN & ESSER BLUESAPS systems, which are, at present, the cleanest solution for providing the air guns with compressed air.

Seismic Air Power System (SAPS)

The compressor manufacturer NEUMAN & ESSER (NEA) offers a comprehensive product range of high-pressure compressors as energy source for air gun systems. The NEA seismic air power system (NEA SAPS) can either be equipped with electrical or diesel drives and can be installed both on and below the deck. The compact systems are cooled by a closed cooling water system. Plate heat exchangers transfer the heat from the cooling water circuit into the seawater.

NEA SAPS combines a screw compressor with a reciprocating compressor. The screw compressor compresses the air from atmospheric pressure to approximately 15 bar; the reciprocating compressor compresses the air to the desired discharge pressure for seismic applications.

The system range incorporates eight construction sizes with an electrical drive and six construction sizes with a diesel engine drive. The smallest system provides 20 m³/min (700 ft³/m); the highest capacity so far is around 78 m³/min (2700 ft³/m). The higher the capacity, the shorter the possible intervals for shooting with the air guns. This provides more precise data and saves time.

A new development

Some 50 lubricated NEA SAPS systems serve as the energy source for air guns on seismic vessels on all the world's seven oceans. The newly

developed BLUESAPS, which is used for the Titan series by PGS, is the oil-free variant of the SAPS. The special feature of these units is that they provide clean air up to a pressure of 200 bar (3000 psi) with a two-stage oil-free screw compressor and a three-stage oil-free reciprocating compressor.

The compressor is designed to avoid oil entering the compression chamber and therefore contaminating the compressed air. Per 1000 operating hours, this variant saves up to 450 litres of oil and 110 m³ oil-contaminated condensate, which would have to be stored and disposed of expensively if lubricated compressors were used. Top manufacturing and production precision of the oil-free compressors helps ensure optimum efficiency.

Both the lubricated NEA SAPS systems and the BLUESAPS are water-cooled and equipped either with a water-cooled e-motor or a diesel engine. Without the oil trap for the lubricated screw compressor, the oil-free SAPS system is even smaller than the traditional variant.

One of the largest suppliers of seismic vessels had requested an oil-free version. This version of the SAPS systems is well in line with the NEA BLUE concept, which focuses on resource saving compressors. Subsequent market analysis in the seismic area has shown a clear tendency for oil-free compressors. Thus, the oil-free BLUESAPS concept was developed, utilising offshore and seismic experience.

The awkward separation and storage of the oil-containing condensate is no longer required with BLUESAPS. In addition to the ecological aspect, the lubricating oil savings are an important argument from an economic view. In order to avoid corrosion in humid and saline environments, all parts of this oil-free compressor system that come into contact with air are made of stainless steel. In case of longer idle periods for the seismic vessels, for example during transportation, the oil-free BLUESAPS systems are purged with the nitrogen on board and conserved with closed valves, again with nitrogen.

New investments

In 2011 PGS ordered two new generation Ramforms from Mitsubishi Heavy Industries Ltd. (MHI) one of the world's largest shipbuilders, which produces specialised commercial vessels. Delivery of the vessels is scheduled for 2013.

Two additional vessels will be numbers three and four in the Ramform Titan Class; planned delivery is 2015. PGS is to equip the two latest seismic vessels with a total of six BLUESAPS systems from the 62 series. The decision regarding the renewal and extension of the fleet comes at a time when the demand for seismic services is increasing.

After the market for seismic offshore survey regained momentum following a quiet phase since 2011, other suppliers also started to increase their investments in new equipment. The reason: according to the Seismic Offshore Report 2012, the demand for offshore surveys is increasing rapidly, by 10 - 20% in the past two years and in the coming year. However, the number of seismic vessels will only increase by 5% during the same period, as the study explains.

The increased demand is due on the one hand from the higher deepsea oil requirements as the improved drilling technology can advance to greater depths. On the other hand, the more precise measurement devices also discover deeper oilfields. This more efficient measurement technology is now used to re-explore fields. In this way, one of Norway's largest fields was recently discovered in an area that was considered to already have been fully exploited.

The Ramform Titan Series has developed success factors such as large spreads, long streamers and towing efficiency. These factors make that little, decisive difference in geologically complex areas such as Brazil, West Africa and the Gulf of Mexico. In areas that have been exploited as far as possible, such as the North Sea, the higher data precision reveals the new geological opportunities mentioned. ■



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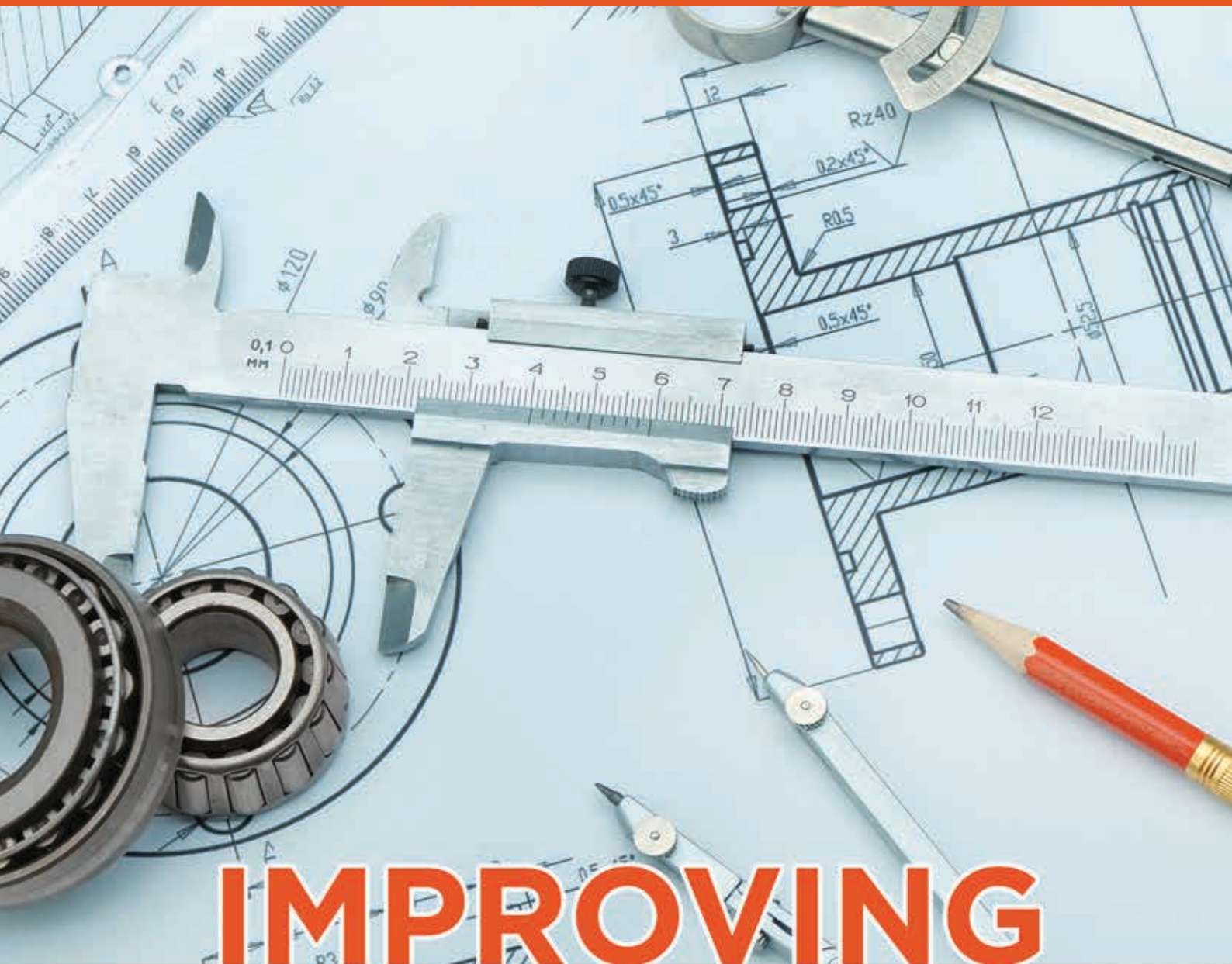
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Roger L. Schultz, TTS Drilling Solutions, USA, explains how many casing installation issues in horizontal wells can be solved via the use of expendable downhole vibratory tools.



IMPROVING INSTALLATION

Horizontal well construction continues to dominate the landscape. The horizontal sections of these wells have continued to get longer and longer as equipment and methods used in constructing these wells have improved. As lateral lengths have increased, so have the challenges associated with running casing and achieving good cement integrity. The primary issue seen while running casing is the high friction associated with horizontal well profiles and the absence of adequate vertical pipe weight to help overcome frictional forces. The high friction often requires the operator to apply excessive torque and force to the casing string and other completion components. Damage to casing

and completion equipment, such as frac sleeves and swellable packers, commonly occurs.

A second issue that often occurs in horizontal wells is lack of cement integrity. Channelling of cement and poor cement/casing bond is common in both the horizontal portion of the intermediate casing in the curve and in the lateral liner/casing.

Operators are increasingly running downhole vibratory tools to reduce damage to casing/completion hardware and to improve cement integrity. Vibratory tools help to overcome friction, greatly reducing the torque and force required to install casing therefore minimising potential damage to casing, frac sleeves, packers, etc. Cement integrity

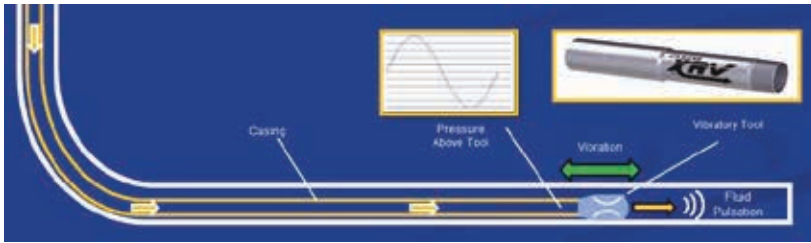


Figure 1. Operation of a flow interrupting vibratory casing tool.

There are now many configurations available for using vibratory tools during casing installation. These include tools run at the end of casing, multiple drillable tools run at various positions within the casing string, landable tools that can be run into casing from the surface, as well as other configurations. In this article an overview of the operating methodology and effectiveness of these tools will be discussed. Case study information showing the effectiveness of this technology will be presented.

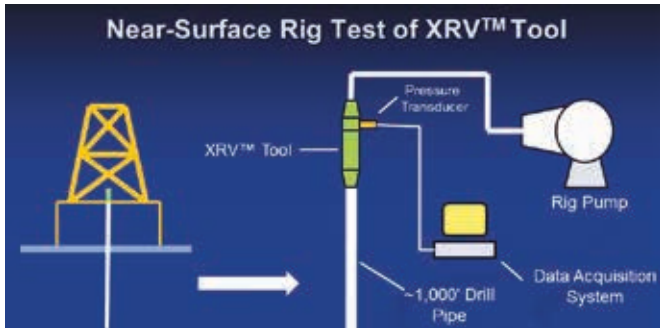


Figure 2. Test configuration for vibratory casing tool.

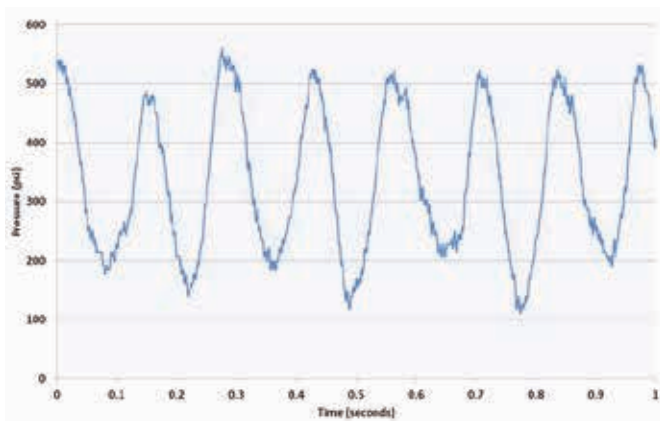


Figure 3. Pressure drop for 5.5 in. vibratory casing tool rig test.

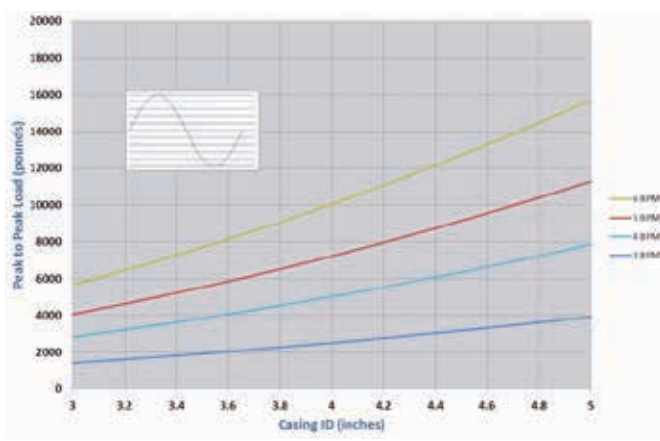


Figure 4. Vibratory load produced by XRV™ casing vibratory tool at various flow rates.

is improved by the casing vibration produced when cement is pumped through the vibratory tool. Drillable tools are available so they can be run anywhere in the casing string. These tools are typically one-use, expendable tools that are included in the casing string and are either drilled out, or remain in the well with the casing string.

