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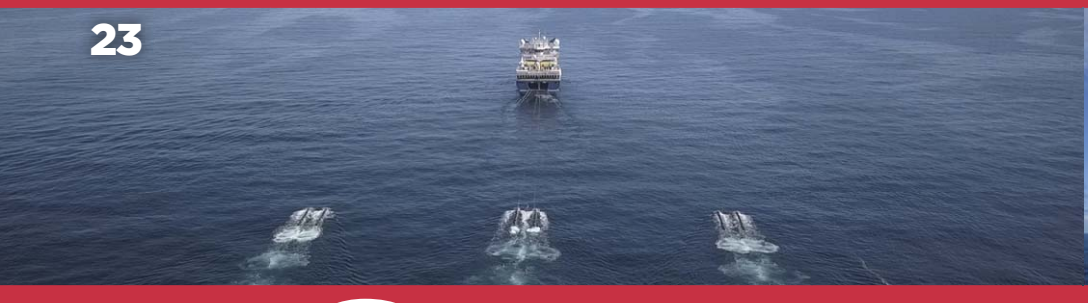

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Spotlight on new TECHNOLOGY

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Comment

September 2018

David Bizley, Editor
david.bizley@oilfieldtechnology.com

The shale boom continues unabated. Despite demand-side issues making the headlines recently, the continued growth of the US shale sector is just as significant.

As prices remain relatively stable in the US$70s, and the sector overall is on track to make a profit, investors are pouring money into shale. Indeed, as Stephen Brennock, oil analyst at PVM Oil Associates, said: "US shale doom-mongers should not get ahead of themselves. They ought to remember that the US shale patch is in better financial shape than ever [...] When it comes to US shale, it is still very much a case of the only way is up."[1]

A recent report by Rystad Energy shows that US shale producers are continuing to spend more money in order to boost their production.[2] Occidental Petroleum has increased its capital guidance in the Permian by US$900 million, Pioneer has increased by US$400 million and Apache and WPX have increased spending by US$400 million and US$250 million respectively. The report does point out that part of the increase is due to service cost inflation, but notes that "a significant part of the incremental budget is also planned to be used for additional drilling throughout 2H 2018 to support more intensive completion activity and production growth in 2019."[3]

In late July, BP agreed to buy BHP's US shale assets for US$10.5 billion as part of the supermajor's first major expansion into the US upstream sector since the Deepwater Horizon spill back in 2010. The assets acquired by the company produce roughly 190 000 boe/d. BP's Upstream Chief Executive Bernard Looney said: "We've just got access to some of the best acreage in some of the best basins in the onshore US, and I think we have one of the best teams in the industry to work it."[4]

The Chinese government is also getting in on the act. Despite escalating tensions over trade tariffs on US and Chinese goods, a US$83.7 billion shale gas deal between China Energy Investment and the state of West Virginia is reportedly going ahead.[5] The deal, signed by President Trump on his visit to China in November of last year, is part of US$250 billion worth of deals agreed between the two countries. Ling Wen, president of China Energy Investment, admitted that the trade conflict between the two countries would likely have an impact on the economics of the deal, but confirmed that it would "be aggressively and soundly pursued under the principle of profit maximisation."[6]

Even local councils in the UK are (admittedly indirectly) now part of the shale boom; through their pension funds, they have invested approximately £9 billion into the industry.[7]

The *Oilfield Technology* team will be at this year's SPE ATCE, held on 24 – 26 September in Dallas, Texas. We'd love to hear from you, so feel free to drop by our stand (#1816) and let us know how your company is pushing the industry forward.

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1. 'US shale growth will offset global production problems over the coming months, analysts say' – https://www.cnbc.com/2018/08/15/us-shale-growth-will-offset-global-production-problems-over-the-coming.html
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Website: www.oilfieldtechnology.com

Subscription

Oilfield Technology subscription rates: Annual subscription £80 UK including postage/£95 overseas (postage airmail). Two year discounted rate £128 UK including postage/£152 overseas (postage airmail).
Subscription claims: Claims for non receipt of issues must be made within three months of publication of the issue or they will not be honoured without charge.
Applicable only to USA & Canada: OILFIELD TECHNOLOGY (ISSN No: 1757-2134, USPS No: 025-171) is published monthly by Palladian Publications, GBR and is distributed in the USA by Asendia USA, 17B S Middlesex Ave, Monroe NJ 08831. Periodicals postage paid New Brunswick, NJ and additional mailing offices.
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World news

September 2018

GlobalData: Refracturing techniques need to evolve to increase success cases for operators in Haynesville

The unconventional horizontal wells that were refractured in Haynesville of Louisiana state in the US during 2017 - 2018 showed a wide variance in economic performance among operators. This highlights the need for refracturing techniques to evolve to increase success cases for operators, according to data and analytics company GlobalData.

A total of 56 wells, which were initially completed between 2008 and 2013, were refractured in Haynesville over the last two years. They had an initial production rate (IP rate) ranging from 320 - 3500 boe/d. The best outcomes are for wells for which their production rate after refracturing is higher than the initial rate.

Out of the total, the 40 wells refractured by QEP Energy showed a good performance, however in many cases productivities were improved with respect to original rates. Indeed, a total of 22 wells recompleted by QEP Energy reached production rates of at least 1700 boe/d, compared to their first IP rate of no more than 1690 boe/d. By contrast, Chesapeake recompleted three wells in 2017 with a poor performance since production rates barely reached 1000 boe/d, nonetheless new wells that were recently turned in line by the operator show production rates of approximately 1740 boe/d.

Adrian Lara, Senior Oil & Gas Analyst at GlobalData, said: "Repeated refracturing of horizontal wells has been much less implemented than vertical refracturing. As a result, there is still a large variance in the results different operators obtain from horizontal well refracturing recompletions."

The recompleted wells in Haynesville that achieved an improved recompletion rate have a break-even gas price of US$2.54/thousand ft^3 and a net present value (NPV) of US$7.38 million. However, for some operators their new wells drilled have better economics than recompleted wells. For instance, Covey Park wells have in average a break-even gas price of US$2.71/thousand ft^3 versus US$3.12/thousand ft^3 for its refractured wells, and an NPV of more than US$3.5 million, higher than the one for recompleted wells.

No operator has consistently achieved US$2 million refracturing cost and therefore reaching high production rates remains determinant in having favourable economic performance.

Lara concluded: "Refracturing techniques will need to continue to evolve in Haynesville to increase the success cases and support a shift where refracturing producing wells is as important in the operator's strategy as is drilling new ones."

Petrofac awarded US$600 million project in Algeria

Petrofac has received a provisional letter of award for an engineering, procurement and construction (EPC) contract worth US$600 million with Sonatrach for EPC1 of the Tinhert Field Development Project in Algeria. Formal contract signing is expected to take place in September 2018.

Located in Ohanet, around 1500 km southeast of Algiers, EPC1 will provide a new inlet separation and compression centre. Under the terms of the 36-month contract, the scope of work includes a pipeline network of approximately 400 km to connect 36 wells, along with commissioning, start-up and performance testing of facilities.

E S Sathyanarayanan, Group Managing Director, Engineering & Construction, commented: "This award builds on Petrofac's significant track record in Algeria where we have been working in support of the country's oil and gas production for more than two decades.

"We have continued to grow our presence in-country through a number of major EPC and engineering services contracts with Sonatrach, including the Alrar and Reggane projects that commenced production this year, and look forward to deploying our expertise to deliver this project with operational excellence and safe project execution at the core of our approach."

In brief

Brazil

Norwegian state player Equinor has announced that with daily oil production of over 90 000 bpd from current fields and with expected investments of more than US$15 billion until 2030, Brazil has become a core area for the company.

"We have been building a presence in Brazil since 2001, and we have been able to establish a broad energy portfolio in the country. With around US$10 billion already invested, and more than US$15 billion expected to be invested until 2030, we show how we are working to create value for both Brazil and Equinor," says Anders Opedal, executive vice president for Development and Production Brazil in Equinor.

Egypt

Eni has made a gas discovery in the Egyptian Western Desert. The discovery well has been drilled on the Faramid South exploration prospect located in East Obayed concession, 30 km North-West of the Melehia Concession. The well reached the target depth of 17 000 ft and encountered several gas bearing layers in the Kathabta sandstones of Jurassic age.

The well has been opened to production delivering 25 million sft^3, confirming the potential of the East Obayed Concession. Eni has started the studies to develop these relevant gas reserves that, together with the gas potential of the Melehia Concession, can contribute to increase the country's gas production from the Western Desert Basin.

Eni, through its Operating Company AGIBA, which is equally held by Eni subsidiary IEOC and the Egyptian General Petroleum Corporation (EGPC), currently produces 55 000 boe/d from the Egyptian Western Desert. AGIBA owns 100% of the East Obayed Concession.

World news

September 2018

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17 - 20 September, 2018

Gastech
Barcelona, Spain
E: info@gastechevent.com
www.gastechevent.com

24 - 26 September, 2018

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Dallas, USA
E: sales@spe.org
www.atce.org

27 - 28 September, 2018

Artificial Lift 2018
Dallas, USA
E: delegates@iQ-Hub.com
www.artificial-lift-conference.com

12 - 15 November, 2018

ADIPEC
Abu Dhabi, UAE
E: adipec.enquiry@dmgevents.com
www.adipec.com

27 - 29 November, 2018

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Marina Bay Sands, Singapore
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- EM&I complete successful ExPert™ Trial
- J2 Subsea 4 Port Tool Changers to be used for first time on Brazilian MOBO campaign
- Empyrean Energy PLC: Alvares 1 testing and operations update, Sacramento Basin, California
- Mitigating corrosion in ageing gas fields

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Yokogawa wins orders for oilfields offshore Norway

Yokogawa Electric Corporation has announced that its Norwegian subsidiary, Yokogawa TechInvent AS, has received orders to provide 59 high-performance FluidCom chemical injection metering valves for two offshore oilfields that are being developed by Equinor ASA. One destination is the Johan Sverdrup field in the North Sea, 160 km west of Stavanger, and the other is the Johan Castberg field in the Barents Sea, 240 km northwest of Hammerfest. The orders for the FluidCom valves were placed through the suppliers of the chemical injection packages for these projects.

The Johan Sverdrup field is estimated to have reserves of between 2.1 and 3.1 billion bbls, making it one of the five largest oilfields on the Norwegian continental shelf. Oil and gas from this field will be piped to separate onshore facilities. For the Johan Castberg field, which is estimated to have reserves of 450 to 650 million bbls, the plan is to use a floating production, storage and offloading (FPSO) vessel. The orders are for phase 2 of the Johan Sverdrup project and for the Johan Castberg project. Both projects are scheduled to start operation in 2022.

Shigeyoshi Uehara, head of the IA Products & Service Business Headquarters, comments as follows about these two orders: "We believe that the selection of the FluidCom valve by Equinor, a company that is renowned for its advanced technology and leading role in efforts to achieve the Sustainable Development Goals (SDGs), was based on a very positive evaluation of its features. By enabling the remote control of chemical injection, FluidCom valves reduce the amount of work that must be performed under very demanding conditions on offshore platforms. Optimisation of the chemical injection amount also protects the environment. FluidCom valves thus help our customers achieve significant reductions in Opex and contribute to the achievement of the SDGs. By expanding its lineup of upstream solutions with products such as the FluidCom valve, Yokogawa is providing new value to its customers."

FuchsRohr AluDrill enhances operational efficiency in extended reach drilling

With its FuchsRohr AluDrill pipe OTTO FUCHS Drilling Solutions has produced a reliable and cost-efficient solution for today's modern drilling market that increasingly relies on multilateral and extended reach applications. The latest record depth of almost 15 km on Sakhalin island and current efforts in Brazil to drill even deeper show that there is a clear trend toward maximising recovery at existing reservoirs. The question is often the price tag.

Reduced costs and improved drilling efficiency play an important role in extensive efforts to make full use of remote sources. Through in-depth, full-scale testing, the AluDrill aluminium alloy pipe has proven that its material properties are best suited for these kinds of extreme applications. Measurements show a significant reduction in torque and drag forces in sliding mode resulting in a 30% improvement in ROP as compared to conventional steel pipes.

The specially designed aluminium alloy made with copper, silicon and other elements offers high tensile and torsional strength as well as an enhanced strength-to-weight ratio. The material is lighter than conventional steel pipes and has a higher buoyancy. This means that the contribution of stiffness to normal force is reduced. The result: up to a 30% reduction in torque and drag as well as better weight-on-bit transfer.

OFDS President Peter Kaufmann sees tremendous potential in upgrading existing rigs with this solution: "FuchsRohr AluDrill pipe can extend the drilling depths of current installations and prevent cost-intensive upgrades. The pipe has a significant weight advantage, higher elasticity and a smaller bending radius than steel tubing. AluDrill pipes also manage the challenging friction forces in dog legs. At the same time, it offers excellent drilling characteristics and great safety in operation."

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World news

September 2018

Penspen alliance with Crestech secures PMC deal with Nigeria National Petroleum Company (NNPC)

Penspen and Nigerian engineering firm Crestech, have signed their largest contract to date after forming a strategic alliance in November 2016. The companies have secured a deal with the Nigerian National Petroleum Company (NNPC) for the provision of project management consultancy services across four gas projects in the Niger Delta region, with work already in hand.

The scope of services under the project management consultancy (PMC) contract includes, but is not limited to, the following four identified critical gas development projects: Oil Mining Lease (OMLs) 24 and 18 Joint Development, OMLs 26,30,32,42 and Makaraba Clusters Development, OML 13 Cluster Development, OML 35/62 Okpokunou/Tuomo West Cluster Development.

The scope of work covers project management services, as well as personnel support, throughout the duration of the planned gas development, initially expected to be completed by 2020. Peter O'Sullivan, CEO of Penspen, said: "Our partnership with Crestech allows us to deliver the full range of work required by NNPC in Nigeria and this highlights a positive step in our relationship and growth in the region. The strategic alliance allows the best of both companies to be brought together to deliver positive results for clients. "The seven gas projects will help NNPC to achieve its overall gas supply goals to support Nigeria's National Gas Policy (NGP) 2017. We look forward to working with NNPC and Crestech over the next four years."

The managing director of Crestech Engineering, 'Gbola Sobande, expressed his excitement to have Crestech play such a key role in moving Nigeria closer to its gas development goals. He stated that "jointly delivering a project of great significance to Nigeria, along with Penspen, will help strengthen the relationship between the two partners, while also further solidifying Crestech's position as a leading indigenous oil and gas engineering company that is recognised across Nigeria."

JDR and WILD WELL sign 5 year service agreement

JDR Cables Systems has been awarded a five year Long Term Service Agreement with Wild Well Control, Inc. The five year agreement, will see JDR design, manufacture and assemble intervention, workover and control systems (IWOCS) to be deployed in conjunction with Wild Well's 7Series subsea intervention systems.

David Nemetz, Director for the Americas at JDR, added: "This agreement is testament to our ability to establish trusted relationships with other industry-leading suppliers, not just in terms of technology, but in enhancing the way we work to deliver additional value for our customers. Establishing a long-term, sustainable relationship with Wild Well delivers on our partnership approach to our business as well as broadens our presence in deepwater markets such as the Gulf of Mexico and West Africa."

Woodside aiming to bring Senegalese oilfield into production by 2022

Australian oil and gas company, Woodside, is aiming to commercialise Senegal's first ever oilfield by 2022.

Detailing the "SNE Development - Phase 1" schedule on the final day of the Paydirt 2018 Africa Down Under mining conference in Perth, Mr Jamie Stewart, Woodside's Business Integration Manager for the Senegal Field Development, said a number of important items have already been ticked off in the lead-up to a Final Investment Decision (FID) in 2019 for the world-scale project, with a number of key decisions on the horizon.

These include the submission of the draft Environmental and Social Impact Assessment Report and the SNE Field Development Evaluation Report.

Woodside and its Rufisque, Sangomar and Sangamor Deep (RSSD) JV partners are currently evaluating tender responses for key contracts, and a number of cost reductions approaching 10% are being progressed and secured.

One of the looming decisions is the selection of the winning contractor for the Front End Engineering and Design (FEED) for the proposed use of a Floating Production, Storage for Offloading Facility for Phase 1.