Casing friction issues

The ratio of lateral length to vertical well depth has continually increased. The lack of vertical well depth compared to horizontal depth means that there is a reduced amount of weight available to push the casing out into the horizontal section as compared to the length of pipe creating frictional contact with the wellbore. Additionally, the casing friction in the horizontal section is higher than in a typical vertical section because the casing string, as well as friction causing debris is lying on the bottom of the hole due to gravity. The casing string is relatively stiff and has low clearance within the wellbore. This situation causes any deviation in the wellbore to create additional friction due to forced contact between the casing string and the borehole. Once the friction gets high enough to impede the advancement of casing into the well, rough handling of the casing is often necessary to get the casing to bottom. In these situations casing is often handled very roughly. It is not uncommon for casing to be ‘hammered’ into the well using the blocks on the rig. Rotating the casing helps to break the static friction, which aids in getting the casing to move. Rotation sometimes results in over-torqued casing. Over-torquing connections causes rolling of the pin threads into the ID, resulting in an effectively reduced ID and high wear and friction when workstrings are later run into the cased wellbore. When sleeve systems are deployed in the casing string, these components can easily be damaged, or have sleeves prematurely shifted while being run into the well on casing string that is handled with excessive roughness. Often the casing is left in an extremely high stress state, which causes issues later on in the life of the well.

High friction also greatly slows the speed with which casing can be run, thus having a direct impact on operational costs.

The problems caused by excessive friction in horizontal wells include:

- ▶ Failure to get casing to bottom.
- ▶ Excessive time spent running casing.
- ▶ High residual stress left in casing and other downhole components.
- ▶ Damage to casing due to rough handling during trip in.
- ▶ Over-torqued connections during rotation to get casing in hole.
- ▶ Damaged sleeve systems due to rough handling.

How do downhole vibratory casing tools work?

Reliable expendable vibratory casing tool technology has recently become available. This tool is a flow-interrupting tool that modulates the flow of fluid through the tool. This type of tool utilizes a ‘valve’ function in which the flow restriction through the tool varies with time. This periodic change in flow restriction causes oscillating backpressure across the tool as fluid is pumped through it. As a column of fluid travels through the workstring it encounters this changing flow restriction. When the flow is interrupted by the vibratory tool, the pressure above the tool increases due to both the water hammer effect as the fluid column decelerates and the continued flow of fluid into the workstring by the positive displacement surface pumps. This increased pressure acts across the hydraulic area of the workstring causing the workstring to elongate,

resulting in downward movement of the workstring at the tool. When the flow restriction across the tool then decreases, fluid pressure above the tool is relieved and the workstring contracts to its original length. This process repeats itself over and over as fluid flows through the tool causing vibration of the workstring.

Additionally, as the tool modulates the flow through it, fluid pulsation is created at the exit of the tool. This means that as mud or cement is pumped through the tool, there is pulsating flow exiting and flowing around the casing shoe. This fluid pulsation tends to break fluid channelling and create uniform flow up the outside of the casing. The vibration of the casing string and fluid pulsation during cementing operations helps to ensure a high quality cement job by reducing voids and channelling, much like vibratory tools used in the construction industry, which ensure high quality concrete with no holes or voids. Vibratory tools for casing can be made drillable, so they are much like any other piece of floating equipment in terms of flexibility of future well operations.

The operation of a flow interrupting vibratory casing tool is depicted in Figure 1.

Fluidic flow-modulating vibratory casing tool

This is a relatively new type of flow interrupting vibratory tool technology that has been used extensively in coiled tubing and drilling operations and more recently in casing installation applications. The tool utilises a specialised flow path to create a varying flow resistance, which acts much like an opening and closing valve without having any moving parts or elastomeric components. The 'valve' function is created using fluidic elements coupled together to create a self-induced, oscillating change in pressure above the tool.

Characteristics of fluidic flow modulating tool:

- ▶ No moving parts - highly reliable.
- ▶ No elastomers - no issues with fluids, chemicals or gases.
- ▶ No temperature limitation.
- ▶ Very short and rugged.
- ▶ Drillable.

This technology is uniquely suited for the casing application. The simple, no moving parts design makes it possible to make a tool that is very effective, but inexpensive enough to manufacture that it can be used as an expendable tool that is left in the well.

Test data for casing vibratory tool

Figure 2 shows a field test setup in which casing XRV™ data was recorded. An XRV tool was suspended from a drilling rig and the rig pumps were used to circulate fluid through the tool. The internal components of the tool tested are typical for 4.5 in. and 5.5 in. casing tools. A high-speed data acquisition system was used to record the resulting pressure drop across the tool. Figure 3 shows the recorded data. This data shows a 300 - 400 psi peak-to-peak oscillating pressure change across the tool at a 160 gpm flow rate.

If the flowrate through the vibratory tool is increased, the peak-to-peak pressure drop across the tool also increases. The vibratory load generated during the operation of a casing XRV tool can be computed by multiplying the peak-to-peak pressure drop shown in Figure 3 by the hydraulic cross-section (internal area) of the casing string. Figure 4 shows the resulting vibratory load for various pump rates as a function of casing ID.

It can be seen by examining Figure 4 that the vibratory force imparted to the casing can be very high if desired, even with a moderately low average pressure drop across the vibratory tools. In other words, very significant vibratory forces can be imparted to the casing string with only a small increase in circulating pressure.

Case studies involving vibratory casing tools

Case study #1

Details:

Formation: Woodford Shale

Location: Central Oklahoma

Tools used: 5.5 in. casing XRV™

Fluid: 9.25 ppg water based w/ 56 viscosity

Pump rate: 250 - 420 gpm (0.9 - 1.6 m³/min)

Drill pipe: 5.5 in. casing

Lateral length: 5500 ft (1676 m)

Total depth: 11 550 ft (3520 m)

Days in use: 2 days

Results:

The customer wanted to compare the casing installation of two wells, spaced one mile apart; particularly focusing on the overall time taken to run the casing in hole as well as any difficulties or force needed to push the casing to bottom. A vibratory casing tool was used on the first well where the casing was installed to TD and the cement job was completed in a total of 36 hours. The casing installation and cementing of the second well, without using a vibratory casing tool took a total of 54 hours to complete. It took 33% less time to run the casing on the job where the vibratory casing tool was used.

Case study #2

Details:

Formation: Niobrara Shale

Location: Wyoming

Tools used: 5.5 in. casing XRV™

Fluid: 9.1 ppg water based w/ 56 viscosity

Pump rate: 250 - 325 gpm (0.9 - 1.23 m³/min)

Drill pipe: 5.5 in. casing

Lateral length: 6000 ft (1829m)

Total depth: 12 333 ft (3759m)

Days in use: 1 day

Results:

A customer in the Niobrara Shale formation continuously had problems running casing to bottom; a previous well had taken upwards of 17 hours for the final 3000 ft (914 m) to reach bottom. The customer was looking for a viable solution to decrease run time and minimise force needed to install casing. After implementing a vibratory casing tool, the customer was able to successfully run 12 333 ft (3759 m) of casing to bottom in a total of 12 hours without any issues.

Conclusion

In order to combat the negative effects of friction, the industry has embraced downhole vibratory tool technologies. New drillable, low-cost, expendable vibratory casing tools are now being used to resolve friction related issues that operators often experience when running casing, frac sleeves and swellable packers.

This technology allows casing strings, sleeves, swell packers, etc. to be run faster, with minimal force and torque required, greatly reducing the risk of damage while reducing installation costs by saving time. Additionally, the vibrating action produced by these tools during the cement job helps to improve cement bond and integrity. ■

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SOLVING SHALLOW SITUATIONS

Jerry Fritsch, Stacey Andrews and Roy Baker, Enventure Global Technology, explore the opportunities for solving shallow drilling problems through the increasing use of solid expandable liners.

At the time of writing, more than 6000 ft of 16 in. solid expandable tubular (SET) liner has been installed in four commercial applications. Each use has added significant value to the wellbore construction process by solving common upper hole problems such as shallow gas, unstable formations and high-pressure fluid flows.

These problems have existed for many years without any other solution than conventional tubulars, which by their nature begin a problematic sequence of smaller internal diameters that continues for the rest of the wellbore construction process.

The use of larger diameter expandable tubulars higher in the hole provides the opportunity to conserve hole size deeper in the well and ultimately optimise the completion. Conventional industry wisdom has long recognised that the maximum value of a solid expandable liner is realised when it is run as high in the wellbore as possible. The application of this understanding has been limited by the maximum diameter of expandable pipe.

Development of 16 in. SET is a significant increase from the previous maximum of 13 3/4 in. diameter. Historically, 13 3/4 in. SET has provided a solution in the intermediate to lower section of a wellbore where the majority of expandables sizes have been utilised. Due to its diameter, the 13 3/4 in. could not provide an upper hole solution. As operational and



economic conditions have become more challenging, operators have requested a large diameter expandable to handle with up-hole issues. With a 16 in. SET in the inventory, operators can extend the shoe of 18 3/8 in. and 20 in. casing to enable hole size preservation in early stages of the wellbore construction.

Technology development

Large diameter 16 in. SET is a significant advance in a technology that was first used approximately 14 years ago and today accounts for more than 1450 installations or 382 km of expandable liner of all sizes – enough to reach from Dubai to the International Space Station.

SET technology has been viewed primarily as a contingency application employed when conventional casing is unable to reach the target depth. In contrast, larger diameter, top-hole SET is a planned component of the well design. Run in the upper wellbore, SET creates new design opportunities for preserving wellbore diameter deeper in the hole, in contrast with contingency efforts to save hole size. This paradigm of opportunity versus need (Figure 1) becomes a viable option with the ability to begin wellbore ID optimisation early in the well construction cycle.

Planning considerations

One of the key advantages in running SET higher in the wellbore is enabling the use of conventional liners to deal with greater challenges deeper in the wellbore.

Overall wellbore geological and mechanical complexity is typically reduced in the upper sections of the wellbore. Wellbore temperatures are considerably lower, even in double digits, compared to the 400 ° F (204 ° C) temperatures in the lower sections of a wellbore. Mud weights are typically managed to be as low as possible in upper wellbore sections, in contrast to the 20 ppg systems used in deeper sections.

These variables affect SET planning considerations for upper hole applications versus smaller diameter contingency roles (Figure 2). From a drilling standpoint, directional work is often implemented deeper in



Figure 1. Large diameter SET shifts the use paradigm from need to opportunity.

Planned / Contingency	SET Sizes	Pressure to Expand	SET Wall Thickness	Mud Weights	Temperature	Depth Complexity
Planned	16 x 18-5/8, 20 13-3/8 x 16 11-3/4 x 13-3/8, 14 9-5/8 x 11-3/4 8-5/8 x 10-3/4 7-5/8 x 9-5/8	Lower	Greater	Lower	Lower	Lower
Contingency	6 x 7-5/8 5-1/2 x 7 4-1/4 x 5-1/2	Higher	Lesser	Higher	Higher	Higher

Figure 2. Top-hole SET presents different installation considerations. Installation typically takes place in a lower risk environment.

the wellbore, so BHAs and ECDs are typically much simpler in the upper wellbore. From an expandable system perspective, the same is true in that larger expandables are more robust (having a thicker wall). The pressure required for expansion also decreases as expandable tubular size increases, which simplifies installation in the upper wellbore.

In a large diameter, top-hole SET installation, these factors help maximise the ability of expandables to ensure the well is drilled and completed as designed. The result is significant. Instead of restricted production from a wellbore that is smaller than designed, expandables used higher in the hole can make a significant contribution to optimising production over the life of the well.

16 in. solid expandable tubular applications

The various problems encountered in the top-hole section of a well often include:

- ▶ Unstable formations.
- ▶ High-pressure water flows.
- ▶ Depleted zones.

These challenges typically result in surface casing being set shallower than designed, which has the effect of putting the drilling programme behind from the start. Overcoming them required a way to extend the 20 in. or 18 3/8 in. surface casing with minimal ID loss. The development of 16 in. SET mitigates top-hole risks by putting them behind a robust steel barrier that allows drilling to continue with minimal loss of ID.

A 16 in. SET system also builds contingency options into the well design by providing an extra casing shoe in the relatively benign top-hole section of the wellbore. This enables the use of standard casing or liner systems in trouble zones deeper in the wellbore where higher differential pressures can preclude the use of a SET liner system.

One of the most important capabilities of a 16 in. SET system is the ability to achieve a post-expansion API-standard hole size. This effectively eliminates the need to underream the hole section below the expandable to run and cement the next conventional casing string.

Uthmaniyah field

Field conditions and challenges

Drilling gas wells in the Uthmaniyah field is complicated by the need to drill through the shallower oil-producing Arab-D formation to reach to the deeper, gas-producing Khuff and Unayzah formations. The challenge is to drill through the Arab-D without disturbing reservoir properties, which could negatively affect production rates of nearby oil producers or future wells.

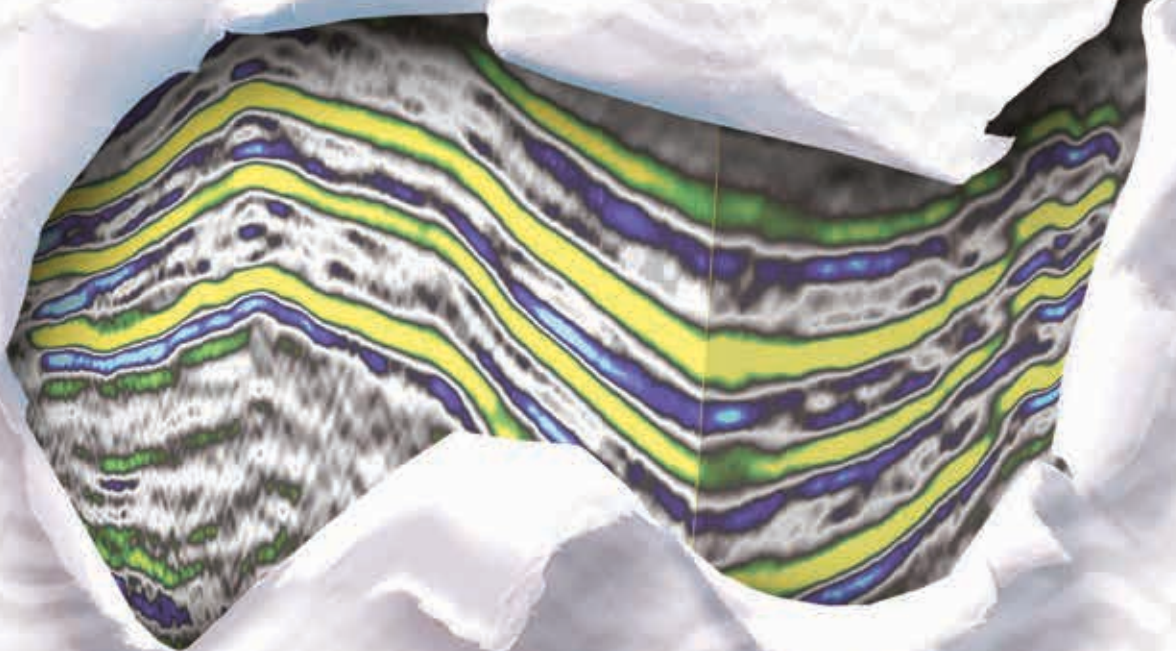
Additional challenges in the Uthmaniyah field are isolated shallow gas pockets and deeper, high-pressure zones in the Base Jil dolomite (BJD). Both scenarios can require setting the casing to isolate the troubled zone, which can adversely affect the completion size and design for the remainder of the well.

In the past, a K2 well design was developed to mitigate all the scenarios. The design enables a single Khuff lateral well to be drilled while allowing for a contingency casing point below the BJD, which ensures the well results in an acceptable lateral. The K2 design achieves what is considered the largest feasible starting casing diameter for the rig and casing capabilities (Figure 3).

In this K2 design, the plan is to set the 13 3/8 in. casing at the BJD, which allows for the loss of a casing point below BJD and still permit a 5 7/8 in. lateral to be

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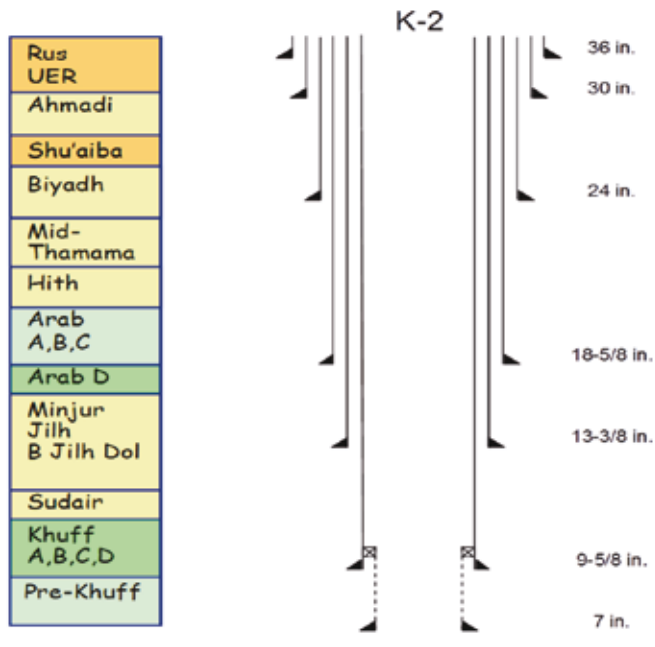


Figure 3. Original K2 well design.

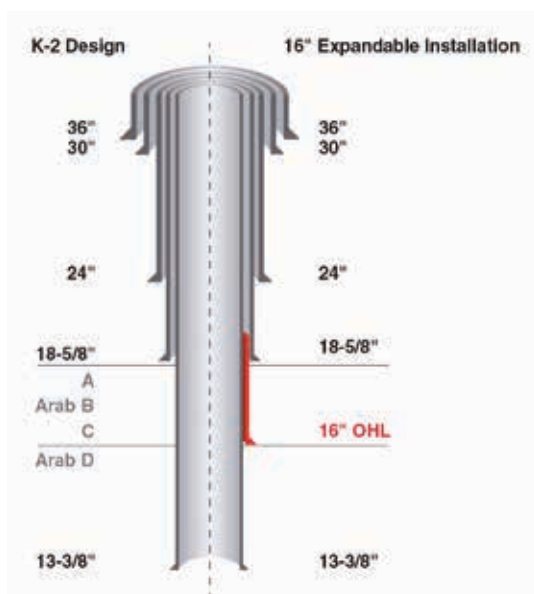


Figure 4. K2 wellbore and design with 16 in. expandable.

drilled in the Khuff or Unayzah reservoirs. More recently, changes in shallow gas drilling procedures have resulted in the loss of a casing point in the K2 design. When drilling into the upper portions of the Rus formation, isolated shallow gas pockets can be present. Following the Macondo well incident in the Gulf of Mexico, the practice of bleeding the gas pocket before nipping down the 30 in. diverter to run 30 in. casing was eliminated. Current regulations state that casing must be run prior to nipping down the diverter. This requirement resulted in the loss of the 30 in. casing point and required running the 24 in. casing at the shallower setting point in areas where gas is encountered.

Additionally, the pressure regimes in the Arab-C and -D are not constant across the field. In some circumstances, mud systems can be effectively used to mitigate the pressure differentials, but other situations require casing to be set.

Confronted with all of these potential casing loss points, the K2 design is effective in mitigating the loss of only two. If all three scenarios occur, the well cannot be delivered as a lateral producer pursuant to the plan. In this case, a 4 1/2 in. liner will be set vertically through the targeted reservoir

and a hydraulic fracturing treatment will be performed before the well is put in production. A coil-tubing unit (CTU) may be brought onto the well to complete the smaller 3 7/8 in. lateral.

Expandables selection

When examining wellbore design options, it was realised that there would be benefits in using a larger diameter SET system higher in the hole. The benefits included easier underreaming because shallower rocks are typically not as difficult to drill as deeper lithologies. These benefits are balanced by the larger hole size and the removal of a greater volume of rock. In addition, pore pressures are lower and the required liner yield and collapse are usually less. Also, planning a shallower expandable creates the opportunity to use conventional liners in the more difficult, deeper sections of the hole.

Meeting a need

The development of a large diameter expandable was initiated as a solution for the various problems associated with drilling shallower sections of the wellbore. A 16 in. liner was selected as it extends the 18 5/8 in. casing and 20 in. casing commonly used in casing designs (Figure 4).

The large diameter expandable can also slim the overall design by pushing a section deeper, and it can save a conventional liner or casing size for more difficult areas deeper in the wellbore.

Job objectives

The Uthmaniyah field application had a number of objectives. They included providing a robust extension to the 18 5/8 in. casing string to prevent the loss of a casing point due to isolated shallow gas pockets, and avoid the loss of a casing point due to pore pressure differences between the Arab-C and Arab-D. It was also important to provide a standard API post-expansion drift ID, which eliminated the need to under-ream below the expandable liner and allowed the existing 16 in. drilling assemblies to be utilised to drill the section following the expandable liner.

Results

In the first field application of the Enventure 16 in. x 18 5/8 in. SET, the OHL system successfully isolated the normally pressured Arab-C formation, allowing the Arab-D to be drilled with a special, lower-weight mud system. This mitigated fluid losses while drilling the Arab-D and cross flow between the different reservoirs. A 16 in. post-expansion pass through allowed the operator to drill out with a standard 16 in. bit size.

The successful 16 in. SET liner installation proved the system's ability to provide a cost-effective means of maintaining the K2 well design in the event a casing point is lost. In doing so, the application met the operator's goals. Installation of the system between the Arab-C and Arab-D formations has saved approximately two weeks of rig time. In addition, it has reduced costs from mud losses and cement plugs required to drill through the lower pore-pressure of the formations below Arab-C and reach the target casing point at the BJD.

Conclusions

In Saudi Arabia's Uthmaniyah field, Saudi Aramco has improved wellbore construction operations by extending the number of casing points available with its K2 well design. The additional casing points were achieved with the industry's first installation of large diameter, 16 in. SET for use in upper hole sections. The Enventure SET open hole liner installation has helped cut rig time, reduce costs and optimise drilling operations.

The introduction of a 16 in. solid expandable tubular is a significant advance in the scope of SET applications. With a large diameter expandable pipe suitable for upper hole use, well designers have a new tool for preserving wellbore diameter early in the planning process. ■

THE IMPORTANCE OF ACTIVE ADDITIVES

David L. Holcomb, Ph.D.,
CESI Chemical, a Flotek Industries
Company, USA, runs us through
the optimisation of surface active
additives used in unconventional
reservoir stimulation treatments
and reveals their impact on
reservoir performance.

In order to explain the importance of surface active additives, this article seeks to answer several questions. The questions include the following: What are surface active additives? What do they do? Do unconventional reservoirs need them? Which are best? How do companies choose the right surface active additives for UCRs? How is additive performance measured and justified? And are there other, more efficient forms of surface active additives?

What are surface active chemicals?

Surface active additives are molecules formed of two parts with different affinities for solvents, (hydrocarbon or water). One part for aqueous (polar) solvents and the other for hydrocarbon (non-polar) solvents.

A small quantity of surfactant molecules rests upon the water/air or water/oil interface and decreases the surface tension (force per unit area) needed to make available surface.

There are also more efficient and effective surface active additives, known as microemulsions or complex nanofluids (CnF®). A microemulsion or nanofluid is a thermodynamically stable, translucent-to-transparent micellar solution of oil



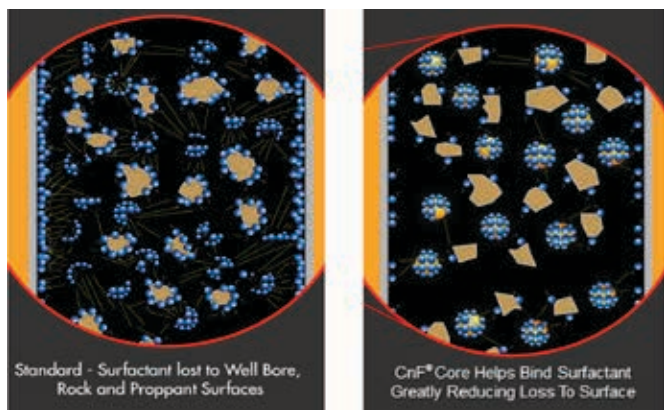
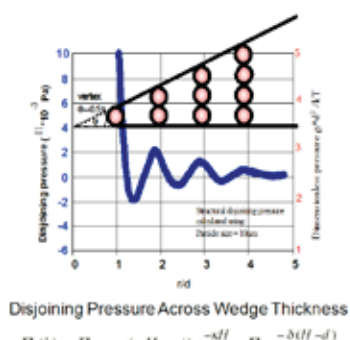


Figure 1. Adsorption - surfactant versus Cnf additive.

◆ Disjoining Pressure

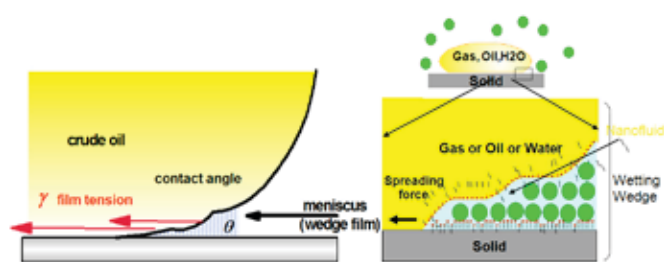
- **Lifting Force Concentrated at the Wedge Vertex**
 - ▶ This force overwhelms discontinuous phase absorption forces
- **Nanofluids Catalyze Discontinuous Phase Release from Surface**
- **This Affects Water-Wetting Surface after Release**
- **From: Wasan & Nikolov; Nature, Vol. 423, 2003.**



Disjoining Pressure Across Wedge Thickness

$$\Pi(h) = \Pi_0 \cos(\alpha h + \phi) e^{-\beta h} + \Pi_1 e^{-\delta(h-d)}$$

Figure 2. Advanced nanofluid behaviour.



Modified From Wasan and Nikolov; Nature, Vol. 423, 2003.

Figure 3. The wedge effect.

and water that may contain electrolytes, and one or more amphiphilic compounds forming droplet/particle sizes between 5.0 and 100.0 nanometres. They are able to provide ultralow interfacial tensions.

What do surface active additives do for oil and/or gas reservoirs?

They prevent emulsions with reservoir liquid hydrocarbons and solids. They lower surface energy and interfacial tension between reservoir rock/wetting phase(s) and treating fluids for more efficient oil and/or gas recovery. Finally they lower surface tension between treating fluids and produced fluids for improved load recovery.

There is something else about many conventional surface active additives, albeit negative in nature. They can create foams within proppant packs, and adjacent porous/fractured media due to pressure drop from stimulation fluid flow-back, short-term

or prolonged shut-in and/or production thereby blocking recovery.¹

Do unconventional reservoirs need surface active additives?

‘Not really’, If: there are no capillary imbibition effects from well intervention fluids. However, these effects are always present, especially in natural fractures, induced secondary fractures and smaller size (40 - 70 and 70 - 140 mesh) proppant packs, or even a ‘reasonable’ permeability matrix (millidarcy-microdarcy).

Do UCRs need ‘conventional’ surfactants?

Conventional surfactants are not necessarily needed for UCRs, as they can foam too much and cause too much ‘uncontrolled’ leak-off and subsequently induced negative imbibition effects, i.e., they do not typically lower interfacial tension as significantly as needed, and as such, they do not reduce capillary imbibition effects either and thus neither load recoveries nor hydrocarbon productivities are as high as anticipated. As such, some say they do not work. In other words: surface tension reduction alone is not always the answer! See Figure 1 for a comparison showing surfactant adsorption versus greatly reduced adsorption from CnF nanofluid.

Which surface active additives are best for UCRs?