Second half 2018 activities will include submission of the final Environmental and Social Impact Assessment and the field exploitation plan in the lead-up to FEED entry for the project.

The deepwater SNE Field will be Senegal's first oilfield and is expected to provide significant social and financial benefits to Senegal, with Phase 1 proposing to commercialise total recoverable oil of ~240 million bbls.

The development is projected to generate billions of dollars in direct revenue for the Government of Senegal over the first phase of the development. This includes fees and corporate income tax to be paid by the joint venture and revenues attributable to the Government under the Production Sharing Contract (PSC). In addition, the Government will receive revenue through State-owned petroleum company PETROSENS's equity participation in the development.

Agar Plantain exploration and appraisal well begins

Faroe Petroleum notes the announcement made by Azinor Catalyst Limited, the operator of the Agar Plantain exploration and appraisal well on the UK Continental Shelf (UKCS).

Catalyst confirmed that the Plantain exploration well spud at approximately 6:00 pm on 24 August 2018 using the *Transocean Leader* drilling rig. The well is expected to take approximately 28 - 38 days to complete and will be drilled to a depth of 1845 m TVDSS. The Plantain well will be followed by a contingent side-track to appraise the discovered Agar field. The total estimated gross cost of well operations is US$15 million.

Graham Stewart, Chief Executive of Faroe Petroleum, commented: "We are pleased to announce the spudding of the Plantain exploration well which is the first in a sequence of seven committed wells in Faroe's current exploration and appraisal programme. The next prospect is the Faroe-operated Rungne exploration well due to spud in September, located in Faroe's core area of the Norwegian North Sea."

FULL STEAM AHEAD

***Oilfield Technology* Correspondent, Gordon Cope,** reports on the recovery of North America's oil and gas sector.

In the wake of the global recession and subsequent collapse of oil prices in 2014, North America's oil and gas sector had been floundering. Recently, however, operators have once again found their even keel and the industry is sailing full steam ahead.

United States

According to the Energy Information Administration (EIA), proved crude and condensate reserves stood at 35.2 billion bbls, and proved reserves of natural gas stood at 241 trillion ft^3. Dry natural gas production is expected to average 81.2 billion ft^3/d in 2018, up over 10% from an average of 73.6 billion ft^3/d in 2017. The EIA forecasts that production will continue to increase, averaging 83.8 billion ft^3/d in 2019. Crude production, currently well above 10 million bpd, is set to push to 11 million bpd by the end of 2018, and 12 million bpd by the end of 2019.

The new crude production is emerging from a number of plays. The offshore Gulf of Mexico, for instance, is

expected to climb to 1.9 million bpd during 2018 – almost one fifth of all US production. In February 2018, the Stampede project came onstream. The field, operated by Hess, is 185 km south of the Louisiana coast. The tension-leg platform is designed to produce 80 000 bpd of crude and 40 million ft^3/d of gas from the deepwater Pony and Knotty Head fields.

The Permian basin, located in Texas, has been producing conventional crude for almost a century. Recently, explorers have targeted the multi-stacked shale plays using the latest well pad configurations, horizontal drilling and hydraulic fracturing technologies.

As a result, production in the Permian has skyrocketed. In 2010, output stood at 900 000 bpd and 5 billion ft^3/d of gas. By the middle of 2018, it had risen to almost 3.3 million bpd, and over 9 billion ft^3/d. IHS Markit, a consultancy, predicts Permian basin production will reach 5.4 million bpd by 2023. It also forecasts natural gas production will almost double to 15 billion ft^3/d, and natural gas liquids (NGLs) will top 1.7 million bpd.

In fact, the play is growing so fast that operators cannot find sufficient pipeline capacity to deliver product to market. The growth has all but used up space in pipelines, and drillers without firm transportation contracts are having to truck it to market. Some companies are idling their rig fleets, and others are shutting in wells. Drilled, uncompleted (DUC) wells in the Permian rose from 300 to over 3200 in the 12 month period ending June 2018.

New pipelines are on the way. In early 2018, Plains All American Pipeline (PAA) announced that it would build the 585 000 bpd Cactus II pipeline running from the Permian Basin to Corpus Christi, Texas. The US$1.1 billion project is expected to be completed in late 2019. PAA is also joining ExxonMobil to build a common carrier pipeline from several points in the Permian to the Texas Gulf Coast. The system would deliver over 1 million bpd of crude and condensate to the Beaumont, Texas region.

The Eagle Ford shale extends as a wide belt through southern and mid-Texas. It was one of the earliest unconventional crude targets, receiving much drilling attention from 2010 to 2014; by early 2015, production stood just shy of 1.7 million bpd. Although hard hit by the downturn, production has now started to rise again, and stood at 1.3 million bpd in early 2018.

Industry estimates place the recoverable reserves in the Bakken formation beneath North Dakota and Saskatchewan in the 18 - 24 billion range (although the US Geological Survey has a more conservative estimate of 8 billion bbls). Production reached a high of 1.2 million bpd in 2015 then dropped to under 1 million bpd before rebounding; the North Dakota Industrial Commission reported that oil production for the state reached 1.225 million bpd in April, 2018. Producers got a boost when Energy Transfer Partner's US$3.8 billion Dakota Access Pipeline (DAPL), began operation in early 2017, delivering 570 000 bpd to markets in the Midwest.

The US has several major unconventional gas plays, including the Barnett shale in Texas, the Haynesville in east Texas and Louisiana, and the Niobrara in Midwest states. The Marcellus formation, which occupies about 100 000 square miles of the Appalachian basin beneath Pennsylvania, Ohio and West Virginia, has been the major producer. The EIA estimates it holds at least 141 trillion ft^3 of recoverable gas. As of early 2018, production from the Marcellus and nearby formations surpassed 27 billion ft^3/d.

Canada

Canada has the second largest oil deposits in the world (over 170 billion bbls), and is the fifth largest oil and gas producer (4.5 million bpd of oil and 13 billion ft^3/d of gas). It sits adjacent to the world's largest single market for oil and gas, and is strategically placed to deliver hydrocarbons to both Asia and Europe.

The oilsands are the major component of growth in Canada's oil production. Although capital investment in the Ft. McMurray region of northeast Alberta has fallen from CAN$30 billion in 2014 to CAN$13 billion in 2017, production is expected to rise over the next several years, from 2.6 million bpd in early 2018 to as much as 4 million bpd by 2030. The growth will be due, in part, from 400 000 bpd capacity already nearing completion or under construction, as well as new construction, including Cenovus's Telephone Lake (US$6.3 billion), Imperial Oil's Kearl Oil Sands Phase 3 (US$5.9 billion) and Kearl Oil Sands Debottleneck (US$3.3 billion).

While shallow conventional fields account for the majority of Canada's natural gas production, unconventionals are now making major inroads. The Montney formation in northeast British Columbia (BC) and northwest Alberta has been the major unconventional play in Canada. The government and industry estimate that the play holds approximately 282 trillion ft^3 of gas and 12.8 billion bbls of crude and natural gas liquids (NGLs). Production has risen dramatically over the last several years, and now stands at 5 billion ft^3/d, approximately a third of Canada's total production.

The Montney also has significant liquids production. In May, 2018, Delphi Energy reported that a horizontal well in its Bigstone play in north central Alberta flowed at an initial restricted rate of 2.7 million ft^3/d raw gas, 1437 bpd of light oil, and over 100 bpd of NGLs.

In the mid-2000s, Newfoundland & Labrador's offshore crude production hit an all-time high of 360 000 bpd. Since then, the Hibernia, Terra Nova and White Rose fields have entered a long period of decline, with production dipping to below 220 000 bpd in 2017. The new Hebron field, which came onstream in late 2017, has lifted production to 235 000 bpd, and is expected to improve strongly. In the longer term, wildcat exploration in the Flemish Pass (located 150 km north from Hibernia), has indicated a resource potential of 12 billion bbls of oil and 113 trillion ft^3 of gas. In addition, resource potential of the nearby West Orphan Basin is estimated at over 25 billion bbls of crude and 20 trillion ft^3 of gas. The provincial government predicts production of 650 000 bpd by 2030.

LNG

Due to the abundant and cheap supplies of natural gas in the Lower 48, the LNG sector in the US has grown. In all, the EIA reckons that the US will have almost 10 billion ft^3/d of LNG capacity by the end of 2019.

- Cheniere Energy has four, 700 million ft^3/d trains operating in Sabine Pass, Louisiana, and has been shipping liquefied natural gas to consumers in Europe and Asia. Construction of two, 4.5 million tpy trains in Corpus Christi is expected to be completed in 2018, and first LNG shipments could happen before the end of the year.
- Freeport LNG expects its US$13 billion LNG plant and export terminal to start operations in late 2019. The three planned trains can each liquefy approximately 700 million ft^3/d. The project is located on Quintana Island, 100 km south of Houston.

- Permian Global Access Pipeline, a subsidiary of Tellurian, is developing the US$15.2 billion Driftwood LNG plant near Lake Charles, La. The plant would convert up to 2 billion ft^3/d into LNG.

Over the course of the last winter, LNG demand in Asia has reversed its price down-cycle, and major projects in Canada are now once again on the front burner. LNG Canada, led by Royal Dutch Shell, plans to build a four train plant with a capacity of up to 26 million tpy in Kitimat, BC. The project recently chose JGC Corp and Fluor to do the final engineering, procurement and construction. In May, 2018, Malaysia's Petronas (which cancelled its CAN$36 billion Pacific North West LNG Project in 2017), took a 25% interest in LNG Canada.

Problems

Although oil and gas exploration and development has not been curtailed by environmental opposition, trying to build national pipelines in Canada has been a lesson in frustration. After the NEB approved the North Gateway crude pipeline from Alberta to the marine terminal at Kitimat, BC, the federal government under Prime Minister Justin Trudeau essentially killed the project by announcing a moratorium on crude tanker traffic off the coast of BC.

When TransCanada attempted to repurpose part of its mainline natural gas system to crude transmission (the section running from Alberta to Ontario), then extend it to tidewater in New Brunswick, the federal government announced new regulatory considerations, including greenhouse gas emissions upstream and downstream of the project. The 4500 km, CAN$15 billion Energy East proposal, which would have delivered up to 1.1 million bpd from Alberta to the deepwater port of St. John, New Brunswick, was promptly cancelled by TransCanada.

In late 2016, the federal government gave the green light to Kinder Morgan's Trans Mountain expansion (TMX), a 60 year old line running from Alberta to tidewater in BC. The project will increase capacity from 300 000 bpd to 890 000 bpd. The project will also increase capacity at its Westridge dock in Burnaby, BC, to 630 000 bpd.

The newly-elected New Democratic Party (NDP) government in BC, which relies on the Green Party rump to remain in power, promptly came out against the ruling. Premier John Horgan announced that the provincial government would try to block the expansion with every means at its disposal. The mayor of Burnaby also strongly objected, refusing to issue routine civic permits to allow port construction. Kinder Morgan became so frustrated by the BC delays that they announced that, if a resolution was not forthcoming by 31 May 2018, they would abandon the project.

Similar opposition to pipelines has been growing in the US. The Keystone XL saga, for instance, sees no sign of ending. Originally proposed over a decade ago, the 1900 km line, designed to carry up to 830 000 bpd of crude from Canada to the Gulf Coast, was eventually refused the right to enter the US by President Obama. Even though the Trump Administration subsequently gave TransCanada approval in early 2017, it still faces opposition. Bold Alliance and the Sierra Club filed a complaint in a Montana federal court claiming that the presidential authorisation relied on outdated environmental assessments.

In March, 2018, a state judge temporarily halted construction on a Louisiana oil pipeline in order to prevent "further irreparable harm" to wetlands. Energy Transfer Partners (ETP), has been building the US$750 million Bayou Bridge extension from Lake Charles, La, to St. James, La. It passes through the Atchafalaya basin wetland. Prior to the beginning of construction, the US Army Corp of Engineers conducted two environmental assessments and found no significant impact. However, environmentalists and fishermen argued that the Atchafalaya basin is vital for flood protection and commercial fishing. The company appealed the decision, and the 5th US Circuit Court of Appeal agreed to lift that order.

Resolution

Governments and industry have been working to resolve issues. Two days before the Kinder Morgan's Trans Mountain Expansion deadline, Prime Minister Trudeau ordered the federal government to purchase the Trans Mountain pipeline system for CAN$4.5 billion. The purchase is temporary, and the government will sell the pipeline once it is in operation.

The Trump administration released a proposal to speed up the permitting of natural gas pipelines. The proposal would take away the authority of Congress to give approval to projects that cross national parks, and give it to the Interior Secretary, instead. It would also speed up the time states could take to issue 'section 401' water certificates as required under the federal Clean Water Act.

The major goal of the administration is to eliminate redundant reviews under various state and federal authorities. It also seeks to clarify who has ultimate authority over interstate pipelines. The state of New York, for instance, has denied section 401 certificates to the Constitution interstate gas pipeline, at odds with FERC.

If successful, the proposal would alleviate many of the bottlenecks in the pipeline approval process, as well as delays in a larger US$1.5 trillion infrastructure proposal. Environmental groups have come out against the plan.

The future

Global Data, a consultancy, estimates that almost US$120 billion will be spent on new oil and gas fields in the US and Canada between now and 2025. Of that, the US has the largest share, with US$76 billion, followed by Canada, at US$43 billion. While the lion's share will go to unconventionals, three of the largest single fields are in offshore Gulf of Mexico; Mad Dog Phase 2 (US$13.4 billion), Smith Bay (US$11.1 billion) and Horseshoe (US$6.5 billion).

New plays will also emerge. According to the latest figures from the National Energy Board (NEB), the Duvernay formation in Alberta contains 76.6 trillion ft^3 of marketable gas, 6.3 billion bbls of marketable natural gas liquids, and 3.4 billion bbls of marketable oil. Although there are only 500 wells drilled into the Devonian formation, operators have focused on the wet-gas region surrounding the Kaybob field in central Alberta, where operators are breaking even at CAN$40/bbl.

Much of the future of the oil and gas sector in North America is dependent on the price of oil. Production quotas between OPEC and Russia have stabilised the price in the US$50 - 60/bbl range, sufficient to make most unconventional plays profitable. Even if OPEC should once again decide to flood the market, North American operators have been working diligently to reduce break-even points to US$30, or below. Regardless, opportunities for growth abound in North America, and oil companies are eager to take advantage for the next several years ahead.

Forging a New Path

Jason Criss, INOVA Geophysical, USA, discusses recent advancements in cableless acquisition systems.

Second generation cableless acquisition systems have been available for more than 10 years and acceptance of this class of system continues to gain traction worldwide. In North America and Australia, the acceptance rate is nearly 100% as contractors, faced with permitting and other significant challenges, have shifted away from cable-based systems to new cableless architectures. This shift has come primarily because of the operational efficiencies that the cableless systems have over the older systems. Cableless systems are lighter, require less storage and transport space and have reliability factors that are equal or exceed the reliability of older systems. Third generation cableless systems are now available with smaller units that operate for extended periods of time. These newest systems open up further opportunities to modify operational strategies and have the potential to streamline jobs and the geophysical goals of seismic acquisition beyond what is being realised today.

Generation 2 cableless equipment

In the early 2000s, a second generation of cableless equipment started to appear on the market and was generally comprised of a unit for recording data, a separate battery pack and connectors for sensors and power. This style of unit was successful as contractors adapted to new field procedures and learned to take advantage of the benefits of the systems. Some of these systems provided quality control telemetry while others operated blindly. One benefit of this type of system was the fact that the survey design was flexible. Geophysicists were no longer constrained by cable lengths or active channel counts. Projects could be shot at any required group interval and any required density. A second benefit derived from cableless equipment is that it could be easily mixed with any existing system in a hybrid mode. Other benefits include ease of permitting, and the smallest

possible environmental footprint for seismic. Cableless systems could be deployed in a way that makes them unobservable to local populations. Cableless nodes can be used to augment cable system designs or used to gain data collection access to areas that were impractical for cable systems. This type of flexibility created a seismic recording system that allowed contractors to easily adapt it to nearly any requirement. System adaptability, along with reduced size and weight has become the foundation of field operation efficiency.

Figure 1. *Second generation recording node is shown without the battery and sensors. Weight is 1.7 kg, runtime is 30 days (with large battery and analogue sensors.*

Figure 2. *INOVA's third generation Quantum weighs only 650 g and has a runtime of 50 days.*

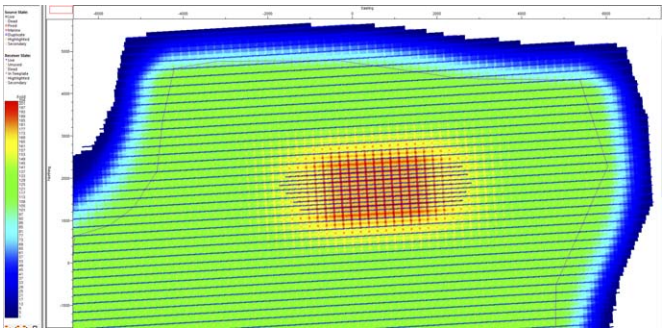

Figure 3. *A conventional survey design enhanced with third generation nodes to increase the fold in a specific area.*

Generation 3 cableless systems

In the last few years, third generation cableless systems have emerged that can be most easily and simply defined as a 'recording sensor'. Advances in electronic design coupled with the latest GPS technology and high sensitivity geophones yield a complete one channel recording system with sensor and recorder wrapped up in a unit, which is not much larger than a traditional 3C geophone. While some second generation nodes had some of these properties, it was not until the units were reduced in size that they could truly be considered third generation. The best examples of this third generation technology can now record seismic data continuously, once deployed, for up to 50 days, with dynamic range and fidelity equivalent to the best cable systems. Smaller, lighter units which record continuously with extremely long run times, create the opportunity to alter field acquisition strategies even further from the changes that have already taken place with older generation cableless systems.

Generation 3 and future system requirements

Receiver station densities have increased dramatically in the previous 10 years. A prerequisite of this capability was the need to manage much higher channel counts. The fact that each cableless recording device is an independent recording system means that each project has a virtually unlimited channel count. In addition, the size and weight of the units is much less than the size and weight of a similar cable system or even a second generation cableless system. 1 km² of a deployed cable system with a 25 m station interval and a 200 m crossline interval is estimated to weigh ~1200 kg while a similar deployment with a third generation node weighing in at only 650 g/station would weigh ~130 kg. This is a weight savings ratio of over 9 to 1 for a third generation system and a weight savings ratio of greater than 3 to 1 when compared with a second generation system. These levels of equipment reduction directly respond to the growing requirements to record more data with less effort and similar or lower costs. Smaller vehicles and fewer people on the ground allows crews to deploy and collect this type of system much faster. Further, the extremely long battery life of 50 days or more suggests new operational paradigms where crews simply roll deployed third generation nodes to a new station without returning the node to camp for data offload. A single node might occupy three or more individual stations as the shooting crew progresses through the project. Other strategies for data harvest are also possible. Since the units are very small a vehicle no larger than the current recording truck could be employed as a mobile data harvest centre, which continuously traverses the deployed spread gathering recorded data without the need for complex, costly and labour intensive radio telemetry networks.

As crews adapt their operations to these lighter, smaller, and longer duration third generation nodes, fewer crew members and smaller vehicles will be needed to perform the same job. This type of saving directly adds value to the task of gathering seismic data in any region. This value can be captured as lower cost or it can also be captured as more data for no increase in cost.

Hybrid crews

Cableless nodes have also introduced a new capability to seismic acquisition that is only now beginning to see common practice. The hybrid crew is a crew that deploys a single integrated central system but with a mixed architecture of ground equipment. One example of this would be a traditional cable crew that augments their operational flexibility with third generation nodes. Nodes can

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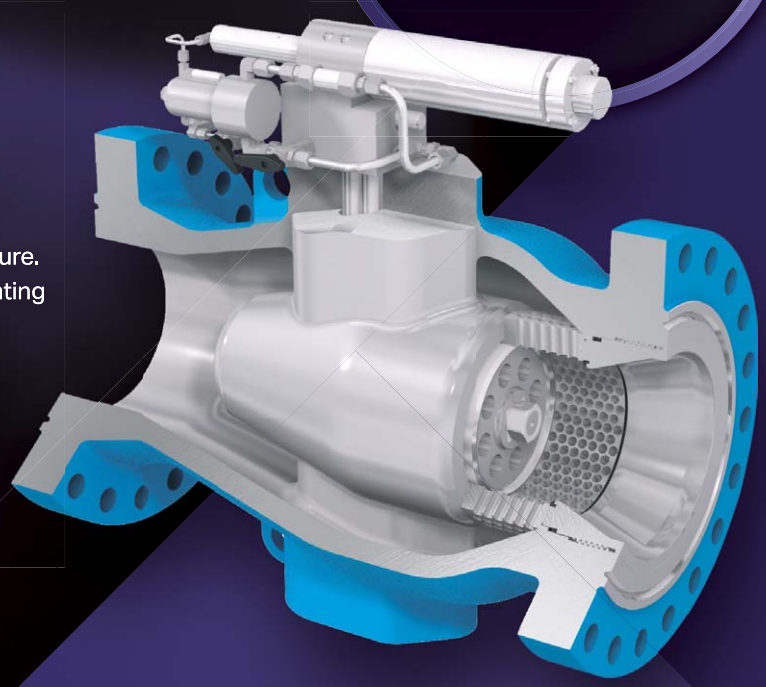

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be used to fill gaps in coverage or provide collection access to areas which are restrictive for cable systems. Early generation nodes have been utilised on commercial projects to add sampling in areas that are noisy. The most interesting aspect of the hybrid concept is that a continuously recording node can be added to an existing project at any time while the project is underway making adaptability one of the node's key benefits.

Figure 4. *A hybrid crew operating in 2017 in China. The project required the crew to collect seismic data in the mountainous area in the background. On this project the mixed cable system with second generation nodes was used to complete the project.*

Other concepts such as variable density shooting are also real possibilities. In some situations, projects will have multiple geologic targets which require different receiver station sampling. The node has the flexibility to deploy stations in denser patterns in some areas and less dense patterns in other areas. Modifications of this type of adaptation might be a survey design which samples less densely on the outer fringes of the project to capture apertures for migration and more densely near the centre of the project where high sampling rates are critical. Concepts like this can be used to reduce the overall cost of a seismic project without sacrificing sampling requirements.

Hybrid crews can be an appealing way for seismic contractors to begin transitioning to this new technology. It allows them to keep their familiar cable-based system with its real time data and noise monitoring capabilities while taking advantage of cableless nodes without taking major operational risks.

Conclusion

The role of cableless nodes has seen dramatic growth in the seismic acquisition market. In some regions of the world, nodes have nearly completely replaced the traditional cable system as the preferred method for gathering seismic data. This is due in part to the fact that nodes weigh less and occupy less space making crew operations more efficient. Third generation nodes will enhance this benefit with even smaller and lighter equipment. Nodes enable new concepts in seismic survey design and operational methods that are only just beginning to be explored. Virtually any surface pattern or density is possible and projects can easily be adapted or expanded while underway. This level of flexibility when compared with traditional methods of seismic acquisition will be ready to adapt to nearly any future system requirement.

FROM CPU TO GPU

Brad Tolbert, Stone Ridge Technology, USA, demonstrates the power of GPUs for reservoir simulation.

On 4 May 2018, the Italian energy company Eni issued a press release announcing a breakthrough calculation in reservoir modelling. One of the company's high-resolution deepwater reservoir models, with 5.7 million active cells, was used to generate 100 000 realisations, each with different petro-physical properties. The company ran all 100 000 models in 15 hrs on HPC4, its industry-leading supercomputer with each individual model simulating 15 years of production in an average of 28 minutes. The calculation is a prominent example of 'GPU-computing,' a growing trend in high-performance applications. Instead of using HPC4's 3200 CPUs, it used the machine's 3200 NVIDIA Tesla® GPUs. To achieve this, Eni partnered with Stone Ridge Technology, a US based software company that develops a GPU-based reservoir simulator called ECHELON.

The announcement demonstrates how energy companies can rapidly generate large amounts of data to help make important decisions. Calculations like this were previously deemed difficult or impossible to do because the asset was considered too complex or the simulation run times were so long that the project could not be completed fast enough for a business decision to be made. By utilising GPU technology for reservoir simulation, energy companies are able to carry out complex studies in short timeframes, thus allowing more information to be incorporated into the decision-making process. This ability is becoming more important as energy companies continue to look for ways to establish a strategic advantage in the industry.

Reservoir simulation codes, like ECHELON, model the subsurface flow of hydrocarbons and water in a petroleum reservoir. They allow energy companies, like Eni, to optimise recovery from their assets by simulating numerous 'what-if' scenarios for well placement and development strategies. ECHELON is built to run entirely on NVIDIA® Tesla GPUs using the CUDA® software, the same high-performance computing platform now powering the revolution in artificial intelligence, machine learning and 'Big Data'.

GPUs have traditionally been used for fast 3D game rendering. However, over the past decade they have been harnessed more broadly to accelerate computational workloads in areas of scientific computing including those related to oil and gas exploration

and production. Seismic processing was one of the first areas of the oil and gas industry to utilise GPUs. Today they are also heavily used in the machine learning processes that have become popular within the industry. GPU technology had yet to be fully implemented into reservoir simulation until a few years ago when Stone Ridge saw the opportunity. Implementing GPUs into reservoir simulation posed a difficult technical challenge due to the complex nature of the codes relative to other computations. Why go through the trouble of writing software for GPUs as opposed to more traditional CPU development? There are three good answers: performance, compute density and scalability. By embracing newer, GPU technology, modern algorithms and software design approaches, ECHELON outpaces CPU based codes in these three key areas of simulation.

Performance

Two processor metrics are of particular importance for performance. The first, FLOPS, measures how many calculations a processor can execute in a unit time period. The second, bandwidth, measures how fast data can be moved into the processor. Today's leading generation GPUs offer roughly 10x more FLOPS and bandwidth than CPUs in a chip to chip comparison. Figures 1 and 2 compare the evolution of these metrics on GPU and CPU over the last decade. Figure 1 illustrates the peak memory bandwidth provided by the latest GPU and CPU machines while Figure 2 provides the peak GFLOPS for each system. They illustrate how GPU technology has grown and outpaced CPU technology in recent years. All signs point to the continuation

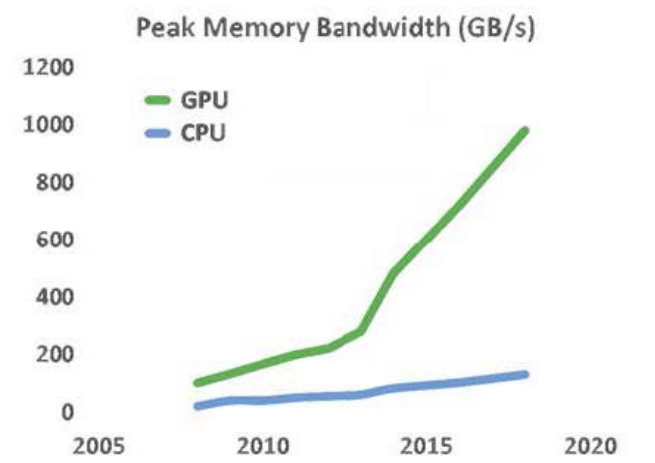

Figure 1. *Illustration of the the peak bandwidth provided by the latest GPU and CPU machines.*

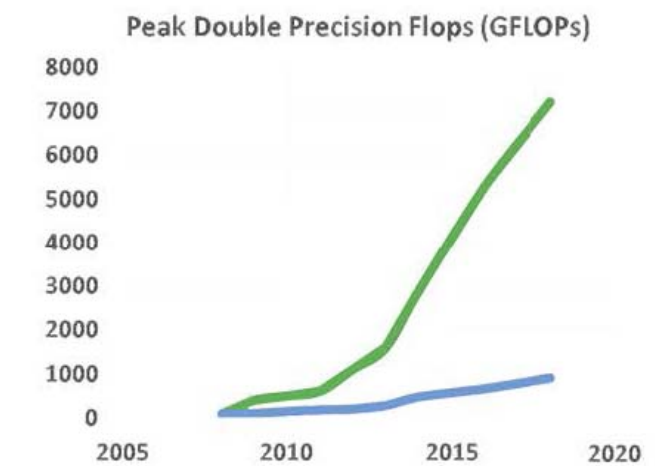

Figure 2. *The peak GFLOPS for CPU and GPU systems.*

of this trend in the future. In order to take full advantage of this technology gap, software needs to be written from the beginning so that all computations are completed on the GPUs. Previous industry technologies have tried to utilise GPUs by porting part of their code and creating a hybrid CPU/GPU approach. This has resulted in limited performance increases due to Amdahl's law and communication issues that arise between CPU and GPU systems. Stone Ridge Technology was the first to create a simulator that runs all significant computation on GPUs. The company's ECHELON simulator uses the full capability of GPUs to offer game changing performance, which will improve further as GPU technology advances into the future.

Compute density

Compute density refers to the physical hardware requirements required to achieve a given level of performance on a particular model. For example, using bandwidth as a proxy for compute ability we can make a comparison of compute density between GPU and CPU systems. A modern GPU server node can house 8 NVIDIA Volta cards with each having about 900 GB/s of memory bandwidth for a total of 7.2 TB/s in the compute node. By comparison the two CPUs in the node will offer about 200 GB/s. Thus, to match the 7.2 TB/s GPU bandwidth would require 36 nodes or two racks of computers. This density matters in real calculations. For example, in 2017 Stone Ridge and IBM demonstrated ECHELON's performance by running a billion-cell model on just 30 nodes in 90 minutes. By comparison other companies that have reported billion cell calculations have typically used thousands of nodes.

Scalability

Scalability is the ability to efficiently run large models without performance loss. Here again ECHELON outperforms traditional CPU solutions. Because CPU solutions need to find bandwidth in order to achieve performance they must scavenge it from many nodes in a cluster, hence the use of thousands of nodes for their billion-cell calculations. Using the example above where the memory bandwidth of a single GPU node was compared with its CPU equivalent, it was noted that 36 nodes would have between 16 and 32 CPU cores each for a total number of between 576 and 1152 cores. To accomplish the calculation the reservoir must be divided into roughly 1000 tiny domains. Each of these domains would need to communicate with its neighbours. The GPU solution by comparison would have eight domains, one for each GPU in the server node. Thus 8 domains for the GPU solution were used to solve the same problem as roughly 1000 domains for a CPU. More domains mean more communication between domains and thus decreased efficiency. GPUs have a two orders of magnitude advantage in the number of domains required to solve any particular problem. There is an additional, more subtle point here as well. The most efficient linear solver algorithms for reservoir simulation e.g. Algebraic Multi-Grid (AMG) are difficult to parallelise. Thus, they work more efficiently on GPUs where there are two orders of magnitude fewer domains.

Revolutionising current methods

Today's energy companies have increasingly more complex and critical issues that require a more detailed understanding of the subsurface due to higher stakes from deep-ocean drilling, the increasing complexity of unconventional reservoirs, and the increased computational requirements of ensemble methodologies. This leads to a high demand for ultra-fast, high resolution reservoir simulation. The massively parallel GPU hardware, along with careful implementation used by ECHELON allows scalable simulation up to billions of cells. This is all accomplished at speeds that enable the practical simulation of hundreds of ensemble realisations of large, complex models, all while using far fewer hardware resources than CPU based solutions.

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Reservoir engineers can develop more accurate, robust and predictive models when the time required for each iteration cycle is reduced by an order of magnitude or more. More detailed and higher resolution models provide engineers and managers with the ability to better understand the subsurface and to make more informed decisions about how to optimise production.

The process of studying the subsurface begins with geologists creating a model of what they believe the subsurface looks like and what concentrations of hydrocarbons exist throughout the model. Geologists use data from several tools such as maps, seismic imaging, and measurements from existing wells to create a detailed model of the subsurface. Companies spend a large amount of money obtaining this data and the process of building the model usually takes several months. Unfortunately, this detail is usually discarded in subsequent stages of processing.