Other novel technologies can be selected that employ surface chemistry in combination with other more dynamic characteristics, such as microemulsions or nanofluids containing various terpene solvent fractions plus surface active additives; and co-solvents such as alcohols. Also, nanoparticle dispersions, and/or CO₂ will work even more effectively in concert with microemulsions. In combinations or individually they may be used in smaller more concentrated pre-pads ahead of successive fracturing stages in order to maximise entry into secondary fracture networks where proppants often fail to go.

The mechanism of disjoining pressure is another mechanism where microemulsion nanodroplets (CnF) are driven by Brownian motion to further enhance the already low interfacial tension and internal solvent (terpene) phase to mobilise even more hydrocarbons through fractures, proppant or reservoir porous media (Figures 2 and 3). This mechanism serves to further differentiate nanofluids/microemulsions or micellar solutions from ordinary surfactants.

What are the criteria for the ‘best’ surface active additives chosen for UCRs?

Now, it becomes readily evident that: optimum surface active additive selection dictates performance requirements, using the following mantra used in the past by major corporations whose clients want all technology to be:

- ▶ Good = highest quality for required application.
- ▶ Fast = expediently available/functional when required.
- ▶ Cheap = cost-effective with respect to value added.

However, industry practices today usually allow only two of the above. Why is it difficult to realise all three? Because commitment is required.

Justifying and measuring surface chemistry performance for this new application demands a return to the lab for rigorous testing and timely field trials with some new solutions: Nanofluids as chemical pre-stimulation or natural or induced secondary fractures in UCRs. Once done as with normal use of complex nanofluids (CnF) as illustrated in Figure 4. This illustrates the net



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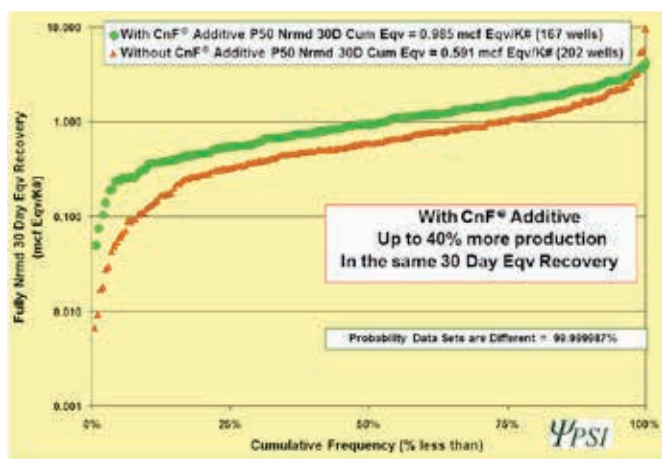


Figure 4. 30 day normed recovery; Rocky Mountain Basins.

impact on productivity as compared to non-CnF treatments on jobs done throughout the basins of the Rocky Mountain region, USA.

Just ask, “Do the choices fit that ‘Good-Fast-Cheap; Pick Any Two’ scenario?” Are they selected based on: the quality of results, expedient and long-term performance evaluation, or added value with cost-effectiveness? (Remember: price and performance determine effective cost.)

Is surface active additive selection, art or science?

Additives are substances that perform useful functions to enhance or protect the process being applied. In stimulation operations such as acidising, acid fracturing or fracturing, additives are chosen that will function to control, support, or change the ultimate beneficial effects of the well stimulation effort. The answer is a bit of both, that is, science usually dictates the ideal additive selection and art follows the path of least cost, assuming that selecting something is better than nothing at all, even if it is wrong for the particular application at hand.

Criteria for stimulation additive selection

With reservoir rock and fluids, reservoir intervention fluids and wetting phases associated with multi-wet scenarios usually prevail (Radke; U.C. Berkley) with other conditions necessary for treatment performance within the reservoir environment i.e., temperature, pressure, rock mechanics, geology, geochemistry. This all must be in concert with consideration for the environment. CnF and microemulsion technology are more environmentally friendly than most conventional surfactant technologies in use today.

Ordinary surfactant functionality must be considered when treating various reservoir environments as well as fluid compatibility issues with all common surfactants in a variety of fluids, such as: fresh water, produced water, synthetic brines, etc. For example, ordinary cationic surfactants are used for the dispersion of clays and/or fines in oil phases, and they oil wet limestones and dolomites at pH greater than 9.5. They can emulsify aqueous phases in oil. They tend to oil wet sandstones, shales and clays. They are used to break oil in water emulsions. They water wet limestone or dolomites at pH up to 8.0. Finally cationic surface active agents provide excellent corrosion inhibition as well as very low surface tensions (i.e., fluorosurfactants).

Anionic surfactants provide a number of useful functions including the water wetting of sandstones, shales and clays. They will disperse clays or fines in the aqueous phase.

They water wet limestone at pH levels above 9.5 and are useful in breaking water in oil emulsions. On the other hand they will emulsify oil in water.

Amphoteric surfactants act as effective corrosion inhibitors for several applications and can provide excellent foaming performance and compatibility with brines. They contain both acid and basic groups on their molecules, which provides flexible performance in a variety of changing environments.

Nonionic surfactants are extremely popular for use in oil and gas operations as they provide compatible agents to address the enhanced water wetting in sandstone reservoirs while providing excellent non-emulsifier characteristics. As aqueous foaming agents they provide non-damaging solutions in porous media. Another application is their ability to act as a flocculating agent when required. Finally their penetrating ability reigns supreme among ionic surfactants due to their less or non-adsorptive tendency in most environments.

It is important to note that the consequences of incorrect surfactant additive selection or incompatibilities with other well stimulation additives can lead to a number of problems including, but not limited to, the following: excessive fluid loss, confined imbibition, increased friction while pumping, increased corrosion rates, reservoir incompatibility, emulsion blocks, acids dissolving either too fast or too slow, fines release and or suspension, relative permeability damage, wettability alteration, pore throat restriction and swelling/migration of fines and clays. Some of these items are advantageous in certain applications or disadvantageous in others, which is why care should be exercised when designing their use within a variety of applications.

Whereas the ionic character, that is so critical with conventional surfactants, dictates the need for their precise application, microemulsions/nanofluids are more flexible because they are uniquely ‘containerised’ for delivery and maintain their functional integrity as well as nano-structure throughout any type of treatment application, including all of the applications discussed previously with respect to common surfactants. Once applied, they target their specific actions with greater compatibility, thereby reducing or eliminating the chances for causing the long list of consequences in the previous paragraph.

Summary of surface active chemical additive selection parameters:

- ▶ Proper additives selection in stimulation is the key to optimum well performance.
- ▶ Reservoir characteristic changes require additive selection changes.
- ▶ Additive selection optimisation is easier than salvaging wells after inappropriate additive use.
- ▶ Surface energy effects (IFT + Brownian motion driven, disjoining pressure wedge to displace hydrocarbons (oil, paraffin, asphaltenes, sludge, etc.), are the key criteria for maximising reservoir Interaction with properly selected surface active chemistry such as highly efficient complex nanofluids.
- ▶ Diagnosis of treatment requirements is essential to additive selection process.
- ▶ Added value costs plus realised performance = multiple folds of production enhancement. ■

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KEEPING IT *flowing*

Kelvin Davies, AVEVA, UK, looks at how new technologies are helping to make upstream assets safer and more productive.

Offshore oil and gas production generates huge revenue streams, and keeping it flowing is a serious business. But production facilities are also complex, hazardous places in which to work; they are often in very challenging locations and are subject to stringent regulations, so safety and environmental criteria cannot be compromised. Fortunately, the principles of sound asset management serve both objectives; 'doing it right' embraces 'doing it safely' and it is no coincidence that those operators who invest most heavily in their engineering skills and processes are also those with the most productive and reliable assets.

Maximising uptime and working safely both demand trustworthy and accessible information. This is why operators who exploit today's Information Management technologies have transformed their





Figure 1. AVEVA Work Permit Manager screenshot showing Work Permits marked on a Plot Plan colour-coded by type.

asset management performance. IT tools have, of course, been used for this purpose for a long time; spreadsheets, database applications and email were quickly pressed into service. However, their limitations became apparent as assets and business processes became increasingly complex. Dedicated but flexible technology was required. An example of the powerful solutions now in use is AVEVA WorkMate™, an integrated Enterprise Asset Management (EAM) solution specifically developed for the needs of the offshore industry.

Offshore EAM covers a variety of distinct activities that all converge on one objective: maximising uptime. Each activity (materials provisioning, maintenance planning and so on) therefore needs software tools that support its specific needs while also being integrated to support the overall asset management objective. WorkMate is built as an integrated, modular solution. It comprises modules for maintenance, procurement, materials management and the management of technical information. These are supported by a range of individual web applications for specific tasks such as safe job analysis and work permit management.

The system in action

A typical example of the system in action: a maintenance manager on an offshore platform is planning the team's workload, which includes a work order for scheduled maintenance of a pump. As the maintenance manager compiles the necessary information, a requisition is raised in the system for the parts required, which include a new impeller. The system passes this requisition to the platform's materials controller, who finds that the impeller is not in stock, either on the platform or at the onshore depot. The controller then forwards the requisition to a procurement or purchasing officer who identifies that this is a standard part and uses the system to send a purchase order to the relevant supplier (the system can also handle non-standard procurement where an RFQ must first be issued to a number of approved suppliers).

The supplier uses the system's Order Manager™ application to communicate with the purchaser and call off the impeller against the supply contract and frame agreement. The application knows that the impeller must be sent to the client's onshore depot, while the invoice must go to the procurement office. The impeller arrives at the depot, where its receipt is registered. Here, WorkMate knows that a regular delivery to the platform is scheduled for the following day, so it routes the impeller to the despatch team for batching up with

the rest of the materials consignment. Throughout this process, the system has enabled the maintenance manager to monitor the progress of the impeller and to know when it will arrive and to which stores location it will be passed. The maintenance manager can then update the team's work schedule accordingly.

Meanwhile, the pump maintenance work order requires a safe job analysis (SJA). Happily, an SJA exists in the system from previous work, so time and effort can be saved by copying it to the new work order and checking to ensure that it remains valid, before approval by the platform's safety officer. Throughout the process, WorkMate has handled all the information flows in a single integrated environment. Clearly, this

process is more efficient than using individual applications for each activity.

The system is used by AMEC on Fairfield Energy's Dunlin A platform in the North Sea, where it plays an important role in well-planned and prepared shutdowns. Planning and preparation has moved into a new era. Everything is in one place: the task details, the resources and the calculation of the shutdown's duration. AMEC's maintenance team leader stated that with the system it was possible to find out which tasks were overrunning and were a threat to the work being closed out on time. Personnel are able to make sure that all safety-critical work is closed out on time, that HSE responsibilities are fulfilled and that the integrity of the platform is maintained.

New opportunities

The unique challenges faced by the offshore sector drive important technology developments that then go on to serve the downstream sector and other plant industries. The WorkMate system is one example of this, but another technology is now emerging that is likely to follow suit. This latest development is in the application of gaming technology to the much more serious business of operator training on complex engineering assets, such as offshore platforms or FPSOs.

Hands-on training is by far the most effective way to learn or practise any skill. But, as well as the high cost of training offshore personnel onsite, a serious limitation lies in the hazards involved, both to people and to the facility itself. Make a mistake and 'Game Over' really can mean just that. Gaming technology now overcomes this by enabling operations personnel, using entry-level computers, to engage with each other in complex scenarios in convincing 3D virtual worlds where virtual objects behave like their real world counterparts.

Imagine that, instead of interacting with a completely fictitious 3D environment, personnel could move around within an accurate model of a real offshore platform, in which valves turn, switches switch and a dropped hammer can fall on the head of a colleague's avatar climbing a ladder. But instead of causing a serious injury they will have only lost points on your competency score. This kind of capability has obvious value when it comes to training personnel. It is now available to the plant industries in the form of AVEVA Activity Visualisation Platform (AVEVA AVP™).

AVEVA AVP enables the creation of an accurate and interactive, immersive 3D model of a real facility, directly from its



Figure 2. AVEVA Activity Visualisation Platform enables learning through simulation.

3D design model. Immersive 3D is, of course, not new; it has been a powerful tool for design review for many years, but this software takes the concept a stage further. First, it creates a much more realistic environment than is necessary for design review. The model can be correctly oriented so that, as the virtual sun rises and sets, it creates accurate and realistic light and shade. Night scenes can be realistically illuminated by the luminaires, simulating the working conditions encountered on the real facility. This can reveal situations that a normal review model cannot; for example, an isolating switch may be hard to see at night.

Second, the software is a 'multi-player' application. A maintenance team can practise a procedure under realistic conditions without putting themselves, the facility or its production at risk. The software also enables movable objects such as barrels, ladders, buckets or even forklift trucks to be used in these procedures. If a team member clumsily drops a virtual barrel, virtual gravity makes it fall and roll in a realistic manner.

Third, necessary information can be summoned by using an in-game browser window. This can simulate the use of a mobile device to pull up a drawing or procedure for the task, or it can provide prompts or questions during training exercises.

Many important asset management tasks are infrequent, so a maintenance team may be out of practice in a given task. Now they can refresh their skill and rehearse the task to minimise downtime. Equally valuable, new employees being deployed to a platform can be familiarised and trained in advance, so that on arrival they can function safely and efficiently.

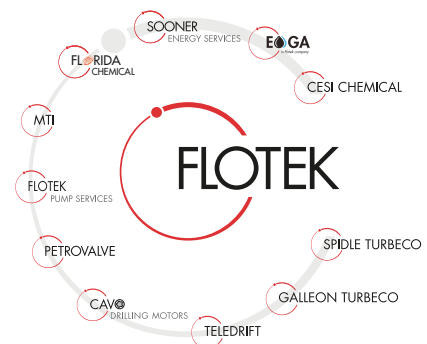
It is likely that industrial gaming will continue play an increasingly important role in asset management. Well-managed use could include the logging of individuals' training records, showing who has which competencies; information that could be made available to an EAM system and used in maintenance planning, for example.