Once the geologic model is created, reservoir engineers then use simulation to try to predict and optimise the production of the hydrocarbons over a certain time. This process usually takes several months as well. Due to the technology available in simulation, a large amount of the detail that is paid for and obtained by the geologist, is removed by reservoir engineers in order to achieve reasonable run times and limit the amount of time the engineer needs to spend waiting on simulations to finish.

The need for a fast, scalable reservoir simulator has grown in recent years due to greater reliance by energy companies on more compute intensive workflows in their business decision making. One of these compute intensive workflows is the process of uncertainty quantification for prediction. The uncertainty quantification process requires engineers to simulate hundreds to thousands of scenarios with each being assigned a probability. It is customary in the industry to describe this uncertainty in terms of low (P90), medium (P50), and high (P10). Due to the heavy computing power and time needed for these studies, engineers were previously required to shorten the projects by limiting the amount of runs and/or detail used in the study. Limiting the runs and detail used in the study lowers the accuracy and confidence a company has in using the data for business decisions.

Another compute intensive workflow that is used in the industry is the process of history matching. History matching involves calibrating the simulation model to account for observed data associated with the asset. This is achieved by varying the parameters of the model over several simulations until the output of the simulation matches the historical production data available. Like the uncertainty quantification process, history matching requires engineers to run hundreds to thousands of simulations with each simulation taking anywhere from a few minutes to several hours to run. Engineers are often required to find workarounds that limit the time and accuracy of the project to complete it in a reasonable timeframe.

Summary

The use of a fast, scalable reservoir simulator allows these studies to be completed much more efficiently while also keeping the geologic detail that makes them more accurate. This allows energy companies to be more confident about the data they are using for their business decisions while also saving costs by using fewer resources for the studies. The calculation done by ENI shows how energy companies can take advantage of these emerging technologies to efficiently produce large amounts of data to be used in their decision-making process, allowing them to create a more accurate description of the subsurface and providing them with a strategic advantage in production, acquisitions and their positioning within the industry. GPU technology is expected to continue to advance at a rapid pace while the reservoir analysis market is expected to grow at a compound annual growth rate of 4% through 2022.

Image courtesy of CGG.

ON TOP OF THE SPREAD

Jo Firth and Vetle Vinje, CGG, explore the challenges of imaging the shallow reservoirs of the Barents Sea.

The Barents Sea is a relatively new oil region which is expected to hold large petroleum resources.[1] Traditional marine seismic acquisition using wide spreads has struggled in this area and several oil companies have searched for solutions to obtain improved imaging. Lundin Norway AS is a key player in the Barents Sea and in 2015 it initiated a close cooperation with CGG which led to a new source-over-spread acquisition and imaging solution, known as TopSeis™.

TopSeis addresses the lack of near-offset data recorded in conventional towed-streamer acquisition by enabling the recording of short- and zero-offset data with the seismic sources located above the streamers. The split-spread streamer (hereon called SSS) data increases the illumination density (number of times a specific depth point is recorded) for both shallow and deep targets.

Lundin has a detailed knowledge of the geological and geophysical challenges in the Barents Sea and knows the importance of near offsets and high illumination for obtaining better images. Lundin and CGG worked in a symbiotic relationship with several cycles of comprehensive modelling of many survey configurations, field tests offshore Gabon and in the North Sea, and developing new processing and imaging solutions. SSS provides superior images, AVO and inversion, from the sea bottom to intermediate depths and below.

The Barents Sea challenge

Among the main reservoirs of the Barents Sea are karstified carbonates located at depths varying from 400 to 1600 m below the seabed, which require near offsets in order to be imaged successfully. The contrast in the velocity of these rocks with the overlying Triassic sediments is such that the critical angle is relatively small, meaning that the maximum offset recorded at reservoir level is in the range of 800 to 2400 m, depending on depth. Conventional narrow-azimuth towed-streamer seismic data lacks coverage at these near offsets, especially on the outer streamers, where the nearest offset may be 500 m.

Imaging in this area is further complicated by water-bottom-generated diffractions and multiples due to the hard, rugged seafloor with iceberg plough marks and pockmarks from gas seeping through the sedimentary layers. Increasing the near-offset fold is the key to improving the signal-to-noise ratio in the shallow section and to modelling the multiples accurately so that they can be removed effectively (Figure 1).[2]

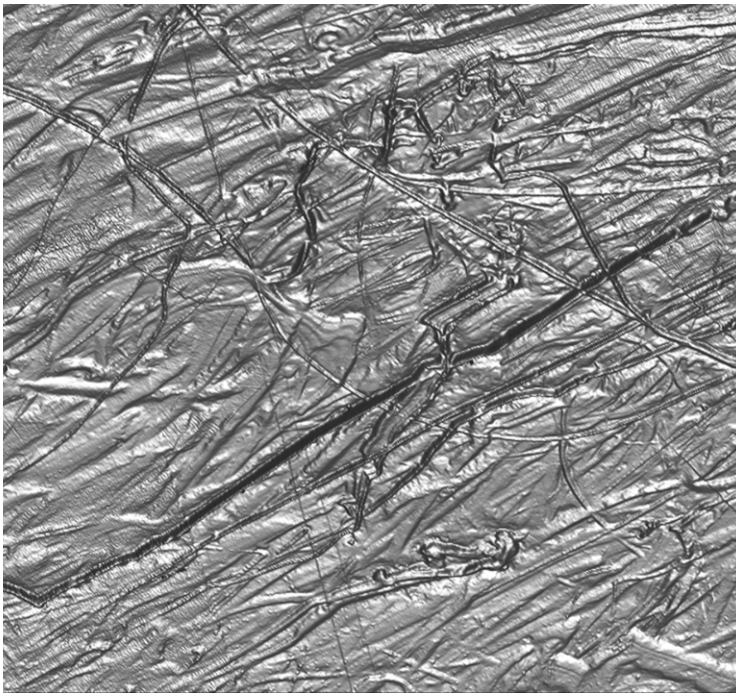

Figure 1. *Alta-Gotha water bottom, from Multi-Beam sonar (image courtesy of Lundin Norway).*

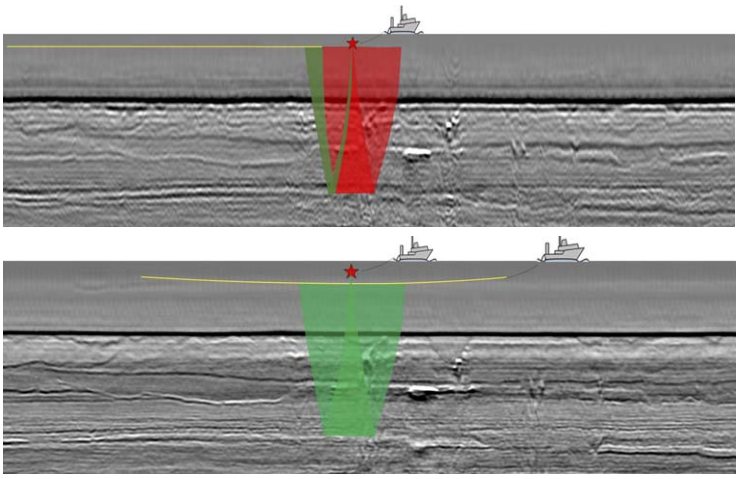

Figure 2. *In conventional acquisition (top) only a small part (in green) of the reflected energy cone is recorded, whereas with TopSeis (bottom) all the reflected energy cone is recorded.*

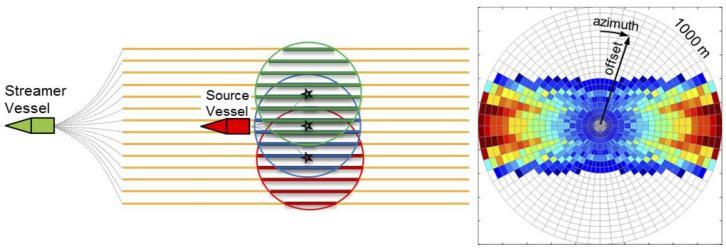

Figure 3. *TopSeis SSS marine acquisition configuration with offset/azimuth rose plot for offsets up to 1000 m.*

The proposed solution to this challenge was to acquire SSS data using two vessels, with the source vessel sailing behind the streamer vessel, directly over the spread.[3] Although there were some concerns about the feasibility of this option, CGG's experience with towing spreads deep and with variable profiles has delivered a wealth of operational knowledge. Further investigation revealed that it could be a practical solution if the streamers were towed deep beneath the source vessel, and that it would deliver the required fold and offset ranges (Figures 2 and 3).

Proving the concept

This solution required numerous risk analyses to be performed and operational strategies to be developed in order to ensure it was a practical, safe, efficient and operationally sound solution. In parallel with this, comprehensive 3D seismic modelling was performed to verify the processing and imaging feasibility of the concept. Various configurations, including streamer depth and profile, source vessel position and source and streamer separation, were evaluated to quantify the uplift of the proposed solution versus conventional acquisition.[3,4] This study showed that efficient acquisition of densely sampled data would be facilitated by towing the sources unusually wide and in a triple source mode (Figure 3).

One of the major operational concerns was the proximity of the source to the streamers. This required specific assessment of safe navigation procedures, the position of the source vessel, the length and towing shape of the streamer, and the effect on hardware and software of the close proximity of the streamer to the release of the pressure bubble. Following this review, an adapted emergency response plan was devised for the source and streamer vessels. Detailed analysis of the implications for processing were also required and resulted in a carefully calculated streamer shape for optimal imaging.

When all the known risks had been addressed a number of field tests were carried out to prove the concept, discover any unidentified risks and record some test data. The company's experience with deploying deep BroadSeis™ streamers[5] and operating multiple vessels in unusual configurations[6] provided the confidence to try this configuration and place the source over the spread. The aims of the initial field test were to move a source vessel over a deep-towed spread, confirm the expected response of the nearest hydrophones and record some data to use in development of the processing techniques and algorithms that would be required. Figure 4 shows an example split-spread shot record. The next tests were designed to test the towing width limits of the sources and any engineering required for stable wide-source towing over an extended period of time. The third stage of testing was to acquire a 2D line from deep to shallow water, to check the limitations of the technology with relation to water depth and to enable a direct comparison between this SSS data and a conventionally acquired broadband 2D line and so evaluate the potential of the solution.

New operational procedures were developed for line turns, escape route and emergency protocols as well as communication and navigation procedures. Additional crew members were placed on the bridge and on the navigation desk to ensure vigilance at all times, with visual displays set up on both seismic and support vessels so that all could

see their relative positions and the shape of the streamers in the water. The final proof of concept was a 3D field trial over the Frigg-Gamma field, where the geology demonstrates similar challenges to those of the Barents Sea.[3]

Loppa High survey

Following this 3D field test, only minor adjustments were made prior to the full-scale 3D survey acquired for Lundin Norway in the Barents Sea. This approximately 2000 km^2 survey was acquired between July and September 2017 with no recordable HSE incidents and only 1% technical downtime, justifying the planning effort involved.[7]

The use of 14 densely spaced streamers and triple sources towed wide delivered a crossline bin size of only 8.33 m with a sail line separation in line with a conventional survey. The use of blended source technology enabled the sources to be activated at 8.33 m intervals (25 m per source) and combined with placement of the sources over the deep-towed streamers resulted in excellent near- and zero-offset coverage with ultra-high fold. The illumination density was a maximum of 17 times higher in the shallow part of the section than achieved by a conventional configuration, decreasing to five times higher at depth. Figure 5 shows the trace distribution benefit of wide-spread sources over the streamers compared to a conventional survey.

Processing of this data set is still ongoing, but already many of the expected benefits are becoming apparent. Recording of the complete direct arrival enabled accurate positioning of the source and receivers and this, combined with the carefully designed slanted streamer shape and dense streamer separation, delivered good notch diversity for deghosting. The deep-towed near offsets resulted in less swell-noise and generally improved signal-to-noise ratios. Split-spread offset distribution including negative offsets, combined with near- and zero-offset coverage, smaller bins and high fold, delivered higher-definition multiple models including diffracted multiples, which, in turn, deliver improved multiple attenuation.[8] Velocity and anisotropy model building has been improved by full 3D recording of the curvature of seismic events, which should provide better imaging. The results from this survey, with small bins and high fold, are already showing a higher degree of both spatial and temporal detail and resolution than the conventional data, as shown in Figures 6 and 7.

Wisting survey

Following the acquisition of the Lundin survey, a small 24 x 3 km area was acquired over the Wisting field in the northern part of the Barents Sea for further evaluation of the technology, and to test additional acquisition parameters. The imaging challenges at the Wisting field are due to the very shallow Jurassic reservoir at approximately 250 m below the seabed. This area covers three wells, with the Central Well (7324/8-1, where the Wisting discovery was made) being located in the centre of the test area. This well was used in evaluation of the AVO of the SSS data. The synthetic data set used in the original source-over-spread modelling tests in 2015 was based on the geology of this area.

As in the Lundin survey, the initial results over Wisting are also encouraging (Figure 8). The vintage line is not coincident with the SSS line, but they intersect at the Central Well. Again, the SSS data shows greater resolution and improved S/N, providing details in the reservoir not visible on the vintage (2009) data. Notice that the 2009 data has subsequently been re-processed, resulting in improved imaging so the detailed comparisons on this field are still ongoing.

Having observed a considerable improvement in imaging in the shallow targets on Wisting, AVO analysis was performed on the SSS data set to investigate the improvements obtained by the good angle range recorded. Four angle stacks, (0 - 10, 10 - 20, 20 - 30 and 30 - 40°), were the input to the AVO analysis. As expected, AVO prediction was improved by the increased fold and the direct measurement of the intercept from recording zero-offset data. The SSS data showed a good match to the well data and also gave consistent AVO results, with both the seismic and well data showing negative intercepts and gradients. This creates a positive AVO product (intercept x gradient), indicating a Type 3 AVO response, which may indicate hydrocarbons, although other lithologies can also give this response.

A full deterministic elastic inversion of the four angle stacks was also performed, using amplitude-filtered well logs as an initial model. The outputs from this seismic inversion are 3D acoustic and elastic impedance volumes which should reflect the rock physics properties of the target sands. A high correlation between the inverted attributes and well logs at both exploration wells was observed. In addition, a distinct lateral variation in absolute Vp/Vs ratio amplitudes (from high to low values) is observed when moving towards the structural highs on the Top Stø formation (Figure 9). This is believed to be an indication of the transition from oil to gas in the reservoir. Several smaller prospective anomalies, as indicated by the red arrows, can also be observed, which should help in the positioning of future development wells.

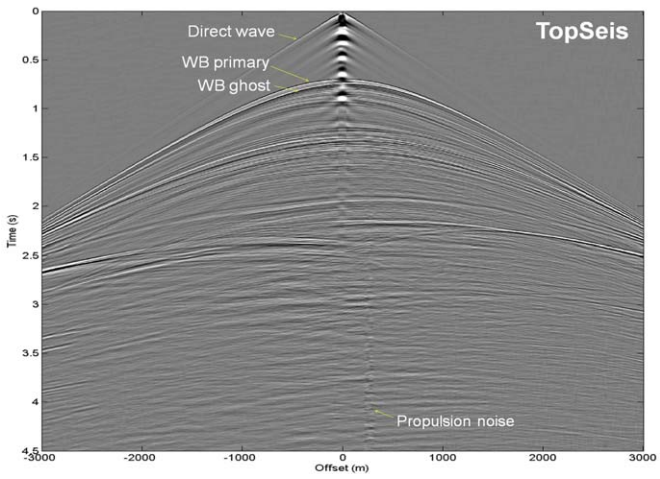

Figure 4. *TopSeis split-spread shot showing direct wave and receiver ghost.*

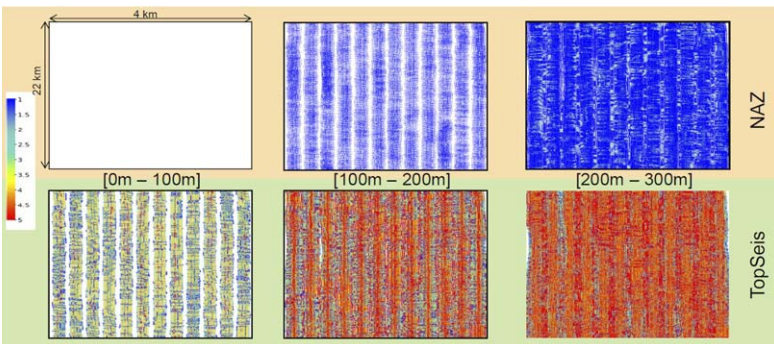

Figure 5. *Near-offset distribution for a conventional survey (top) compared to an SSS survey (bottom).*

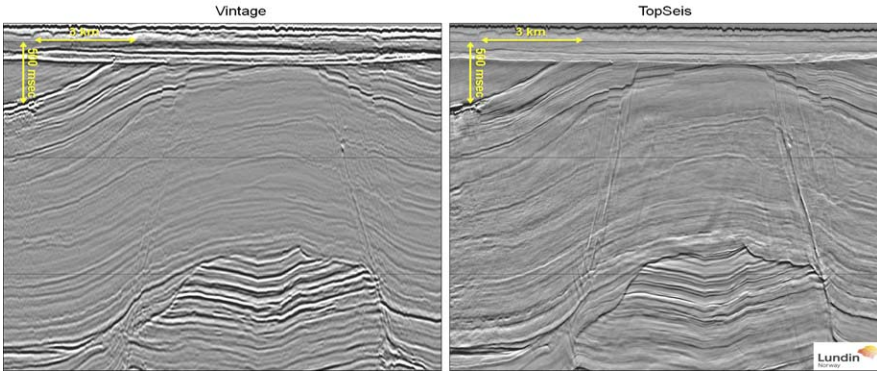

Figure 6. *SSS versus legacy comparison over Loppa High (data courtesy of Lundin Norway).*

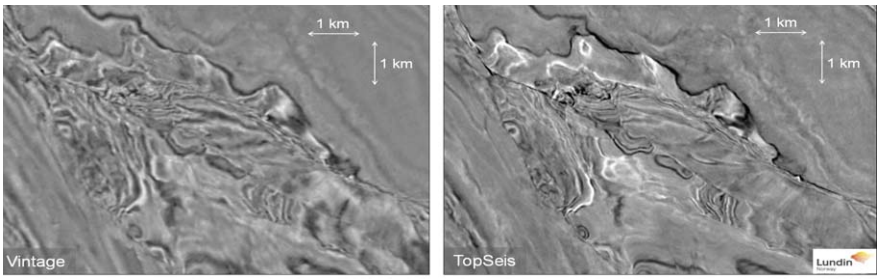

Figure 7. *Comparison of timeslices at 1450 msec (image courtesy of Lundin Norway).*

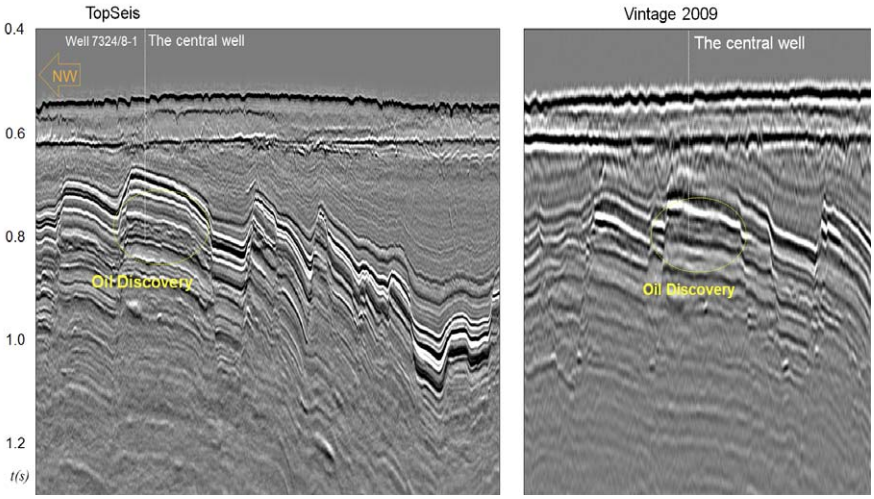

Figure 8. *Comparison of TopSeis with existing vintage data over the central well on Wisting (image courtesy of OMV and CGG Multi-Client & New Ventures).*

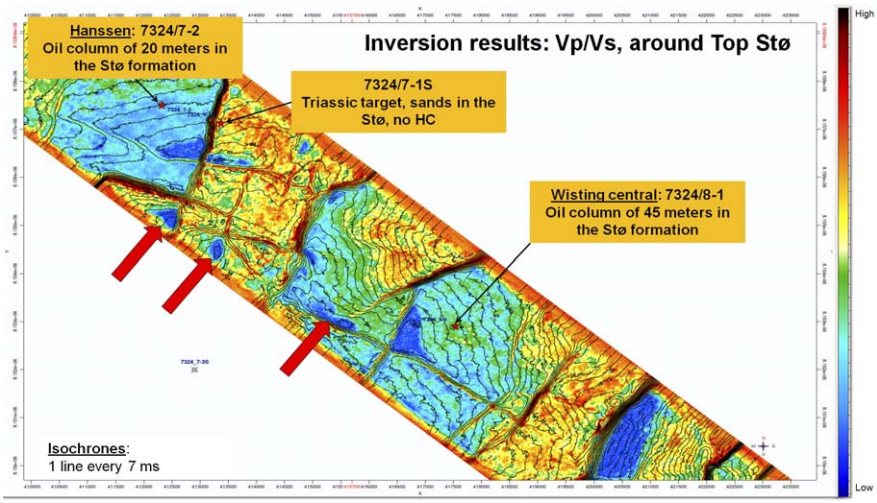

Figure 9. *Elastic inversion result, Vp/Vs around the Top Stø formation (Image courtesy of CGG Multi-Client & New Ventures).*

Conclusion

Initial results in the Barents Sea using the source-over-spread solution have been shown to be very promising, delivering the hoped-for improvements in resolution and illumination as well as clear and credible AVO and inversion results, consistent with the geology. Although designed for the Barents Sea, this solution will have applications in many other areas of the world, where improved near-offset coverage and high spatial resolution is required. The improvements are not restricted to the shallow section, but also extend down to at least 3 sec. Where long offsets are required in addition to the short and zero offsets, sources can also be deployed on the streamer vessel. This might be useful, for example, in areas where short offsets are required for demultiple, at the same time as long offsets are required for imaging deeper targets and for Full Waveform Inversion.

Seismic modelling prior to acquisition enables the optimisation of acquisition parameters required for the imaging challenge at hand, and ensures the correct solution and the best possible subsurface images and data for reservoir characterisation. Close collaboration between geologists, geophysicists and operational experts, combined with the continuous improvement process of modelling, risk assessment and testing, is also fundamental to obtaining successful results.

Acknowledgements

The authors would like to thank Lundin Norway AS and CGG Multi-Client & New Ventures for giving their permission to publish this article and to show the data examples.

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James Wallace, Polarcus, UK, considers whether towed streamer acquisition can be effective in a heavily congested area.

A MARINE MISSION IN THE MIDDLE EAST

The marine seismic industry is always changing and adapting. Technology is advancing, safety is improving, surveys are becoming more efficient, the carbon footprint of vessels is reducing, the number of seismic vessels is fluctuating with demand, and the areas of high seismic activity are continually moving.

Small to medium size E&P companies, as well as the nationals and majors, are embracing new innovations and utilising lower day rates to replenish their reserves portfolio. With an ever-increasing global population, and hence growing demands for fossil fuels, governments are thinking about their reserves-to-production ratios and the national security and economic stability that comes with it.

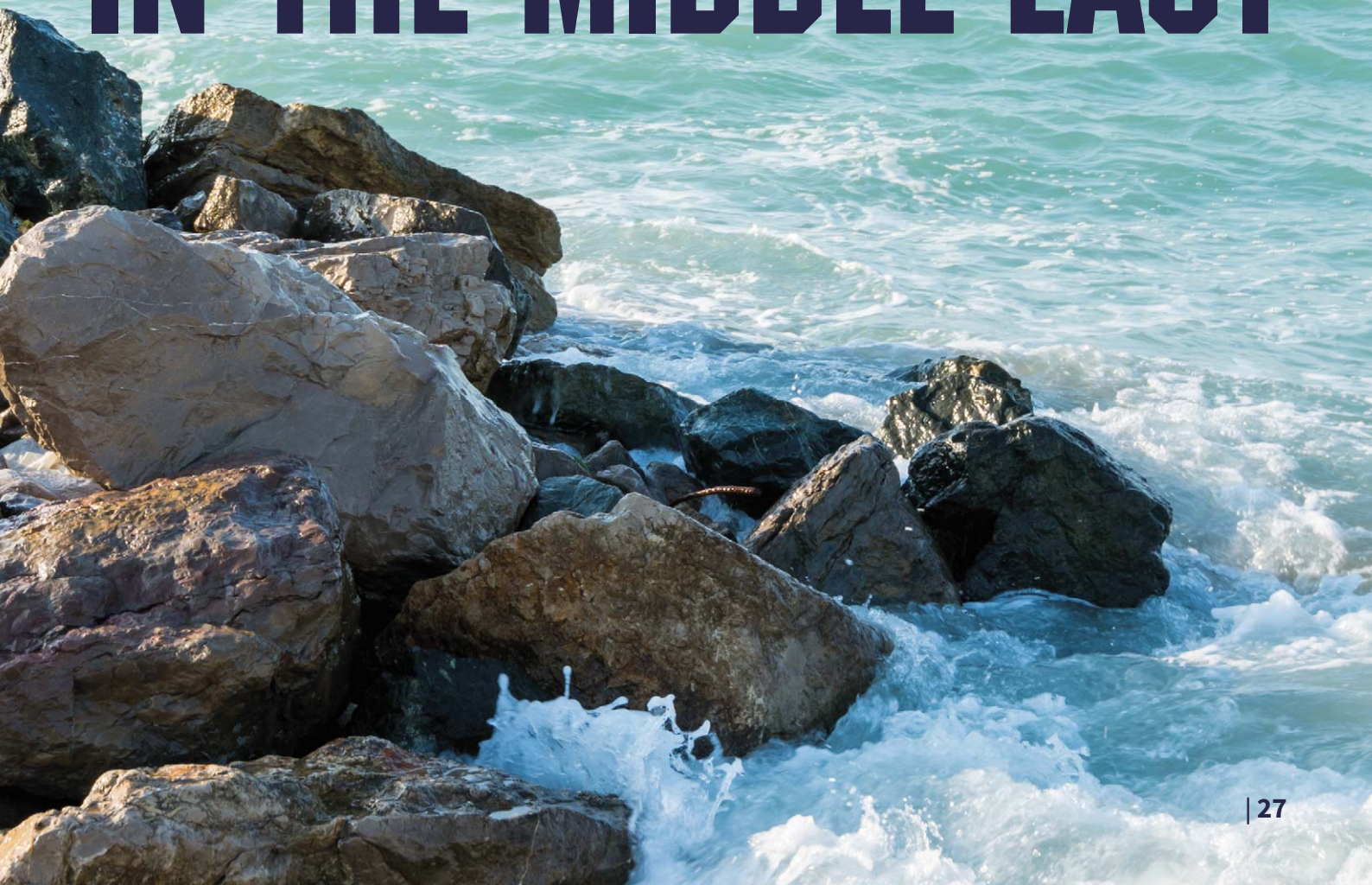
A few years ago, when the oil price was hovering around US$100/bbl, high latitude and deepwater discovery surveys were hot topics of conversation (in addition to the usual North-West Europe/West Africa seasonal cycle). With the fall in the price of oil came the focus on 4D surveys to maximise existing field potential and, in the face of a very tight market, the revisiting of existing datasets to improve them through fresh acquisition or reprocessing.

Middle East

One region that could be historically considered as the industry's 'sweet spot' is the Middle East. From the middle of the last century, oil exploration has brought about significant social, political and economic developments. Geopolitical stability in some of the countries that make up the Arabian Peninsula has led to heavy, and fruitful, investment from international E&P companies.

The United Arab Emirates, in the top ten largest proven global crude oil reserves (World Energy Council Oil World Energy Resources 2016), is one such country. Formed in the early 1970s, the federation has dramatically evolved into a well-known trading and tourism hub. With oil exports making up around a sixth of the gross domestic product (MOE Annual Report 2017), the UAE is a key contributor to global strategic petroleum reserves.

Nestled between the Al-Hajar Mountains, which tower nearly 2 km above sea level and span north-eastern Oman and the eastern UAE, and the serene waters of the Arabian Gulf, is the seventh Emirate, Ras Al-Khaimah. The fourth largest Emirate, making up approximately 3% of both the total land area and total



population, it is a relatively under-exploited region in comparison to some of its neighbours.

The Ras Al-Khaimah Sub-basin contains continental clastic and evaporite shelf carbonate sediments transitioning to complex faulting found in the foreland basin. The Lower Cretaceous formations found here are part of the famous Thamama Group, which is one of the largest oil reservoirs in the world. This area has had some exploration and production activity dating back to the 1980s. Two fields have been active: Saleh was one of the main producing gas and condensate wells in UAE, while the other, RAK B, has proven oil reserves.

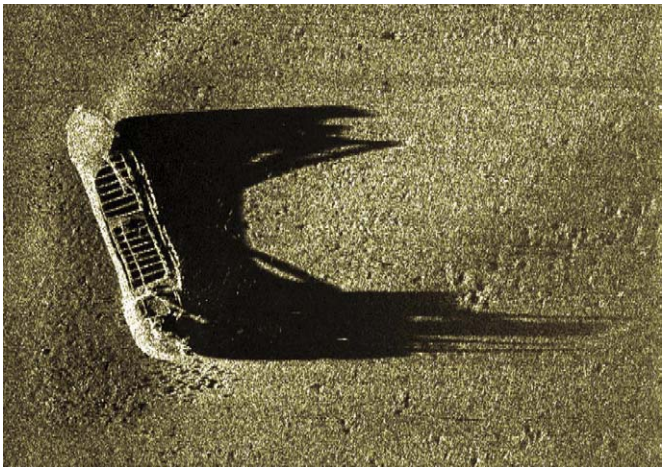


Figure 1. *Shipwreck from a Bathymetry survey.*

Figure 2. *Unmanned platform in the Saleh Field.*

Figure 3. *The Polarcus triple source configuration.*

There have been a few surveys offshore Ras Al Khaimah: 2D exploration lines and a 3D survey over each of the main fields, RAK-B (ocean bottom cable) and Saleh (towed streamer). In 2017, Polarcus was challenged to come up with a viable solution, both operationally and geophysically, to acquire a high-quality dataset as safely and efficiently as possible to improve on the existing data and cover the entire width and breadth of the Emirate's waters, from water depths of 80 m up to the coastline's 15 m contour, in preparation for a 2018 licensing round. Achieving this was to be a challenge for even the most seasoned members of the project team.

Methodology

A suite of Polarcus geophysical tools had to be incorporated including survey design (for a tailored acquisition strategy), XArray™ acquisition (to ensure optimal spatial sampling), multi-vessel operations (to maintain milestone deadlines), broadband processing (to provide high temporal resolution), continuous recording (to maximise inline fold and trace density for uplifted signal to noise) and infill management (to achieve lateral resolution requirements).

The decision was made to run this project slightly differently to a conventional arrangement of client and contractor, but rather as a collaboration. This is where Polarcus and RAK Gas partnered together on the survey and both sides had their own client project managers. This gave the benefit to RAK Gas of Polarcus running the project, utilising the company's expertise on marine seismic operations, and the geological expertise and local support from RAK Gas, while sharing the cost and risk.

Before the discovery of oil, the region's traditional income was fishing, and this is still an industry that is well respected and embedded in the culture. The area is very busy with fishing activity, from small dhows to larger trawlers. Fishing is not just an income for the residing populace but a core part of the local community, and as with many areas the company's boats work in, seismic operations are uncommon, in this case just a handful over a 30 year period, and therefore unfamiliar to the fishing community.

Another major concern for the operation were the many shipping lanes that run through, or in close proximity to, the survey area, especially traffic in and out of Dubai and Abu Dhabi. There are three ports in Ras Al Khaimah, the main one being Mina Saqr. The anchorage areas used by this port, and therefore the traffic separation scheme, for their ingoing and outgoing ships, were situated within the survey extents.