The offshore industry has never been better served by technologies that can make its operations safer and more efficient. All stages of an asset's lifecycle benefit from accurate, easily accessible information for optimising construction, scheduling, maintenance and operations. ■

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UPGRADING *the classics*

Recent editorials regarding drilling operations safety¹ have stirred anew conversations about why a modern rig is considered safer and a better performing option.

The modern drilling rig (MDR) has the following performance and safety systems: (a) a fully automated pipe and casing handling system that delivers the tubular from storage to hole without direct human contact, (b) is easily moved both during site-to-site transport and on pad site well-to-well moves, (c) provides flexibility to adapt between different types of well drilling programmes based on the needs of the E&P company, (d) makes use of software interfaces to monitor and potentially control the drilling operations on the rig, (e) has a smaller foot print than comparable conventional rigs in the same class, and (f) employs qualified and trained technicians to maintain and operate the MDR.

Automated handling eliminates injuries

As of this year, the MDR does not require technicians to be in direct contact during the drilling process. For the 363 mT or smaller hook load capacity rig: (a) electronically controlled catwalks now deliver the pipe or casing from the rack storage, to the catwalk, up to the rig floor, (b) a top head (or drive) with a tilting system picks up the pipe or casing and lifts it into position, (c) then the pipe or casing is positioned for connection to the existing drill string that is hanging in the rig floor, (d) either a pipe handling connection tool or a combination of a make-up/break out

KELLY SHIDELER, SCHRAMM, INC.,
USA, LOOKS AT THE SYSTEMS THAT
CHARACTERISE A MODERN DRILLING
RIG AND COMPARES THEM TO THE
OLDER, CLASSIC DESIGNS.





Figure 1. Left: MDR fully automated with 26 m rig-floor-to-top-of-mast height and no men on the floor or at height. Right: Equivalent class advanced AC Drive with 41 m height from floor to top. Men are required to work at height and on the rig floor.

wrench is used to connect the newly positioned upper pipe to the existing drill string, (e) finally the drill string is freed from its secured position and begins drilling hole again. For the 363 mT or larger rig; there is usually a mast with monkey boards, where the drilling pipe may be racked, after initial first drill use, an automated arm will then manipulate the pipe into position for drilling operations. Today, there is no reason for a man to be working 'at height'.

What is important about this process is not necessarily the steps, but that there are no technicians touching the floor equipment or pipe during the process. Historically, a man would be in the mast, guiding these operations manually and on the floor making the connections with a pipe wrench, or a machine known as an 'Iron Roughneck'. On an MDR, these steps are controlled from the driller's control room by the driller and an assistant driller. MDRs look very different from even advanced AC drive rigs, which are prevalent in the drilling industry today (Figure 1).

For the operator, this means consistent and accurate completion of a repetitive task and lower risk of injuries. This translates to cost savings and the preservation of their reputation as a safe operating company. For the drilling contractor in the first class of rig described, it allows for a smaller rig to be built to accomplish the same drilling compared to conventional rigs. In the latter MDR described, it enables the contractor to remove the man from working at height in the mast or on the floor. Furthermore, automating the pipe handling system allows the contractor to consider new designs of rigs, which includes the possibility of a more mobile, agile drilling rig.

Modern mobile drilling rigs

The latest advances in materials, equipment footprint and engineering have changed the classic 'rig move' and improved safety. The MDR

is predominantly in one section for the smaller rigs and as little as two sections for larger rigs. An important characteristic of the MDR's mast is that no cranes or pull trucks are required to assemble the mast or raise it. The mast connections and raising process may be carried out with the touch of a button. This type of mast typically has ancillary benefits to the operator and contractor. For the operator, it means smaller drilling sites are constructed, and reduced risk of accidents; again converting into well cost savings and preservation of the environment. For the contractor it means a quicker rig up time, less equipment at site to co-ordinate, and again reduced risk of accident, which translates into an improved financial bottom line and retention of quality employees from improved working conditions.

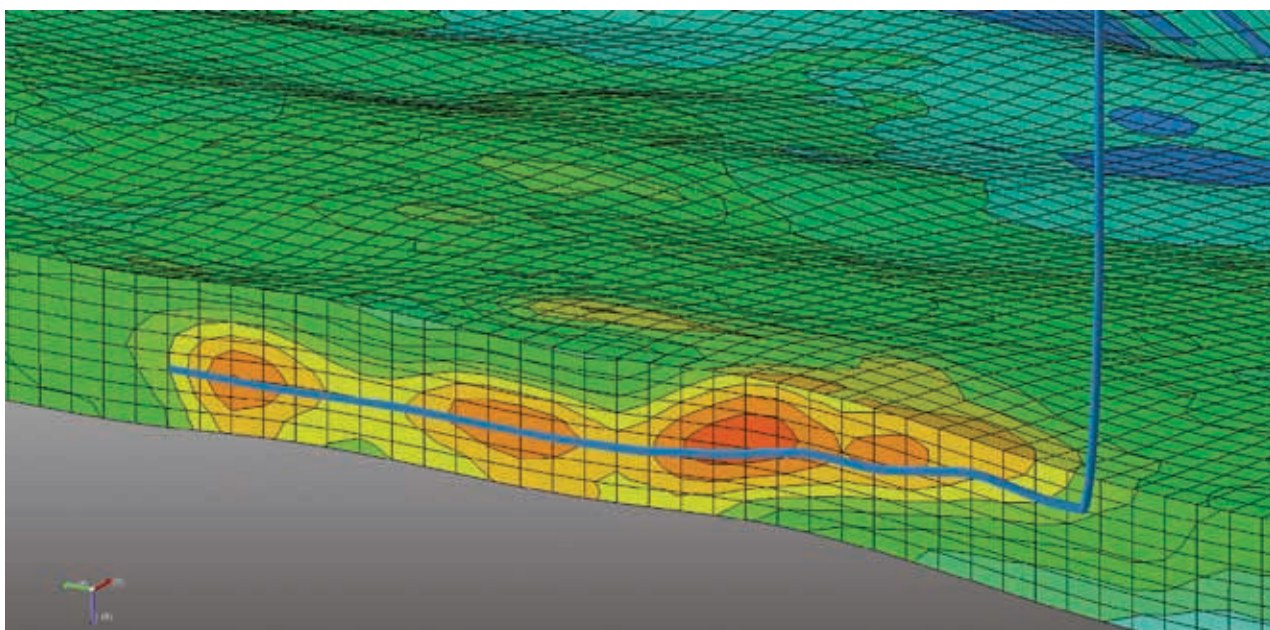
A 353 mT MDR hook load capacity class or less may now be rigged down, moved 16 km down the highway, and rigged up in less than 24 hours. A rig in the 363 mT or larger capacity in same scenario is less than 72 hours. More importantly, the MDR mast itself can be transported down highways with a height restriction of 4.5 m or less. Also these rigs are moved with less truck loads; 226 mT MDRs can be moved in less than 17 loads and a 363 mT or larger rig may be moved in as little as 24 loads.² Finally these designs are between 22 - 30% lighter than their conventional predecessor in the same class, from 10 years ago. The lighter rigs cause less damage to the roads during transport. All these features create cost savings for the operator in moving the equipment, and less wear or damage to the environment.

On a pad well programme, MDRs are fitted with equipment for safe and efficient moving. They 'walk' or 'skid' between wells at a minimum rate of 30 ft/hr (9.1 m/hr). The most advanced MDRs will have 72 points of movement on a 360° access with the least advanced MDRs having 8 points of movement for walking. For the operator, a greater range of movement



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means the ability to re-arrange well site drilling sequences as needed. The contractor achieves better safety and less time between drilling operations, which again contributes to their bottom line.

Enhanced drilling flexibility

Diversifying between different types of well drilling programmes and roles with one rig based on the needs of the operator may mean the end of the traditional rating systems as the industry understands them today. For instance, conventional rigs are often referred to as 1500 HP (1119 kW), or 2000 HP (1491 kW) rigs which ultimately refers to the draw works pulling capacity. It is no longer common for MDRs to use draw works, as they are less efficient, more expensive to maintain and lack the accuracy of new pulling systems. Also, with better drilling techniques and improved materials, what used to weigh 100 t when pulled from the hole and measured 2743 m in length may now measure up to 4876 m in length.

The MDR is usually rated across several measurements. These include (a) hook load rating, (b) mud pump horsepower and pressure, which relates to how much fluid may be pumped in the hole to keep it lubricated, stable and clean, (c) estimated measured depth length that can be drilled within any given size of hole based on typical rock formations. These measurements incrementally save the operator money on logistics, day rate, equipment requirements and total time/cost to complete the drilling programme; as fit-for-purpose equipment can be chosen or in the case of the MDR, programmed for the drilling parameters. MDR drilling results have been recorded where a 226 mT hook load unit, with 3200 HP (2386 kW) mud pumps has drilled to 4876 m measured depth wells.³ That same footage, 30 years ago,⁴ would have required a conventional rig three times the size of the MDR used in the aforementioned example. Better engineering, materials, drilling knowledge and a programmable logic controller (PLC) have improved accuracy; digital interfaces are now providing a level of refinement that traditionally has not been available on conventional drilling rigs.

The digital MDR

The software integration on MDRs has allowed some drilling tasks to reach #8 on Sheridan's 10 degrees: specifically "Executes automatically, and informs the driller only if asked";⁵ pro-actively changing weight, rotational speed and pressure to keep rate of penetration [ROP] optimised⁶ based on real time data being delivered from the drilling sensors. Advanced MDRs also have supervisory control and data acquisition [SCADA] systems. These "automated drilling systems...are expected to allow rigs to consistently attain high productivity levels";⁷ with direct participation in the drilling process by the E&P company during live drilling operations.

Smaller but stronger

In the longer measured depth wells, larger diameter pipe is typically required. With the larger diameter pipe, additional space and power is required to 'rack' the pipe in the mast⁴ and rotate it. This problem was recognised as far back as 1987; for which the MDR provides a solution. Automated pipe handling has replaced racking, and not racking in the mast means storage space (offset) on the rig floor can be reduced. Eliminating the need to carry the additional pipe storage and material weight on the rig floor allows the structure and weight of the MDR to be significantly reduced.^{9,10} With no restriction on floor storage capacity operators now have the option to easily continue drilling till another bottleneck is reached such as hook load or torque capacity of the MDR. With this change, fewer technicians are needed to manage all the equipment and pipe in the same way.

People, still the key to success

MDRs usually require fewer people to maintain, repair and operate the unit. Having said this, as Rassenfoss¹¹ points out, although people are removed from the floor, and MDRs can be operated with less people, it does not mean headcount is reduced. With a high performing modern rig, these traditional technicians are re-tasked with other responsibilities,¹¹ ultimately improving performance.

Finding qualified technicians continues to be a challenge for both operators and contractors and represents one of the drivers behind the deployment of MDRs initially. Workers' hours can range from 8 hour to 12 hour shifts; with a great deal of the time spent in exhaustive, repetitive activities. The rate of turnover for new hires ranges from 26 - 74%¹² during the first 30 days of employment. Further challenges occur when limited applicable job training courses are available, which means that finding experienced personnel to operate an MDR today may be more difficult than five years ago.

This is a concern for the MDR contractor; an equipment package made up of hydraulic, electric and mechanically controlled equipment interfaced via software and PLCs; and has a variety of sensors for drilling and monitoring requires a different type of rig technician to maintain and operate it. University associate degree programmes¹³ exist to provide technicians with the qualified training that contractors desire to repair and maintain the modern rig. Finding or training qualified people is a joint effort by rig manufacturers, contractors and operators alike. The industry recognises the need and is attempting to respond. In the end, people may be the bottleneck that slows down the global fleet adoption of MDRs.

Summary

The MDR in 2014 demonstrates levels of performance, safety and efficiency that significantly outperform classic or conventional rigs. Performance and safety systems such as: (a) automated pipe and casing handling, (b) mobility, (c) flexibility to adapt, (d) digital interfaces, (e) smaller size and (f) employing better qualified technicians characterise the MDR. Operators, contractors who use MDRs and the rig manufacturers themselves are dedicated to improving safety and performance in the drilling industry. ■

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RIG SITE CONSTRUCTION: LAYING THE FOUNDATION

Jeff Juergens, Newpark Mats and Integrated Services, USA, explores recent developments in rig site containment technology that are helping operators make cost and efficiency savings from the ground up.

The tremendous growth of unconventional shale gas development in populated areas like the Marcellus and Utica shale plays, and the increased regulatory scrutiny that accompanies it, are ushering in a new era in rig site containment. Operators are looking for new ways to meet regulatory demands while maintaining their bottom line; at the same time, there is also an increasing emphasis on technologies that enhance worker safety and meet new environmental standards. Ultimately, these trends are driving innovations that will make oil and gas operations more environmentally friendly, safer and more cost-effective.

The consequences of noncompliance

Rigorous new regulations and standards have recently been enacted in order to prevent ground contamination from spills. Potential site contamination from spills of any kind, including liner breaches, can be



Figure 1. Workers prepare a drilling site in the Marcellus using the DURA-BASE system in conjunction with a layer of spill containment liner.



Figure 2. Ground level image of a rig installation on soft soil with DURA-BASE in South Louisiana.

detrimental for drilling rig operations, driving up operator costs from the non-productive time associated with liner repair and potential spill management. Additionally, operators may be subject to stiff fines for spills related to torn liners. As a result, they have begun to search for high-quality products that can provide protection against these risks, minimising environmental impact and operating costs. And it is not just about short-term, project-based solutions; failure to comply with environmental regulations can also have long-term effects on the public perception of a company and must be avoided at all costs.

Innovation

Newpark is always looking for ways to innovate new site containment and ground protection solutions that minimise the environmental impact of oil and gas operations, and foster safer worksites. Some new developments for the DURA-BASE® Advanced-Composite Mat System provide an additional level of security while delivering substantial environmental and worksite safety benefits. This includes an interlocking design that helps eliminate differential movement and shifting, offering better worksite stability and reducing the chance of slips, trips and falls.