There are the shallow waters along the coastline with hidden wrecks scattered across the sea floor. The maximum draft of the seismic vessel is 7.5 m, and the deepest section of the towed equipment is 10 m, and standard safe operating procedure is to maintain 15 m clearance under the vessel and 5 m under the equipment. The coastline was without reliable bathymetric data, apart from in specific areas used by RAK Ports.

Surface obstructions added to the survey risks including seven platforms located in the Saleh field, one platform in the RAK-B field, surface marker buoys (for a wreck, well-head and shipping lane), and a single point mooring turret used by RAK Port.

To mitigate the HSE and operational risks, it was important to design a survey that would be safe and efficient to acquire but to also image the Cretaceous carbonate layers and deeper Jurassic reservoirs. The result was a triple source towed streamer acquisition set-up with nominally six streamers, 112.5 m apart and 6 km in length. This created an 18.75 m cross-line sample interval to image the 30˚ dips found in the foreland fold and thrust belt.

The spread width was maximised to cover 337.5 m of the subsurface with each pass. With dual sources, the equivalent spread would be 8 x 75 m (to match the 18.75 m cross-line sampling), which would have 37.5 m less coverage with each pass and two additional

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streamers deployed. The triple source configuration reduced HSE exposure, reduced acquisition time, and reduced operational exposure during complex in-field operations.

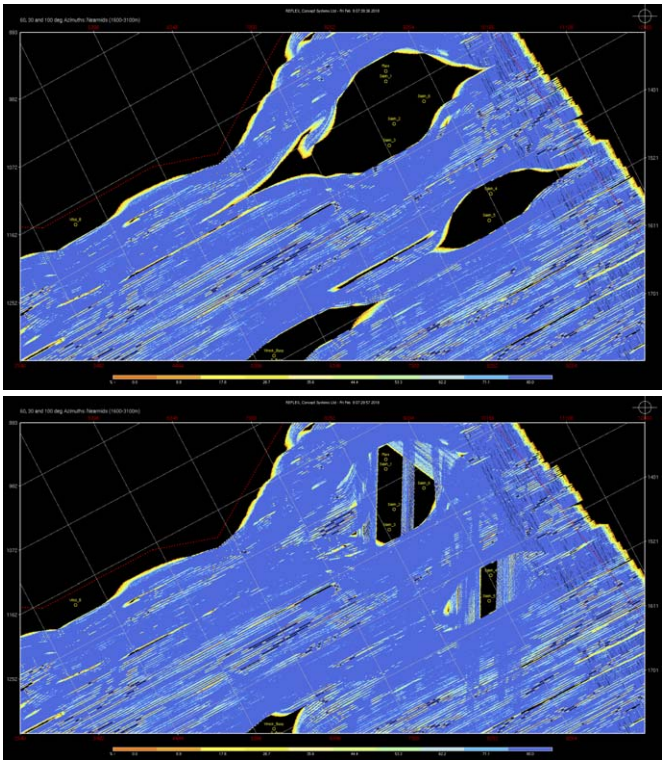

Figure 4. *Before boxing-in operations (top); After (near-mids offset group)(bottom).*

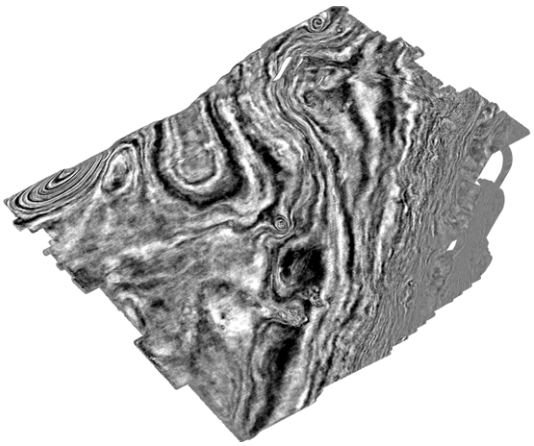

Figure 5. *Full fold QC cube time slice 1.5 seconds.*

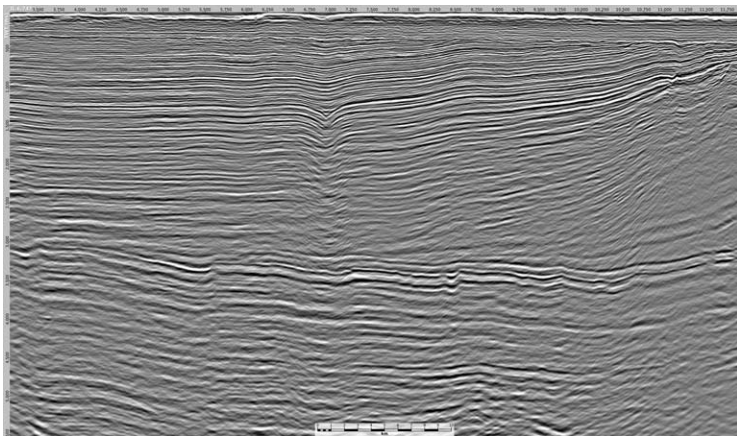

Figure 6. *PreSTM onboard priority processing stack.*

Source array shot interval was set to 12.5 m to maintain high inline fold and allow for 5.4 sec. of uncontaminated data below the water bottom so that the primary targets, between 1.0 to 4.0 sec. two-way time, were outside of the blended zone.

Operations started in the deeper water, in the swath of lines that contained the Saleh and RAK-B fields. The original plan had been to acquire this area with six streamers and then shoot the remainder with eight streamers, however operational constraints steered the decision to acquire the entirety of the survey with six streamers. The streamers were set to 12 m deep, with sources at 5 m, to maximise the low-frequency content of the data.

Simultaneously, a bathymetric survey of the coastal 15 m contour was being acquired by two multi-beam vessels. Nine shipwrecks and 88 boat wrecks were observed within the survey limits, with only one shipwreck deemed too dangerous for the streamers to pass over (11.5 m below sea surface). The bathymetric survey was completed in time for the seismic vessel to be able to reconfigure the streamers to 8 m deep (to maximise shallow water coverage) and commence the shallow water swath.

The seismic vessel then reconfigured to 4 km streamers to improve vessel manoeuvrability during close pass operations and acquired oblique line passes around the surface obstructions in the Saleh field. The minimum distance between outermost in-sea equipment and obstructions was 100 m, meaning close pass approaches had to be carefully planned. *Polarcus Alima* completed 35 close pass operations in just seven days, closing the gaps in coverage. This was perfectly executed without incident despite the high levels of fishing activity, nine static obstructions and being restricted along one side by an international border. This included two high risk passes directly through the middle of the field with platforms either side.

Finally, and with close coordination with the Harbour Master RAK Ports and his team, the last swath was designed to acquire data at an optimal azimuth along a no-go zone containing surface obstructions next to Mina Saqr Port, with temporary anchorage areas set up for the port traffic.

Outcome

Certain factors outside of the company's control resulted in the termination of the survey before the easternmost area was completed. Therefore, the question remains: can towed streamer acquisition be effective in a heavily congested area?

This, of course, will very much depend on the perspective of the individual and the specific circumstances. For this survey, it can be confidently stated that *Polarcus Alima* completed the objectives that were laid out before survey commencement: to acquire a high-quality dataset that images the very complex geological setting (large thrust faults and the presence of salt), with no incidents harming people or the environment, maximising coverage around the installations and in the shallow water zone – all within the allocated time frame and project budget. In an area where expensive ocean bottom seismic is arguably better suited, the 2017 Offshore RAK 3D XArray survey shows that towed streamer acquisition can prevail.

In addition to the onboard Polarcus PreSTM product, an advanced time processing sequence will be utilised on the 2017 data and the vintage 3D, which infills the obstructed areas. To be run in the London office of DownUnder GeoSolutions, the workflow includes deblending, source and receiver deghosting, shot-by-shot near-field derived source designature, 3D shallow water demultiple, multi-dimensional interpolation and regularisation, and anisotropic Kirchhoff pre-stack time migration.

NEW KID ON THE BLOCK

JJ Herman, Shear Bits, Canada, discusses recent hybrid technology advancements and their application through case studies.

One could argue, that the level of economic pressure and competition on the oil and gas drilling industry has never been so high. At the pointy end of this stick is where the drill bit resides and where all these economic pressures of risk and reward converge. No single role compares to the low cost of renting or purchasing drill bits versus the value that this product and service can contribute to the economic benefits of the drilling operation. This key factor is what drives the extreme pressure on drill bit development and where the results of the performance of drill bit technology have such a clear outcome of win or lose. Since all components of a drilling operation bear their weight on the drill bit, it often takes the blame for factors entirely outside of its control. There are more opinions and emotional loyalties tied to drill bits than any other component sitting around the drilling rig. Competition is fierce with all the largest service companies having their own drill bit line and matching those drill bit designs to their own bottom hole assembly components. One bit holds the title on each interval of each well and the other bits are trying to steal that title away – like a heavyweight title fight every run. This is where the concept of merging technologies together and creating new ways to fracture rock was born and where hybrid drill bit technology has been emerging from for decades.

New hybrid on the block

The latest hybrid design introduced back in 2013 is Pexus™ Hybrid technology from Shear Bits. Since its introduction, Pexus technology has taken on an evolutionary adaptation moving at a higher rate than any hybrid technology preceding and the platform of flexibility to drastically adjust the build specification in such a short time frame is unmatched. Utilising two separate cutting structures, each on their own radial and axial plane, and own fracturing mechanisms is what gives this technology a unique geometry. Features and changes can be applied to the final build specification within days or minutes depending

on the adjustment required. The finest of adjustments between the relationship of these fracturing components drastically changes how the energy being applied by the drilling rig is transferred into the rock. This level of precision manufacturing and finite adjustments are what has made the challenge so great to overcome. Workload, shear length, heat, force, helical drilling path, downhole pattern, wear relationship, cooling demands, cleaning demands, and fracture efficiency are all factors and change with every adjustment. The challenges begin with the analysis of the application, which demands skilled and experienced individuals to decipher and define the root causes and critical aspects of the drilling environment. There are many critical components to the design strategy consisting of extreme demands on the design software platform, CFD algorithms and execution of the engineering team. These high standards continue through to the highest quality machining capabilities and programming experience followed by a very high level of quality controls and finish manufacturing processes. Using only leading-edge materials and components can this technology be produced and implemented. All these factors lie on the need for strong communication and team effort shared between the drilling operator and sales and application teams

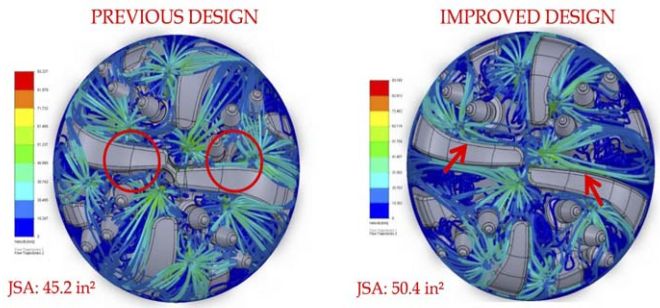

Figure 1. *New CFD platform example.*

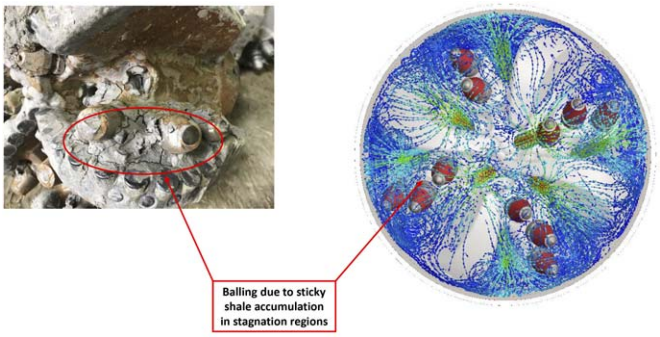

Figure 2. *Overcoming the challenge – CFD balling.*

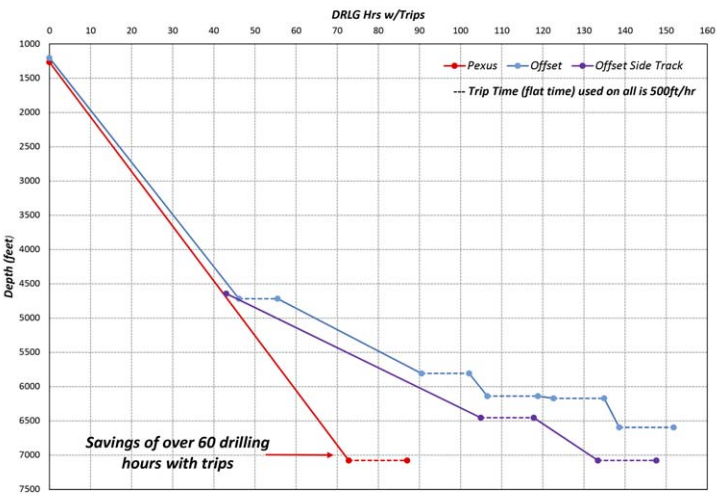

Figure 3. *Eastern Europe case study graph (12 ¼ in. interval).*

of the drill bit company so this whole process has a strong foundation to build from.

Overcoming the challenge

Shear Bits realised how important overcoming these challenges would be, which led the company to make the investment and commitment to completely reinvent its engineering and manufacturing processes from the ground up. This transformation included developing and implementing API Q1 certification (April 2016), moving to Creo Pro-E design software (February 2017), training new individuals with varying backgrounds to mould into bit designers who could collaborate more closely with the engineering team, creating a Quality and Technology Director position in the organisation, developing new sophisticated design models and writing a proprietary design manual. Elevation of the technology also required collaborating with specialists and universities to develop CFD modelling, working jointly with scientists and manufacturers to develop material grades and compositions unique to their design needs and attaining patent certification of the Pexus Hybrid family.

Case studies

Eastern Europe

An operator is drilling wells consisting of multiple hole sizes to reach depths ranging from 15 000 - 18 000 ft MD. The intermediate intervals are drilled in 12 ¼ in. and 8 ½ in. bit sizes and each interval most commonly takes multiple bits to complete each section.

The 12 ¼ in. section has an abrupt challenging transition at the mid-point of the interval which has demanded a bit trip on all the prior wells. Conventional PDC designs have been run on the top section, having trouble with balling in challenging shales and were not successful drilling the sand and carbonate transition at the mid-point. Therefore, rollercone tooth bits have been the primary choice for reaching the mid-point and being sacrificed in the transition. If the transition is not drilled entirely by the first tooth bit either a second rollercone insert bit is required or a PDC is sacrificed in a short run before another PDC can be run. The bottom end of the 12 ¼ in. interval requires multiple PDCs to reach casing point due to hard transitional carbonate drilling with low penetration rates resulting in long on bottom drilling hours. The first Pexus Hybrid design was run on a conventional motor BHA for this interval and replaced the rollercone tooth bit and a minimum of one additional rollercone and two PDC runs (4 - 6 total bit runs) while improving penetration rate by 22%.

The 8 ½ in. interval consists of hard dolomite with presence of abrasive sand lenses throughout with high bottom hole temperatures. Additional drilling challenges include a high mud weight environment and interbedded transitional drilling. The conventional PDC bits are pulled with impact damage to PDC cutters as well as wear and high thermal abrasion. Wear conditions often start in the centre of the bits continuing over the nose and shoulder to gauge. Chipping and breakage begins on the nose and continues through the shoulder to the gauge region of the profile after only 30 - 60 hrs of drilling. Multiple six (double row), seven (double row), eight and nine bladed conventional PDC designs have been utilised to drill this interval and on two wells back to back Pexus Hybrid technology has been implemented with impressive results. Multiple Pexus Hybrid runs with 80 - 120 hrs have been recorded with ROP improvements of 20 to 50% over conventional PDC designs. Dull grades on all of these Hybrid designs have been graded as good as 0 - 1 to 1 - 3 all in gauge with minimal to no signs of erosion.