With their interlocking feature, the mats also prevent pinching and gapping, thereby delivering a more 'liner friendly' alternative for site containment than other conventional solutions. Of course, a longer-term solution would favour matting systems that can be run without liners, which is a development that is currently being worked on.

DURA-BASE mats have enhanced resilience and longevity, lasting about five times longer than wood mats. They also deliver improved weight distribution and are tested to withstand loads of up to 600 psi. They are manufactured as a single, non-absorbent piece, which means that the mats do not harbour contaminants as they are transported from site-to-site, which is a risk posed by conventional alternatives. Additionally, the mats are more environmentally friendly than other offerings, due to their long-term reusability and the company's proactive approach to developing and utilising a sustainable recycling programme.

Operator challenges

Operators encounter unique challenges on each job when working to prevent spills and liner breach. In an effort to enhance protection, some operators have increased the thickness of their liners. However, liner breaches continue to occur due to the wear and tear caused



by heavy equipment and vehicle traffic, prompting regular repairs and downtime. To remedy this, operators sometimes use wood mats to protect the poly-liners, but this actually compounds the problem, as the wood mats frequently pinch and tear spill containment liners. Unsurprisingly, there is often a great deal of operational time and costs associated with these added measures. Ultimately, liner maintenance, work delays, potential spills and resulting DEP citations can all drive up operating costs.

The cleaning process for matting systems is another additional delay and expense that operators must consider. Wooden mats are difficult, if not impossible, to clean and tend to soak up contaminants, leading to cross-contamination between sites. They also commonly have debris lodged in the wooden matrix of the mat, which poses the risk of debris falling onto roads during transit and jeopardising the safety of motorists. These challenges, when compounded, also add to operating costs.

DURA-BASE mats are much easier and faster to clean, potentially shaving days off cleaning time. The mats also integrate with an automated system called the T-REX™ Mat Cleaning System. By automating the mat-cleaning process, the guesswork is taken out of estimating cleaning costs upfront, while speeding up remobilisation.



Figure 3. Aerial image of a rig installation with DURA-BASE in Poland.

When deployed properly, these mats can reduce site construction costs by minimising or eliminating the need for a sub-base, along with the related trucking, remediation and disposal costs. Overall pad construction costs, from sub-base construction, liner materials, trucking expenses, labour, remediation and waste disposal, are all hidden costs that are often overlooked. Low quality matting systems really drive up these costs for operators. Use of wooden mats also results in additional costs for landfill use or incineration as methods of disposal.

Safe solutions

In addition to providing a continuous work surface, DURA-BASE mats are designed with an anti-skid tread pattern that helps prevent worker injury. The mats also weigh half as much as wooden mat alternatives and allow for twice as many mats to be carried on each truckload. Reducing truck traffic minimises the risk of motor vehicle accidents on or around the well site, which is the leading single cause of death in the industry (source: NIOSH). In addition, the mats are constructed from an advanced-composite material with an anti-static additive that eliminates potentially dangerous static build-up.

Improving efficiencies

Operators gain improved operational efficiencies by drilling and completing from the same pad. In these instances, the interlocking 'liner friendly' design can eliminate the need for a second liner when moving to the completion process. When using separate liners for the drilling and completion, liners can cost up to US\$ 150 000 to US\$ 250 000 per pad. DURA-BASE can help reduce that cost, while virtually eliminating the US\$ 20 000 to US\$ 30 000 average cost of liner maintenance. With single pad site preparation, the pads can also be quickly reconfigured or resized without having to reinstall the matting system, which is important for completions since they typically require a larger pad area.

Case history

Back in 2009 one Houston-based operator started using the DURA-BASE system as an integral component of the company's drilling pad site preparation and site containment measures in the Marcellus Shale.

Since initially trying the system, the operator has continued using it as a best practice for drilling projects throughout the Marcellus and has expanded its use to Colorado, with impressive results including significant time and cost savings.

Exploring abroad

The company spread the use of the system to its drilling operations in Poland in 2011; bringing this best practice to bear was an obvious solution to the challenges of drilling there.

When the operator came to Poland, it discovered that the terrain was more difficult and it needed to deploy a rig matting solution that would protect the spill containment poly-liners and allow for safe and efficient delivery of the wells being drilled. The company wanted to bring DURA-BASE in because of its terrain flexibility and its prior performance on jobs in the USA. The solutions typically used for site preparation in Poland were less than ideal.

Before the company decided to use the system on this project, service crews were planning to use locally sourced concrete plates. Typically used to prepare sites for drilling projects in Poland, these 5 ft x 6 ft, 6 in. thick plates are extremely heavy and unwieldy, making them quite difficult to transport and deploy.

It takes 200 truckloads to build a location with these concrete plates and only 14 truckloads with the lighter-weight mats; this is a significant advantage from a cost and logistics standpoint. Fewer truckloads save valuable time and money.

Despite their comparatively low weight, the rugged interlocking design of the mats also remedied other drawbacks of using concrete plates, such as their tendency to break easily or wear holes in poly-liners used for spill containment. The system protected liners from tearing, thus helping to protect the environment.

There was some initial scepticism and friction on the part of regulators, as is often the case when introducing new technologies. For example, there was some initial resistance based on concerns about sparks and the flammability. But this was resolved when the

local regulatory board was shown how the mats are designed to be fire resistant and how they dissipate static build-up.

Once DURA-BASE was cleared by regulators, it was full steam ahead. The operator's crew got to work prepping the site and installing the mats. Since the system was developed with shifting surfaces in mind, it drastically reduced the stone and associated trucking necessary to support the rig and allowed the drilling team to get to work more quickly.

The concrete plates were difficult to move and would have taken upwards of three weeks to deploy based on all the trucking and added weight. But with the mats, the operator was able to get the rig site prepped in under a week. Newpark made sure that one of its representatives was onsite to oversee the installation, ensuring everything went smoothly and without delay.

Poland – and beyond

As the shale-gas potential in Poland continues to be explored, one thing becomes clear: companies that want to take part in developing challenging shale plays like the Baltic, Podlasie and Lublin basins need an edge that will help them minimise costs and boost efficiency wherever they can. DURA-BASE is a field-proven way to do just that.

With the higher costs of drilling in Poland, solutions like this are a key way of minimising project expenses and enhancing HSE. However, the benefits of this system extend far beyond shale gas exploration in Poland. Whether operators are developing oilsands in Alberta's muskeg, drilling for oil in the Permian basin and Amazon jungle or developing unconventional gas in the Marcellus and Utica, specialised mats can help. ■



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DEFINING THE NEED FOR RCDS

Jason L. Shaffer, Pruitt, USA, explains how rotating control devices can be customised to applications and help improve drilling safety and efficiency.

The primary safety concern on every drilling rig is maintaining a barrier between the open hole and the surface. Traditionally this barrier has been composed of the column of drilling mud circulated throughout the wellbore. This was adequate long ago, before the days of environmental protection and drilling at high pressures miles beneath the earth's surface. However, as drilling technology has flourished, the dangers of drilling at greater depths have evolved as well. Risks range from lost productivity while circulating a kick, to blowouts resulting in loss of lives and the uncontrolled release of thousands of barrels from a well. Today these risks can be mitigated or averted all together. The advent of the rotating head, or rotating control device (RCD), has presented the drilling industry with an additional safety barrier atop the traditional BOP stack.

As the drilling industry focuses more explicitly on safety, the RCD is concurrently growing to become an integral component atop the traditional BOP stack. API 16RCD outlines design and test specifications, defining an RCD as "drill-through equipment designed to allow rotation of the drill string and containment of pressure by the use of seals or packers that seal against the drill string (drill pipe, casing etc.)." Comprised primarily of a wellbore seal attached to a bearing, an RCD diverts annulus returns away from the rig floor, sealing like a rotating annular BOP, but without inhibiting movement or rotation of the drill pipe. An RCD can even be used in collaboration with the conductor pipe for surface drilling.



Figure 1. Polyurethane passive seal element.



Figure 2. Low pressure RCD bearing.



Figure 3. High pressure dual element RCD.



Figure 4. PRCD 3000 high pressure bowl and bearing assembly.



Figure 5. Dual element high pressure RCD bearing.

The advantages of utilising an RCD are numerous. Maintaining a constant seal on the annulus, an RCD does not simply reduce the risk of well control events; it also mitigates hazards when well control events occur by maintaining this constant barrier. Even as tool joints are passed, an RCD prevents uncontrolled fluids and gasses, such as H₂S, from escaping to the rig floor where they can cause explosions, illness, or even death. In addition to safety are the environmental benefits of diverting drilling mud, foam, steam, dust and dangerous gasses to the proper separating and handling equipment. Moreover, there are the improvements to operational efficiency, increasing penetration rates and decreasing non-drilling time with the proper RCD application.

RCD applications

RCDs are utilised in a wide variety of drilling applications, including, but not limited to:

- ▶ Managed pressure drilling.
- ▶ Drilling with lost circulation, PMCD.
- ▶ Underbalanced drilling.
- ▶ Horizontal/directional drilling.
- ▶ HPHT.
- ▶ Geothermal.
- ▶ Reverse circulation.

Sealing the wellbore with an RCD presents the capability to control annular pressure, commonly known as managed pressure drilling (MPD). This is accomplished with the employment of chokes and back pressure pumps, and is commonly used in co-operation with other supplemental equipment for early kick detection. MPD is becoming accepted as the way of the future, dramatically reducing non-productive time, improving rates of penetration, mitigating drilling fluid loss and making the previously un-drillable possible. MPD has presented the ability to drill through zones with poor circulation, and in some cases, total loss of returns with pressurised mud cap drilling (PMCD). In PMCD, a sacrificial fluid is pumped down the drill string while drilling mud enters the annulus through an inlet in the RCD to combine with the cuttings.

In underbalanced drilling (UBD), wellbore pressure is maintained lower than formation pressure. UBD drilling mud may be injected with a variety of fluids to decrease mud density, thus reducing the hydrostatic wellbore pressure; these fluids include: air, mist, nitrogen, natural gas, etc. The underbalanced state of the well results in an influx of formation fluids, and as the well flows, the returns are diverted by an RCD to the proper separating and handling equipment.

As the capability to control annular pressures from the surface has been developed, directional drilling has become more prevalent over recent decades. When equipped with MPD equipment in addition to an RCD, operators have the capability to drill several wells from a single pad or offshore platform. Particularly attractive to investors, directional drilling can be extremely cost and time efficient when compared to relocating a rig for each well. The safety benefits of drilling with an RCD make it an intelligent option for geothermal and other high-pressure high temperature (HPHT) wells. Simply ensure the proper RCD element material is selected and is compatible with mud composition and return temperature.

Types of RCDs

Depending on how the wellbore seal is maintained, API 16RCD classifies RCDs in three categories: active, passive and hybrid (a combination of active and passive). Active RCDs rely on an external hydraulic force to create the seal around the drill string,

and this closing unit has a significant footprint. An additional drawback to active heads is the active design allowing a small volume of wellbore fluid to bypass with each tool joint stripped up, making passive heads the better choice in situations with dangerous gasses. The weak point of an active RCD is the elastomeric bladder (also called the seal element), whose failure commonly leads to contamination of the hydraulic system and time-consuming repairs. Because of this, active and hybrid RCD systems require operators onsite and are typically more expensive to operate and maintain.

This has led the industry to lean significantly in the direction of simpler passive RCDs, which seal around the drilling string with an elastomeric seal element mounted to an RCD bearing. Most passive RCD systems are maintained by rig crew with minimal intervention. Depending on application, passive RCDs may or may not require an external power unit for lubrication and cooling. In February, Pruitt successfully completed field-testing of a self-lubricated 9 in. RCD bearing, sustaining 180 rpm and passing 1600 tool joints over 10 days, all with only one seal element.

Another favourable feature of the passive RCD is the seal elements' shape; their conical design increases sealing capability as wellbore pressure increases. Even as tool joints are passed, passive RCD seal elements form a constant physical barrier between drilling fluids and the atmosphere. They are sized according to drill pipe dimensions and come in a variety of materials, depending on temperature and drilling mud composition. Pressure ratings vary with size and material, and are determined in accordance with API 16RCD test specifications.

Seal element life can be affected by numerous factors, including drill string alignment, drill pipe/tool joint condition, hardbanding and rig operations. A seal element can be consumed within a day when used for fast tripping, compared to an element lasting over a week for drilling. Therefore, the only acceptable measurement of seal element life is tool joint count, which is how they are evaluated in API certification tests. When working with a well-designed RCD bearing, passive seal elements can be replaced within a matter of minutes. This is a tremendous benefit during well control events. The ability to install and remove elements quickly also aids the transition between conventional and MPD drilling. Seal life is heavily reliant on bearing rotation, which indicates the need for a bearing that requires minimal torque to rotate.

A common attribute among all RCD systems is that seal elements are always the weak point. Seal elements require routine replacement just like tires on a car, yet all RCDs cannot produce the same seal element life. The critical factor in extending the life of seal elements is the torque required to induce rotation in the RCD bearing. This breakout torque must be overcome each time the rig stops rotation, whether it be for a connection, flow check, circulation, etc. Additionally, this breakout torque must be repeatable even when rotation is stopped for an extended period, as it is common for a rig to stop rotation for 24+ hours. In summary, an RCD bearing requiring a minimal breakout torque will extend seal element life, thus reducing the number of interruptions to replace elements. All RCD bearings should be torque tested (in accordance with API 16RCD), and a reputable manufacturer will provide this information. RCDs come in countless sizes and pressure ratings, but a breakout torque in excess of a few hundred foot-pounds is absolutely unacceptable.

As the industry leans in favour of passive RCDs, competition flourishes with companies marketing them. RCDs are not simply dumb iron; they are modern machines developed through countless hours of engineering, research and development. Each year the competitive landscape transforms, as names change while large oilfield service corporations acquire smaller companies, so that they may sell their products without bearing the cost of development. As with any oilfield rental equipment, service is crucial, and the best service is provided by companies who have put forth the effort developing their own product. All RCDs are not created equal, and a few key attributes set them apart. The most efficient RCDs are the ones that result in the fewest interruptions to normal drilling operations.

RCD features

A foolproof mechanism for securing the bearing atop the annular BOP is critical, as valuable rig time can be wasted repeatedly attempting to secure a poorly designed RCD bearing; furthermore, an unseated bearing could result in loss of well control. Some designs utilise internal hydraulic latches to engage multiple locking dogs with the bearing's OD inside the wellbore. These internal latches are sensitive to drill string misalignment, which can complicate the bearing install process. Another drawback to the internal latch design is



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Figure 6. Dual element RCD bearing installing on a tool joint.



Figure 7. Dual element RCD installed atop a BOP stack.



Figure 8. Drilling mud circulation path.

contamination with drilling mud, leading to pack off behind the locking dogs. In this case, the bearing becomes stuck, and the latch must be nipped down from the BOP stack, resulting in an NPT nightmare, especially if paired with a well control event! This risk can be partially mitigated by installing a protective sleeve (while the RCD bearing is not installed), but this represents another cumbersome and time-consuming installation, which will also prohibit quickly switching between MPD and conventional drilling. These internal latches rely on a variety of mechanisms to indicate whether a bearing is securely latched because the engagement is not visible inside the wellbore.

External clamshell-type clamps are simpler with fewer moving parts and cannot be contaminated by drilling mud. Available in both manual and hydraulic operation, the design consists of two half-shell 'C's, each engaging one side of the bearing. A tremendous safety benefit in this design lies in the fact that the clamp engagement is highly visible, assuring no potential for bearing ejection and loss of well containment. These clamps can be easily operated by rig crews and are assured to work without requiring repeated attempts.

To ensure effortless operation for rig crews, well designed RCD systems remain simple. Look for continual lubrication in high pressure RCD systems, not reliant on additional compensator pumps to activate with variations in wellbore pressure. The ability to carry out a quick system check from the rig floor with a glance at clamp station gauges is advantageous. Another valuable feature is the capability for the service company to remotely check on the system via phone or internet, never disrupting the rig's operations. This provides the capability for the service company to observe and prevent problems before they arise. The use of systems that require full-time operators and supplemental accessories, such as running tools, flushing systems, or protective sleeves, should be questioned, as they consume valuable rig time while adding no value.

In addition to providing a redundant seal, bearings equipped with dual seal elements can accommodate greater misalignment of the drill string and substantially extend seal element life. Once committed to employing an RCD, use of dual seal elements should be given serious consideration, especially in circumstances involving dangerous gasses. An efficient RCD system will not only minimise the number of seal element changes, but also the time required for replacement. Replacing a bearing with dual seal elements follows the same procedure, and requires no more time than replacing a single element. It is good practice to always have a spare bearing on standby with new seal elements ready for a quick change. Remote operation of the clamping mechanism presents a great safety advantage, not requiring personnel beneath the rig floor, and these systems are prevalent. Yet some customers prefer the simplicity of a manual clamp, and those are easily sourced as well. A good service oriented company does not hesitate to customise orders for their clients.

Summary

It is important to note that an RCD is always used in addition to, not in place of, traditional blow out preventers. The RCD is a drilling tool, providing a drastic improvement to drilling operations, not well control equipment. The RCD has made drilling safer for decades, diverting drilling fluids and dangerous gasses away from personnel. However the evolution of the modern RCD has surpassed that initial benefit by leaps and bounds. Modern models can be found with pressure ratings in the thousands and have led to the development of more efficient drilling methods, literally making the un-drillable drillable. For practically any operation, safety and drilling efficiency can be improved with a RCD. Regardless of how a rig is equipped, an RCD can be customised to meet its needs. ■

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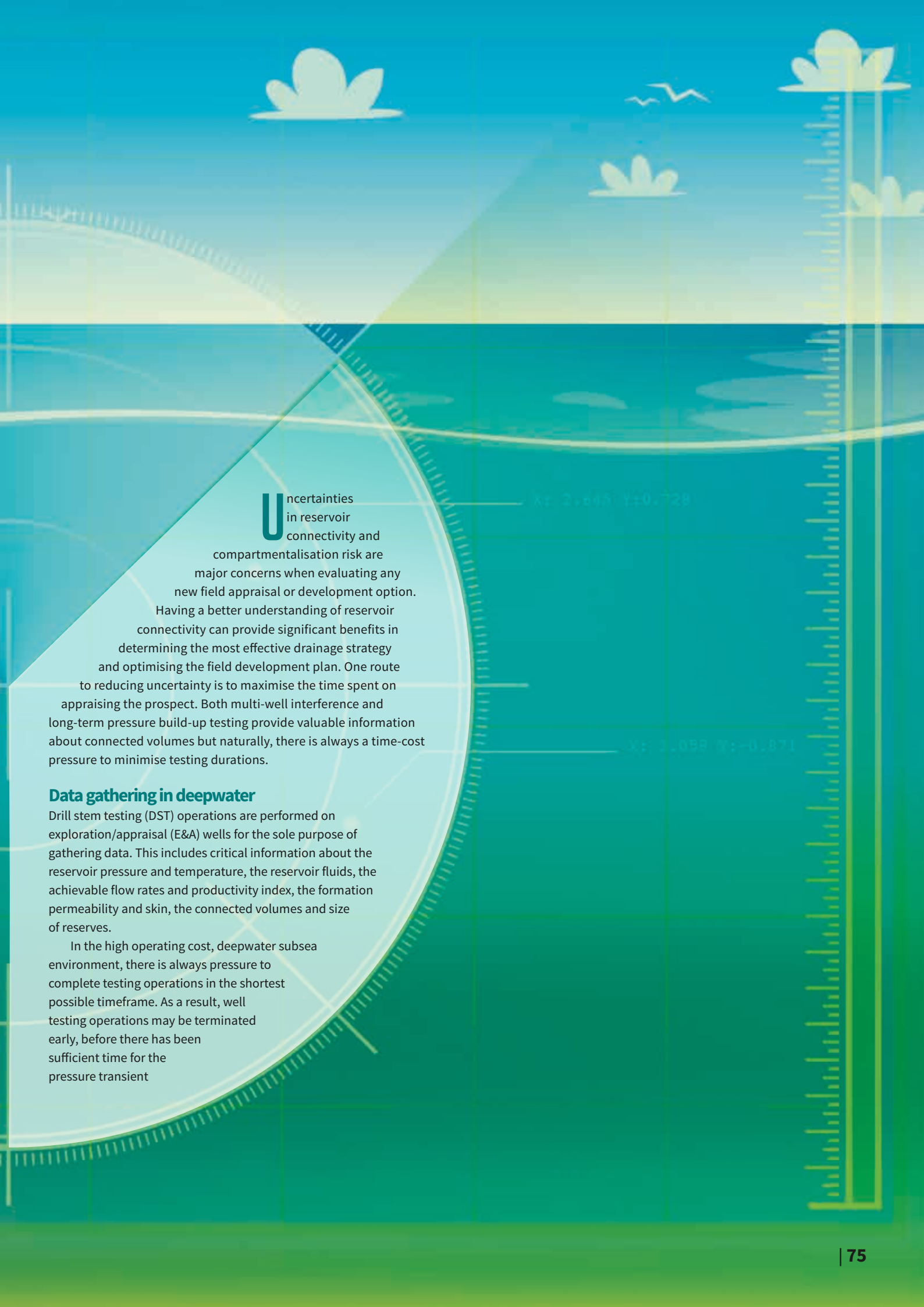


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REDUCING RESERVOIR UNCERTAINTY

Gaining acceptance of any new technology - in what has traditionally been a risk-averse industry - has never been easy. Brian Champion, Expro, UK, explains how the industry is embracing an emergent wireless monitoring technology to reduce reservoir development risk and enhance well safety.



Uncertainties in reservoir connectivity and compartmentalisation risk are major concerns when evaluating any new field appraisal or development option.

Having a better understanding of reservoir connectivity can provide significant benefits in determining the most effective drainage strategy and optimising the field development plan. One route to reducing uncertainty is to maximise the time spent on appraising the prospect. Both multi-well interference and long-term pressure build-up testing provide valuable information about connected volumes but naturally, there is always a time-cost pressure to minimise testing durations.

Data gathering in deepwater

Drill stem testing (DST) operations are performed on exploration/appraisal (E&A) wells for the sole purpose of gathering data. This includes critical information about the reservoir pressure and temperature, the reservoir fluids, the achievable flow rates and productivity index, the formation permeability and skin, the connected volumes and size of reserves.

In the high operating cost, deepwater subsea environment, there is always pressure to complete testing operations in the shortest possible timeframe. As a result, well testing operations may be terminated early, before there has been sufficient time for the pressure transient

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response, being monitored during a pressure build-up period, to adequately investigate any far boundaries. This can mean that critical decisions regarding future field development plans are taken based on limited and insufficient data sets.

A wireless approach to reservoir monitoring and control

By the application of a novel cableless telemetry system (CaTS™), well testing no longer has to end at well abandonment. Expro's Advanced Reservoir Testing™ service enables abandoned wells, zones or pilot holes to be monitored for extended periods beyond final well abandonment.

Based on electromagnetic (EM) data communications technology, the system wirelessly transmits high quality pressure and temperature information from the reservoir to seabed using the well's

tubing, casing or liner as the transmission medium. Signals can also be transmitted from seabed to reservoir, to command and control downhole hardware such as flow control devices.

Under favourable well conditions, the wireless technology has achieved very long point-to-point transmission ranges in excess of 12 500 ft, meaning the quantity of in-well equipment is minimised, resulting in reduced deployment time and savings on well monitoring costs.

Of critical significance, the EM technology does not require a tubing string in the well to communicate along, and the signal is not attenuated by cement plugs, bridge plugs or cemented casing or liner. This makes the system well suited to operating in the permanently abandoned well environment, where typically only cemented casing or liner strings remain in the well.

Whilst non-ideal, where the metallic structure of the well may be non-continuous between the point of data transmission and data collection, for instance between a sidetrack and a mother bore, there are options to 'short-hop' the data over the gap.

The system uses standard completion components so there is no requirement for special plugs or packers, thus minimising deployment costs. It can be retrofitted into existing wells using either wireline or coil tubing, externally or internally mounted on a tailpipe below a permanent packer during DST, or alternatively, deployed as part of a lower completion assembly for sandface monitoring.

Post-abandonment reservoir monitoring

Using the CaTS wireless gauge technology, it is possible to instrument a subsea E&A well at the time of final abandonment so that it can be used as a high value, long-term, monitoring asset for years beyond abandonment.

Exploration and appraisal wells are typically permanently abandoned after logging or after short periods of production testing and without obtaining any long-term pressure data, thus losing a valuable opportunity to prove the reservoir model. By installing a wireless transmitting pressure/temperature gauge into the well at the time of well abandonment, it is now possible to acquire high quality reservoir pressure data for periods of several years beyond abandonment.

Post-abandonment reservoir pressure data is being used by operators to monitor for connectivity with adjacent assets that are either being produced, or injected into, and also to collect long-term pressure build-up data to investigate far reservoir boundaries and establish connected volumes. This is proving to be highly valuable information that would not be detected during the course of a typical 48 or 72 hour pressure build-up performed during a DST. In either case, high value reservoir information is being collected over long monitoring periods and at low incremental cost.

By using the well's steel liner or casing as a signal conduit, the data is transmitted from the reservoir to the seabed wirelessly. The CaTS gauge uses a high specification quartz crystal pressure sensor featuring high accuracy, high resolution and excellent long-term stability performance, which is critical when very small pressure changes need to be detected accurately and consistently over long monitoring periods.

The pressure data is transmitted using a digital signal, providing reassurance that there will be no loss of fidelity in the data quality resulting from the wireless transmission process.

Being addressable, multiple discrete zones can be monitored in a well, with up to 20 zones having been instrumented successfully in a single well (SPE paper 102745).

The pressure/temperature data being transmitted from downhole is stored at the seabed in a battery powered, remote

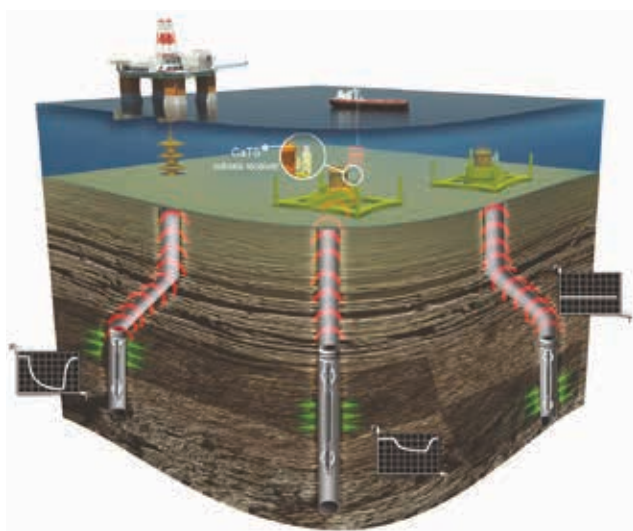


Figure 1. Advanced reservoir testing allows well testing to continue beyond final abandonment.