Saskatchewan, Canada

An operator in the mid-western portion of the province drilled a multi-lateral horizontal play with 7 ⅞ in. PDC bits. The formation

consists of an array of transitional drilling challenges due to a mixed clast structure of shale and dolomite with scattered pyrite and calcite lenses throughout. Penetration rates of 30 - 90 ft/hr with bit runs of 1200 - 1500 ft was the expected performance based on prior runs with conventional PDC bits. Impact damage on conventional PDC cutting structures is the common dull characteristic due to the excessive vibration and abrupt changes in lithology. Predictive and consistent BHA tracking is also difficult to manage as reactive torque and changes in ROP tends to affect the direction of where the bits drill. The first Pexus Hybrid chosen for this application resulted in the length of the first leg being extended from 4200 - 5400 ft due to the drilling success. The BHA was then pulled back near the landing point and an open hole sidetrack operation was completed without making any changes to the bend setting of the motor or BHA. This successful sidetrack operation on the original bend setting after completing the first entire leg was a first for this application. After the sidetrack operation drilling continued until TD was reached on the second leg of over 2800 ft drilled. In summary, this was a single run drilling over 8200 ft with a penetration rate over 30% faster than

Figure 4. *Saskatchewan case study – Pexus dull condition.*

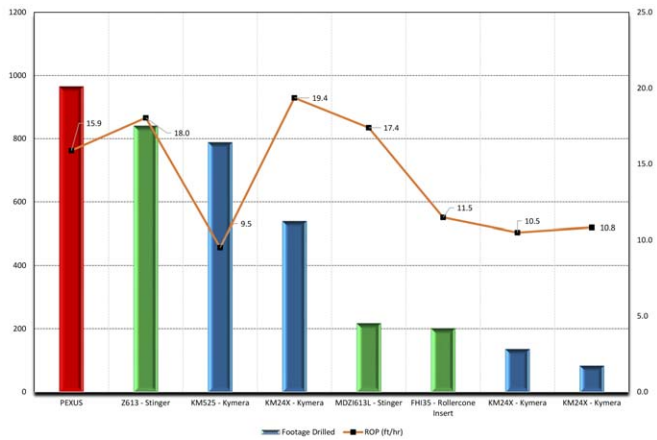

Figure 5. *Graph and data – North Western Alberta case study (imperial units).*

Figure 6. *Central Alberta case study – Pexus HDD application.*

conventional PDC expectations on the same BHA without changes to motor settings.

North Western Alberta, Canada

An operator drilling a challenging 8 ½ in. turn and build interval through very abrasive sand shale transitions consisting of chert lenses and siliceous cemented sandstone stringers was taking multiple bits to complete the interval. Conventional PDCs had to be pulled for toolface and directional control before the interval could be completed, coming out severely damaged by both abrasion and impact. Rollercone or rollercone PDC hybrid bits were required to land in the horizontal zone where ROP was sacrificed for directional control. The operator chose to compare the performance of a Pexus Hybrid design and the result was a single bit run to TD with increased ROP and no issue with directional performance on a conventional bent housing BHA. The dull condition was in gauge with very smooth sharp wear across the nose and shoulder of the cutting structure with no impact damage. The cost savings of not having to trip, at a measured depth of over 9000 ft, and the increased ROP over conventional PDC, rollercone, and rollercone hybrid bit performance was significant.

Central Alberta, Canada

An operator wanted to drill a challenging HDD pipeline river crossing operation with a 14 ¾ in. pilot bit. The operator was aware of the presence of gravel and possible boulders intermixed with sand and shale for the duration of the 5500 ft interval. The directional profile was to drill down at a high angle under the river and then gradually steer back up and break surface on the other side. Multiple bit trips are usually required due to the demand to maintain a sharp gauge to perform the demanding directional operation while handling the gravel and expected boulders. These operations typically take weeks with multiple bit trips, hole condition challenges and high on-bottom rotating hours. The bit chosen for such an operation was a six bladed, rotating Pexus Hybrid insert design. The result was a single run on conventional bent housing motor in under 7 days to TD, drilling at higher ROP than ever previously achieved.

Surpassing past barriers

All this hard work, commitment to investment, and new team synergy to continue developing Pexus Hybrid technology has proven to be worthwhile in the achievements and performance attained. Pexus Hybrid runs are exceeding 8300 ft drilled in a single run, achieving average penetration rates over 750 ft/hr, and cumulative run footages over 40 000 ft drilled. Multiple hybrid runs have involved drilling for over seven consecutive days without the BHA or the bit being tripped. Even though other advancements have been made, these types of bit runs can only be achieved when the drill bit is delivering minimal downhole vibration, leaving a good hole condition and generating minimal cyclic stress on the downhole motor and other BHA components.

Conclusion

The industry has never previously documented the kind performance improvements that have been achieved by drill bit technologies over the past two years. The future is bright for operators who are embracing these new technologies and taking advantage of working with the teams overcoming these challenges. The slowdown the industry experienced in 2014 and 2015 was harsh and many service companies, operators and individuals were not able to survive and reinvent themselves. With extreme pressure on economics, instinct and survival come to the fore. Those who adapt and persevere with quality, innovation and retained experience and expertise will benefit, and the oil and gas industry will continue to navigate forward in this changing world.

Turning the Tide with Biocides

Christina Pampena & Jon Raymond, Dow Microbial Control, consider the growth of glut-quat blends and their impact on hydraulic fracturing operations.

Hydraulic fracturing operators are well aware of the water-intensive nature of their work. It can prove to be a problematic relationship, with the threat of microbial contamination looming over the success of an entire operation. Uncontrolled microbial proliferation can negatively impact production rates, asset integrity and hydrocarbon quality, which means that completion engineers must select the most effective biocide programme for their well.

It all comes down to microbial control efficacy – a major consideration when selecting biocides. A wide range of biocides are available to the completions engineer, and each one performs differently depending on the phase in the process in which it is used. All three phases of water treatment in hydraulic fracturing – preparing the water, decontaminating the well and protecting the reservoir (Figure 1) – have different conditions requiring different performance considerations, including temperature, salinity, water turnover rate, and the desired duration of control. An integrated microbial control programme deploys a biocide, or combination of biocides, that addresses each phase of the process.

Oilfield microbial control continues to progress with new advancements and knowledge that have the potential to unlock new opportunities for enhancing productivity and reducing costs, especially in light of the limitations of commonly used oxidisers, such as chlorine dioxide (ClO_2) and surface active biocides such as tributyl tetradecyl phosphonium chloride (TTPC). The following is a look at microbial control trends driving the industry, and proven

chemistries that continue to offer value in shale plays across the US.

Glutaraldehyde and quaternary ammonium: a proven, robust solution

From topside to downhole, glutaraldehyde (glut) has proved to be one of the most versatile biocides available – efficacious throughout the preparation and decontamination phases with short-term effectiveness as a protective biocide. However, when combined with quaternary ammonium (quat), glut's performance sees a noticeable increase in kill speed. Glut-quat compounds are widely used for the control of microbes in water-intensive applications, such as hydraulic fracturing and waterflooding. These synergistic combinations are highly effective in controlling bacteria, and are ideally suited to meet the diverse demands of most oil and gas applications.

The efficacy of this combination was a driving force behind the development of AQUCAR™ 714 Water Treatment Microbiocide, an aqueous blend that combines the robust ability of glut and quat. It is especially effective in controlling both slime-forming and sulfate-reducing varieties of bacteria in oil and gas operations. Glut-quat blends are one of the most widely used biocides in hydraulic fracturing – not only because of the chemistry's ease of use in the field, but because of their ability to improve the performance of surface-active biocides. For example, foaming is reduced when compared to using quat alone.

Additional benefits include efficacy over a broad pH and temperature range, greater operational sustainability, compatibility with the most commonly used frac fluid additives, and cost-effectiveness, as well as a reduction in sessile microorganism populations known to cause corrosion and reduce heat exchange efficiency.

Glut-quat blend versus TTPC topside

Oilfield water contains an abundance of microorganisms due to its natural nutrient composition and the recycling process, so treating the water from the start with a quick-kill biocide helps enhance the performance of late-stage biocides by causing a quick reduction in the initial bioload.

TTPC has gained industry acceptance as an option for hydraulic fracturing. While its kill speed is well known, TTPC is hindered in efficacy due to its incompatibility with anionic additives, such as friction reducers, and proppants. TTPC also presents a foaming issue that can cause complications on the job site.

The combination of glut and quat provides a quicker kill during the frac fluid preparation phase than TTPC, and the effects of glut-quat mixtures last much longer (Figure 2). Whether in freshwater or a combination of fresh and produced water, glut-quat blends outperform TTPC at every turn.

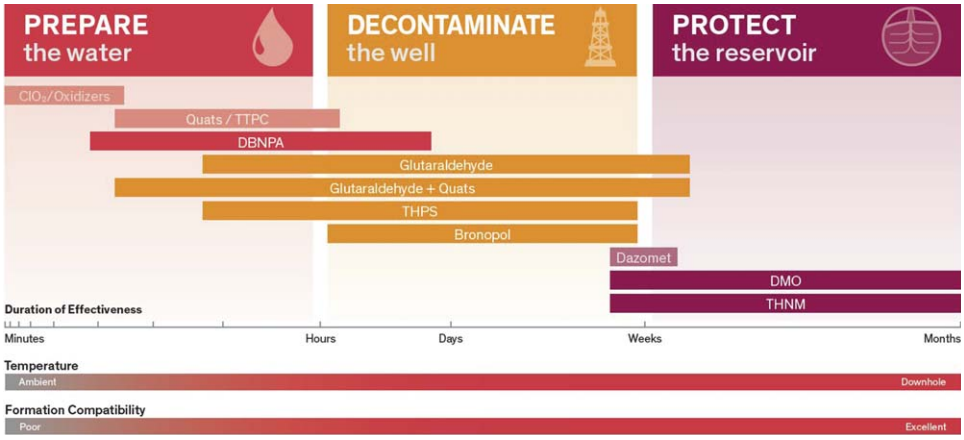

Figure 1. *Efficacy of biocides across three distinct phases of hydraulic fracturing operations.*

Active Ingredient	Biocide Compatibility/Efficacy Upon Blender Mixing			Rapid-Kill	Non-foaming	Non-corrosive at use levels
	Efficacious in presence of anionic additives	Efficacious in presence of proppants	Efficacious in high pH fluids (pH 9)			
Glutaraldehyde	+	+	+	+	+	+
Glut-quat blend	+	+	+	+	+/-	+
Quats (TTPC, ADBAC, DIDAC)	-	-	+	+	-	+
Preservatives (THNM, DMO)	+	+	+	-	+	+
Halogenated oxidizers	-	+	+/-	+	+	-

Figure 2. *Topside performance and biocide compatibility (from blender to wellhead).*

Active Ingredient	Biocide Compatibility/Efficacy Upon Downhole Injection				Capable of providing prolonged microbial kill under downhole conditions	Effective in mildly sour water (<100 ppm H_2S)	Non-corrosive at use levels
	Efficacious in high temperature systems	Efficacious in high salinity conditions	Efficacious in presence of shale	Efficacious in presence of proppants			
Glutaraldehyde	+/-	+	+	+	+/-	+	+
Glut-quat blend	+	+	+	+	+/-	+	+
Quats (TTPC, ADBAC, DIDAC)	+	-	-	-	-	+	+
Preservatives (THNM, DMO)	+	+	+	+	+	+	+
Halogenated oxidizers	Not suitable						

Figure 3. *Biocide compatibility downhole (from wellbore to formation).*

Glut-quat blend versus TTPC downhole

Downhole environments provide hot, saline-rich conditions that can lead to extremophilic microorganism proliferation. Biocide treatment used during the well decontamination phase aims to provide microbial control for a week or more during drill out up to initial production. Once again, glut-quat blends offer a more effective option in this scenario compared to TTPC.

TTPC's incompatibility with proppants remains an acute problem, but there are several other issues with respect to its usefulness in downhole environments. TTPC is a surface-active biocide and will almost immediately adsorb onto shale, thereby losing its efficacy in the process. By contrast, the inclusion of glut gives the glut-quat mixture a reactive quality, which supports efficacy against planktonic bacteria, even in the presence of shale (Figure 3).

Glut-quat blends provide sustained microbial control for as many as seven days at temperatures of up to 158˚F (70˚C) when dosed according to label instructions. TTPC cannot match that timeframe, and the impressive balance of glut-quat's kill speed and staying power is a clear performance benefit.

Rising trends and dropping temperatures

From well-established basins like the Permian to colder regions like Western Canada and the Bakken, hydraulic fracturing activity continues to rise across North America. Shale basins are dependent, in part, on their surrounding environment, so as demand for oil increases in the Canadian, Bakken and Marcellus Basins, so has the need for winterised biocide products.

The latest trend in meeting cold weather microbial control comes in the form of another glut-quat blend – specifically, the combination of glut and N-alkyl-dimethyl-benzyl-ammonium chloride (ADBAC). This blend is highly effective in controlling problematic microorganisms across a variety of conditions, and is engineered to meet the demands of harsh, cold temperature environments. The glut-ADBAC blend resists freezing at temperatures as low as -40˚C. This advanced technology is awaiting final US Environmental Protection Agency (EPA) and Canadian Pest Management Regulatory Agency (PMRA) approvals, which are expected later this year.

Similarly, AQUCAR™ TN 250 LT Water Treatment Microbiocide is an antimicrobial agent designed to control bacteria under reservoir conditions for months, and is winterised to minimise freezing at temperatures that reach as low as -40˚C.

Downward doses and efficacy

TTPC and other chemistries have gained popularity in recent years due to their lower cost per unit. At the same time, biocide doses have decreased onsite. This 'less-is-more' trend suggests that many operators do not fully recognise the value of an integrated biocides programme that goes beyond topside quick-kill treatments.

Take ClO_2 as an example. The compound is highly reactive, which means that it is quickly consumed through chemical interactions with other frac fluid additives, leaving less to kill bacteria in the wake of its initial use. And, if ClO_2 residuals remain, they quickly lose efficacy downhole because the biocide is prone to degrading at high temperatures.

Short-sighted decisions to cut costs without understanding the impact on operational efficiency can cost operators more in the long-run. It is important to distinguish between cost per unit and cost to treat when evaluating the cost of a microbial control programme. Despite the perceived low cost of ClO_2, glut-quat blends can provide a 10 - 50% lower cost to treat.

Longer-term state of mind

Another more promising trend in microbial control is the growing interest in solutions that offer long-term protection in the downhole environment. This includes a mental shift from focusing on the lowest unit cost to the total cost to treat. Whether it be more stages per frac, lower quality proppant or the recycling of produced water, changes in well construction today require solutions that offer downhole protection for extended periods of time. Solutions that last for weeks or months – as opposed to just seconds or minutes – are now a necessity.

The oil and gas industry is both changing and growing at an unprecedented rate. As a result, biocide efficacy is critical to make hydraulic fracturing operations efficient and profitable. Confidence in one's microbial control programme is necessary to thrive in today's competitive landscape, and only by taking the time to understand and implement an integrated approach can that confidence be achieved. An effective biocide programme – one that accounts for duration, temperature and higher efficacy – is a relatively small upfront investment that can enhance production and hydrocarbon quality over the entire lifecycle of a well.

Andrew Sherman and Anupam Ghildyal, Terves, USA, discuss the expanding use of dissolvable tools in the oil and gas industry.

DRIVING FORWARD WITH DISSOLVABLES

Less than five years ago, dissolvable tools were considered to be a niche concept while today almost every oil and gas company has used dissolvable tools. From 'dissolvable tools might have a couple of applications' to 'the possibilities are just endless with dissolvable tools' – the adoption of this technology has been rapid. Dissolvable or interventionless tooling has clearly established its value proposition of lowering operating costs, boosting efficiency and increasing revenue by enabling longer laterals. Five years ago, dissolvable tools were 8 - 10 times the cost of composite tools with only a few suppliers; today they are less than 4 times the cost of composite tools and most service companies offer at least some dissolvable tools. It is expected that by 2020 the cost of dissolvable tools will be low enough that not using them would be considered irresponsible. Much of this increase is due to the development of higher strength and stiffness, brine and freshwater dissolvable metals, versus earlier polymeric materials. Terves®, with its family of TervAlloy™ dissolvable metal solids and tubulars and ElementUM™ dissolvable elastomers that are used to make frac balls, plugs and other completion and production tools, aims to increase reliability and lower the cost of dissolvable tools.