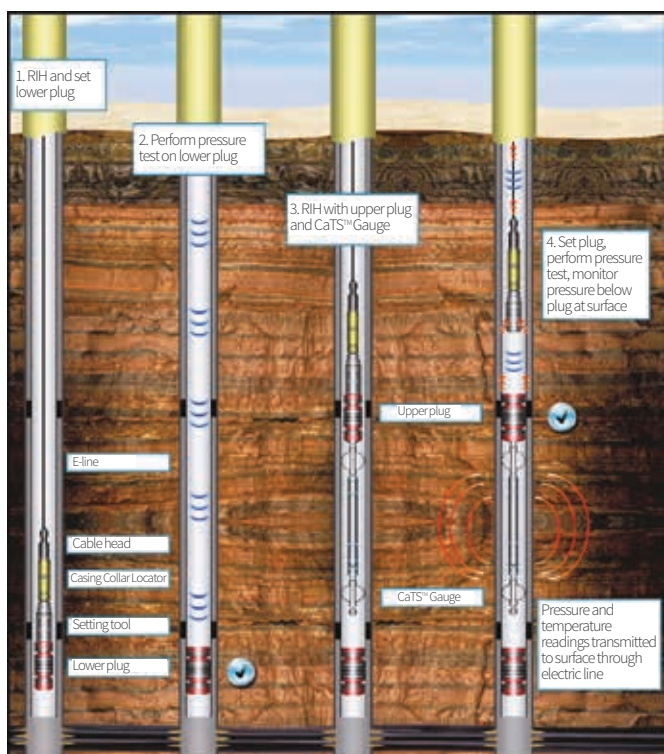


Figure 2. Barrier verification during well suspension or P&A.

subsea receiver, which is rated for operation at water depths of up to 10 000 ft. The mounting arrangement for the receiver is flexible and may be deployed on the well debris cap or where required, it may be integrated into an anti-trawl frame seabed protection structure. The data is subsequently collected from the subsea receiver by periodically sailing a supply boat overhead the abandoned well location and uploading the data from the receiver's memory using wireless through-seawater communications.

Once installed in an abandoned subsea well there is no requirement to re-enter the well using a semi-sub rig; the only remaining abandonment liability is to sever and recover the wellhead at a convenient time in the future, which can typically be performed using a work vessel.

Clair Field case study

The first successful application of this wireless technology system in a permanently abandoned subsea well took place in an appraisal well on the BP operated Clair Field, located West of Shetland in the UK North Sea (SPE paper 108435).

Being a naturally fractured reservoir, connectivity and compartmentalisation were considered to be key uncertainties in the development planning process for Clair. Since the Clair Phase 1 platform had come on-stream 10 months prior to spudding the appraisal well, there was judged to be an opportunity to monitor the dynamic reservoir response in the abandoned well. The monitoring objective was to identify any depletion due to ongoing production, and to monitor for the impact of pressure support resulting from water injection.

A total of 18 months of high quality wireless gauge data was recovered from the permanently abandoned well, which reduced uncertainties about the Clair reservoir and large-scale connectivity across the field. The CaTS gauge provided a unique insight into the pressure profile across the field, helping to give BP and its partners, a better understanding of the field's complex reservoir formations and structure.

Advanced reservoir testing, using in-well wireless telemetry technology, allows the reservoir engineer to cost-effectively gather critical reservoir connectivity data from an abandoned well or zone for input to the future field development planning process.

Multiple abandoned appraisal wells have now been instrumented with CaTS and data has been successfully recovered wirelessly from wells having reservoirs located more than 10 000 ft below the seabed and in water depths in excess of 7000 ft. These long transmission ranges have been achieved point-to-point without the need for any intermediate relay stations or boosters being installed in the well.

The system has also been installed in exploration wells that are abandoned immediately after open hole logging has been completed and without a DST having been performed. Despite never having been flow tested or cleaned up, high quality data has been collected that clearly demonstrates the reservoir response due to interference effects resulting from production or injection events in the adjacent field area.

Enhancing well safety

There is increasing industry focus on the development and application of new technologies for well integrity monitoring. Examples include the long-term monitoring of the pressure in multiple annuli in subsea production wells, and the verification of pressure barriers during well suspension or plug and abandonment (P&A).

CaTS technology can be flexibly located in the A, B, C, or in fact, any annulus, and the pressure and temperature data can be wirelessly transmitted to a seabed receiver without requiring any annular penetration. Constraints on system longevity, resulting primarily from battery pack performance and the inherent self-discharge effects, currently limit the operation of the annular monitoring system to a few years. However, options are being considered for delivering life of well wireless annulus monitoring to address this limitation.

In terms of barrier verification, the NORSOK Standard D-010 covering well integrity in drilling and well operations requires that a plug shall be verified to the maximum differential pressure at the time of barrier placement. The communications technology is unaffected by bridge plugs or cement plugs, making it well suited to both short- and long-term well integrity monitoring applications.

Barrier verification during well suspension or P&A

During workover or P&A operations, it is common to install both deep and shallow set bridge plugs as temporary barriers at an early stage. In some wells it can be necessary to establish these two barriers deep in the well and relatively close together. The sealing integrity of the lower plug can generally be validated by pressuring up from surface and monitoring for any

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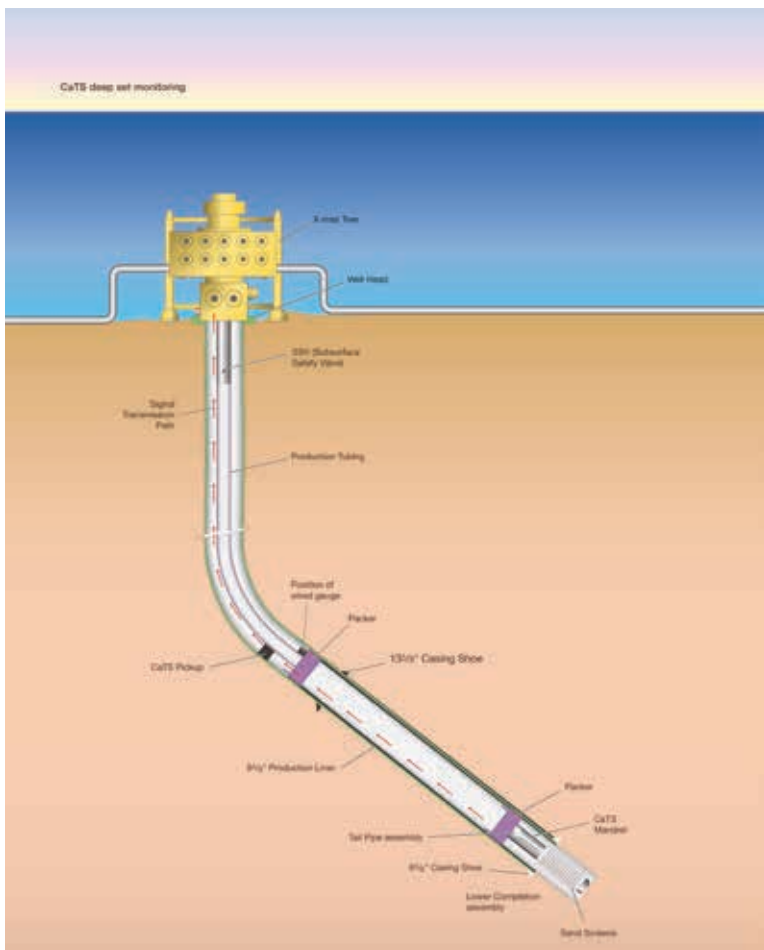


Figure 3. Production optimisation in high rate big bore gas wells.

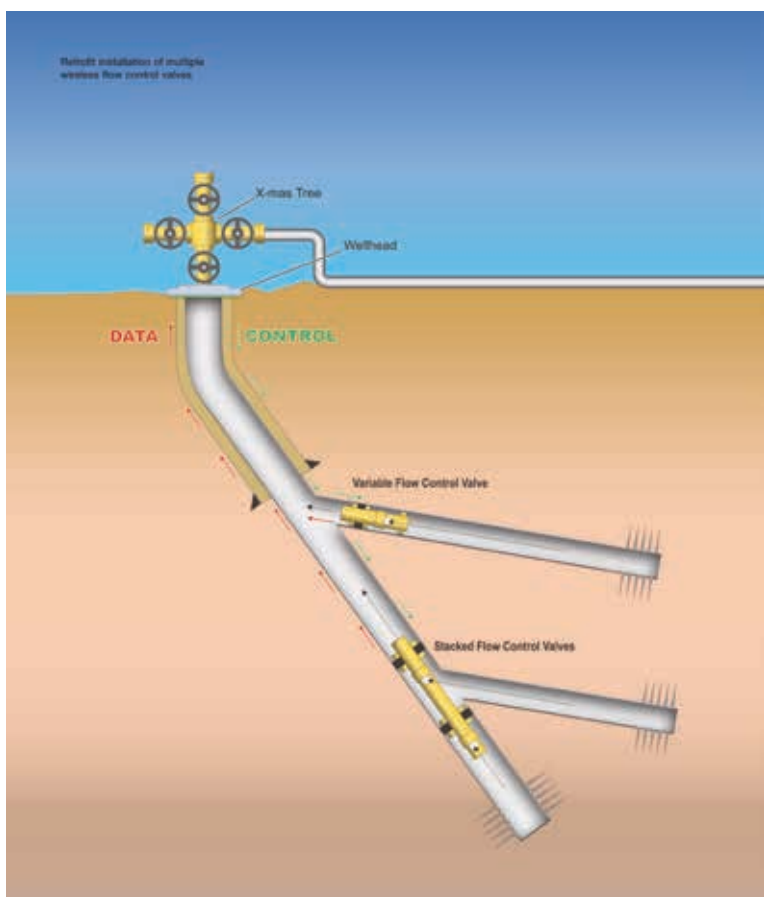


Figure 4. Retrofit flow control for advanced completions.

leakage using the surface pressure gauge. However, when installing the upper plug, and due to the relatively small volume of fluid between the two plugs, it is unlikely that a pressure test applied from surface will detect any leakage past the upper plug.

Thus, when using surface measurements, the sealing integrity of the plug cannot be properly verified at the time of installation by differential pressure testing.

By installing a wireless transmitting pressure gauge below the upper plug, the pressure below the plug can be monitored in real time at surface whilst the pressure testing operation is being performed. This operation requires no additional equipment to be incorporated into the logging string used to deploy the plug, thus there is no compromise to system reliability. It is also compatible with any third party supplied e-line or plug setting equipment and has been successfully applied where the plug is deployed using a well tractor. Most importantly, the plug deployment and monitoring exercise can be completed during a single run in hole operation, minimising costs.

A well abandonment barrier verification campaign has successfully been completed from light well intervention vessels on 10 subsea wells in Norway, with the first application of the technology for barrier verification during P&A in the UK North Sea planned for summer 2014.

Production optimisation in high rate, big bore gas wells

The system is also being applied in the large bore completion environment to deliver a sandface monitoring capability that has enabled production rates to be optimised in high rate gas wells (SPE paper 145581). Six CaTS large bore mandrel systems have been installed in the Shell-operated Ormen Lange Field in Norway. These systems feature full two-way communications between the mandrel located at the sandface and the onshore control room at Nyhamna, enabling gauge settings to be varied and pressure build-up data to be collected. Data from the CaTS systems has been used to optimise production across the entire field.

Retrofit flow control

Where a tubing retrievable safety valve has failed due to plugging or a leak in the hydraulic control line, the valve is rendered inoperable. The absence of a functioning control line means that the deployment of an insert valve is also not possible. Where legislation allows, well production may be re-established by the deployment of a storm choke or ambient valve.

These are generally considered to be temporary flow control solutions used whilst a well workover is being scheduled or alternative remedial activities are planned. Recognising the limitations of these existing remedial solutions, which are not fail-safe or surface controllable, Expro developed the FlowCAT™ retrofit valve. This valve was trialed in an onshore gas well for six months with zero leakage and no false closures observed (SPE paper 130427), however it is yet to be deployed in the offshore platform environment.

Conclusions

This emergent wireless communications technology is seeing accelerated industry adoption for applications throughout



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the well lifecycle. By adopting the advanced reservoir testing approach during the E&A through development phases, CaTS is being used to reduce reservoir uncertainties at low incremental cost.

During the production phase, there are both completion conveyed and retrofit through-tubing products available that are being used to optimise production and to gain an improved reservoir understanding. There are also annular monitoring solutions available that deliver well integrity assurance without requiring any penetration of the annulus.

During well suspension and P&A, this technology is being applied to ensure compliance with monitoring requirements stipulated in well integrity standards related to barrier verification. ■

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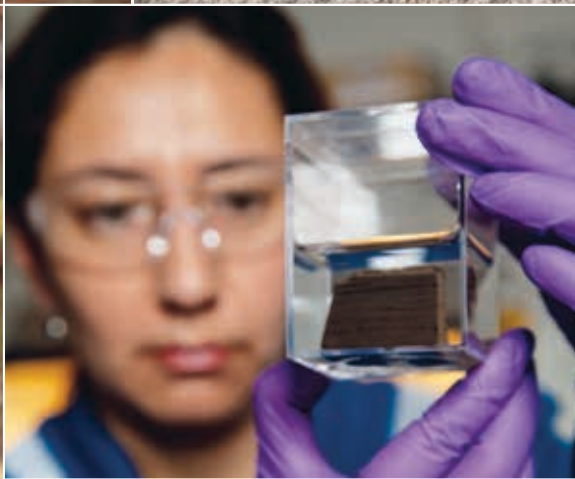
CAUTION:

Loading shaped charges in gun hardware that has not been fully qualified by the shaped charge manufacturer enhances the chance of gun failures, misfires and poor perforator performance. This can also impact production, stimulation and in some cases cause irreparable damage to your customer's well.

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On a recent ultra-high temperature well (432°F) in the Gulf of Thailand, the RHADIANT[†] drilling fluid system proved thermally stable throughout the drilling process and enabled the operator reach production faster with no NPT.

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*Mark of M-I L.L.C. *Welling Report 2014. 59% of operators stated M-I SWACO as the drilling fluids market leader for HPHT applications.