In today's extended lateral drilling environment, dissolvable plugs, dissolvable balls, inflow-control devices, pre-perf liners with dissolvable plugs, dissolvable barriers, and other interventionless tools developed using dissolvable and reactive technologies can go beyond coiled tubing reach to increase production; potentially removing the need for intermediate casing and liner, reducing water usage, and simplifying operations. Multiple studies have shown that dissolvable frac plugs, dissolvable balls, and other dissolvable tools can save hundreds of thousands of dollars for each well by eliminating the need for coiled tubing drill-outs, snubber rigs, and workover rigs. Pre-perf liners and screens with dissolvable elements or plugs can allow for pressure integrity testing while eliminating the need for a middle completion string, dramatically reducing well completion costs in offshore applications.

A wide range of dissolvable materials

Terves uses conventional casting and extrusion processing using alloys and melt processing to transform conventional high strength magnesium alloys into controlled degradation alloys. The high strength, heat treatable casting alloys enable lower cost and high production capacity to meet the growing market needs. The company also has a wide variety of dissolvable alloys that include: brine, fresh water and acid dissolvable; low, high, and very high dissolution rates; standard, low, and high temperature alloys; standard and high ductility alloys; and low-cost near net-shape castings.

Additionally, Response™ coatings provide for time-delayed, acidising, temperature or chemical pill triggered dissolution. High hardness, erosion-resistant dissolvable metal matrix composites (hardness of up to HRC 35), and ElementUM dissolvable elastomers have also been developed. TervAlloy metals are available in both tubular and solid forms, and can be permanent-moulded, investment- or die-casted into near net shape parts. DissolvAssure™ and DissolvAssist™ technologies enable positive identification of removal and accelerated- or assisted-dissolution for when operators have concerns over removal time or completeness.

Enabling the first fully-dissolvable frac plug

Dissolvable frac plugs for plug-n-perf completions and zonal isolation are the primary application for dissolvable metals in the industry today, taking over from dissolvable frac balls used in sliding sleeve completions for volume applications. To enable the first fully-dissolvable frac plug, a dissolvable elastomer has been developed in addition to its dissolvable metals – but there was something still missing: a high hardness dissolvable metal that can replace ductile iron components (buttons, seats, seals, etc.) in the frac plug. TervAlloy MMC, a dissolvable metal matrix composite in the final stages of development, has been designed as a high-stiffness, erosion-resistant dissolvable material that offers up to 35 Rockwell C hardness, and high stiffness for valve seats, scrapers, grips/clamping elements, and ultra-high-pressure rating frac balls and seats. The composite is a replacement for cast iron components and steel and ceramic inserts, and unlike these materials the components made from this metal matrix dissolve and go away when the job is done.

Expanding the use for dissolvables

To expand the use of dissolvable materials and respond to operator reliability concerns, Terves has recently launched fresh-water,

higher-strength, high-ductility and low- and higher-temperature TervAlloy dissolvable alloys. The company also offers supporting technology, including dissolvable elastomers; chemical- and temperature-trigger, and acidising and time-delay coatings; erosion and wear resistant dissolvable metal matrix composites and coatings; and expandable (permanent and dissolvable) materials that support advanced tool designs and new and novel uses of reactive structural materials. Additionally, DissolvAssure and DissolvAssist technology, incorporates tracers, tags, and controlled release chemicals such as solid acids and PH buffers to the dissolvable alloys and components to assure complete dissolution (degradation) and tailor removal times for operator needs.

A range of metallic and polymeric coatings and claddings have been developed that protect dissolvable tools from acids and also ensure that dissolution begins only when desired. Furthermore, custom coatings have been developed which are removed when exposed to specific acids or high temperatures, and then the dissolution begins. Lower-dissolution rate alloys can be clad onto high dissolution rate cores, or accelerants can be added to the core alloy to produce tools that do the job and then degrade quickly to allow the well to be put in production faster than conventional tools. These tools allow specific removal profiles to be engineered to accommodate a given operator or region's desired completion profiles or conditions.

Efficiency drives adoption

Hydraulic fracturing has transformed the oil and gas industry, however, extraction of only 10% of oil and 25% of the gas from fracked wells leaves a lot of room for improvement. Almost 70% of historical unconventional wells did not reach their production target and 30% did not produce as much oil and gas as expected. As oil and gas prices began to drop, service companies have been aggressively deploying new technologies to save money – one of these technologies is dissolvable metal tools that not only enable longer laterals but also allow oil to flow more freely. One operator stated that the adoption of dissolvable frac ball and plug technology was essential in dropping completion costs to remain competitive during the downturn. With more service and tool companies bringing new tool designs and completion methods, supported by the availability and cost-effectiveness of dissolvable and engineered response materials from independent developers and suppliers, the industry can expect a rapid proliferation and improvement in interventionless completion services over the next few years.

The future of dissolvables

When asking any operator or service company about the value proposition of dissolvable tools, the unanimous answer is dissolvable tools will enable longer laterals and drive operational efficiency. So, why are dissolvable tools not being used in every well? The answer is a combination of concerns about reliability and higher costs, along with a rapid drop in drillable composite and rig costs. As rig utilisation increases driving a price recovery, new material/design innovations and economies of scale drive dissolvable tool costs down, and more operator and service industry experience (and technology innovation) improves reliability; the use of interventionless tools is expected to undergo rapid growth over the next five years, from 2 - 5% of the tool market today, to as much as 50%. New materials and designs, as well as deeper interaction between designers and operators will enable faster and more reliable tool operation (setting, ratings, and removal times), while costs will continue to decrease.

Why dissolvables?

- Enable longer laterals without the cost or risk to run-in coiled tubing or middle string for drill-out or other intervention, eliminating concerns such as low weight on bit or spinning ball or component for long coiled tubing drillouts.
- Provide lowest life-cycle cost which includes lower costs (plugs, mill outs, circulation/clean-out, water cost and disposal), lower (intervention) risks, and higher production.
- Eliminate costs, risks and uncertainty associated with plug milling and retrieval, such as availability/cost of coiled tubing, formation damage caused during milling, coiled tubing getting stuck or damaged during milling, and cost and potential inability to circulate cuttings out of the wellbore.
- Reduce or eliminates skillsets required for intervention/clean-out and can remove need or manage delay and logistic risk for intervention for snubber and other coiled tubing intervention, particularly in emerging areas or as equipment utilisation rates increase.
- When used in triggered pre-perf or limited entry liners, delay inflow-control sleeves, etc., for open hole or conventional completions, it can remove the need for a middle completion string, reducing completion costs dramatically, particularly offshore.
- Enable new completion methodologies to be deployed.

Conclusion

Frac balls and frac plugs were the lowest hanging fruit and are the leading applications for dissolvable metals; which have provided the required validation to transition from 'high potential' to 'high value.' Today, operators continue to work with leading service and tooling companies across the globe to innovate and transition dissovlables and other engineered-response material enabled devices from 'niche applications' to the 'default choice'.

Figure 1. *Terves' ElementUM is a family of high-performance, mouldable and machinable true elastomers that are designed to fragment and dissolve to tiny particles after exposure to downhole brine solution at temperatures above 130˚F.*

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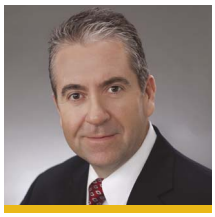

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Q&A COMPLETIONS

OILFIELD TECHNOLOGY INVITED EXPERTS FROM CARBO, FRANK'S INTERNATIONAL, CATERPILLAR, AND TENDEKA TO SHARE THEIR KNOWLEDGE ON A VARIETY OF COMPLETIONS TOPICS. READ ON FOR INSIGHTS FROM:

CARBO

TERRY PALISCH is global engineering director at CARBO Ceramics and leads a team advising clients on completion/fracture optimisation. He has authored over 40 SPE technical papers, is past chairman and board member of the SPE Dallas Section and is a member of the ATCE Program committee, including the 2017 Program Chair.

FRANK'S INTERNATIONAL

STEPHEN LEBLANC currently serves as Engineering Manager in the Technology Enhancement department. He has held various roles since joining Frank's International in 2008, including Design Engineer and Engineering Team Leader.

DR. BRENNAN DOMEC is the Director of Strategic Technology at Frank's International. Dr. Domec leads a team of multi-discipline engineers, scientists, and researchers tasked with the research and development of emerging and disruptive technologies, rig-of-the-future concepts, and think-tank ideation.

LOGAN SMITH has been with Frank's International for 12 years and is currently New Product Delivery Manager and oversees efficiently launching new products and services.

CATERPILLAR

DANIELLE WILLS is a Marketing Representative for Caterpillar Oil and Gas. She holds an BBA in Marketing and Management from the University of Houston.

SHAUN BOLLER is the Pressure Pumping Specialist for Caterpillar Oil & Gas, supporting both Well Stimulation Pumps and the PEMS® Pump Electronic Monitoring System.

MARTIN BAEHR is the marketing and training manager for Cat Connect within Caterpillar's Oil & Gas business unit. He graduated in 2007 with a Bachelors in Business Administration from Robert Morris College.

CASEY OTTEN is a Product Application Specialist for Caterpillar Petroleum Transmission and has 15 years of experience with Caterpillar transmission design and application.

DEREK KAMP is the Well Service Industry Manager for Caterpillar Oil & Gas. He is a graduate of Bradley University with a Degree in Mechanical Engineering. He has been with Caterpillar for 15 years and has held multiple commercial roles in Cat Oil & Gas.

TENDEKA

ANNABEL GREEN joined Tendeka from Weatherford where she spent more than 14 years in numerous technical and R&D roles – both in the UK and overseas. She has broad experience in sand control, reservoir completions and general completion technology across global markets.

COMPLETION TOOLS

TENDEKA – ANNABEL GREEN

In conventional reservoirs there are two main reasons for running a completion across the reservoir: to control sand production and/or to optimise inflow.

Both are highly specialised subjects, and this is reflected in both the range of technologies and the ongoing focus on development in these areas. Inflow optimisation is fundamental to field economics; in the FEED phase, long before a final investment decision (FID) is made, evaluation and screening of potential reservoir or advanced completions executed.

Detailed planning of the optimal completion configuration occurs throughout the execution phase with final configurations often determined only once the logging while drilling (LWD) data becomes available and the completion is lying on the deck of the rig. This reservoir completion is then expected to provide the functionality required for the life of the well. Top-hole workovers are common practice but for reservoir completions this is where operations end, or at least it used to be.

As fields mature, the range of production and recovery challenges increase or become more apparent – unwanted fluids are produced, differential depletion occurs, and hydrocarbons are bypassed. On the flip side, new developments provide an increased range of solutions that can contribute to improved performance, and so a trend towards retrofitting advanced completions into existing wellbores can be seen. These are not only aimed at improving production but optimising secondary and tertiary recovery projects and reducing well intervention requirements.

There are some key technologies that are enabling this trend:

- Through-tubing autonomous and wireless technology that can be installed to manage inflow without linkage back to surface or mechanical manipulation.
- Advanced packer technologies that can compartmentalise the production zones.
- Chemical solutions that can access the existing wellbore annulus and high expansion swellable and mechanical options.

As with primary reservoir completions the range of technologies is increasing with the latest systems offering full intelligent completion functionality.

CATERPILLAR – SHAUN BOLLER & DANIELLE WILLS

Fluid end and power end maintenance are significant cost drivers for pressure pumping operators. Even with proper employee training and diligent pump maintenance, seemingly minor problems can cause catastrophic failure of components, leading to extended downtime or removal of the trailer from the well site.

Based on extensive research with customers, the PEMS® Pump Electronic Monitoring System was developed for new installation on or retrofit of triplex and quintuplex well stimulation pumps in the 2000 - 3000 hp range. The PEMS instrumentation covers both the fluid end and power end and can mitigate severe damage to all pump components as its J1939 diagnostic event codes are displayed to the operators. The J1939 output is agnostic to the trailer control system and is designed for simple installation and minimal commissioning.

The heart of the system performance is a diagnostics decision engine which analyses the pump components with sampling rates corresponding to the speed of each potential failure phenomena – be it fluid end leak or cavitation, or issues with the power end lube circuit. The system also maintains summaries of pump utilisation to help correlate maintenance schedules with duty in service.

FRANK'S INTERNATIONAL – STEPHEN LEBLANC

Mechanical damage to the surface of corrosion resistant alloy (CRA) tubulars, which the dies of conventional power tongs often impart during the installation process, has the potential to lead to premature failure of the tubular in the wellbore. Considering the high cost of CRA tubular goods, in addition to the cost, time, and danger associated with pipe failure, it is critical to minimise all surface damage during assembly and disassembly of threaded connections.

An improved means for gripping tubular goods, one that does not cause surface damage or structural deformation, is the Fluid Grip® Tong, wherein an inflatable bladder-like structure pressurises the tubular so that friction can transfer the torque to make the connection. In contrast to conventional gripping devices with CAM-activated jaws and dies, the Fluid Grip Tong requires the introduction of hydraulic fluid flow and pressure to pressurise elastomeric bladders, which effectively establish a high friction engagement between a rigid outer housing that encases the elastomeric bladders and a tubular member. The generated hydrostatic pressure is evenly distributed about the circumference of the tubular member, resulting in a significant reduction in contact stress and the reduction or elimination of connection distortion and zero permanent defects on the surface of the tubular.

The latest iteration of the Fluid Grip technology, the Remote Fluid Grip Tong, has been used successfully on several jobs, including a deepwater project for an independent operator in the Gulf of Mexico. Frank's International landed out the first completion for this project using the Frank's remotely-controlled Fluid Grip Tong (patent pending). The Remote Fluid Grip Tong was deployed first to build stands on the auxiliary side rotary. After which, the Remote Fluid Grip Tong was used to run 19 502 ft of 5.5 in. 23 and 26 lb/ft tubing and 4000 ft of 7 in. vacuum insulated tubing (VIT), for a total buoyed weight of 659 304 lb. The minimal tubular surface damage and the increased safety of a remotely-controlled system made this an effective choice for the customer.

Using new non-marking technologies such as the Remote Fluid Grip Tong will result in less pipe body failures due to accelerated corrosion with the added safety benefits of operating the system using remote control panels away from the rig's rotary.

MULTISTAGE COMPLETIONS

CARBO – TERRY PALISCH

In multi-stage hydraulic fracturing programmes, there are many variables that can alter the effectiveness of the frac design. These factors include well volume, proppant selection, fracture spacing and treatment rate. Effective frac designs can enhance production and improve

operating economics by preventing design, operational and production issues that typically arise during the fracturing process. STRATAGEN, a CARBO business, provides fracture consulting services, specifically fracture design and evaluation, onsite fracture supervision and advisory services and well performance analysis to identify the optimal balance of contact and conductivity for the reservoir and to safeguard fracture execution.

STRATAGEN has developed BASINWORX™ to provide operators with a multi-well evaluation for frac and completion optimisation. BASINWORX employs artificial neural network (ANN) modelling and other artificial intelligence techniques as well as machine learning techniques to develop data-driven models to identify factors that optimise production in fractured completions. The key indicators of reservoir performance are used for the optimisation of frac and completion designs.

Models are built from completion and geology data types to predict new well production. The BASINWORX modelling process includes the following steps:

- Build a predictive model by incorporating multidisciplinary data and artificial intelligence modelling technique.
- Perform sensitivities on the model to quantify the impact of each predictor and rank significance.
- Evaluate well performance using alternative completion and frac designs.
- Discover hidden correlations within the data using advanced multivariate statistical data evaluation.

BASINWORX evaluations provide an index of the critical reservoir, drilling, fracturing and completion factors that drive productivity in the field. When working with unconventional reservoirs, success is largely contingent upon identifying the optimal frac and completion design for each particular well. The detailed multi-well evaluation produced by STRATAGEN's BASINWORX can assist in developing more effective frac designs both economically and for enhanced production.

WIRELESS SYSTEMS

CATERPILLAR – MARTIN BAEHR & DANIELLE WILLS

Cat® Connect is changing the way equipment is monitored through a collection of services, which provide a remote monitoring system to help remove guesswork from asset management. The system allows operators to work efficiently and smarter by receiving accurate, timely and useful information about location, utilisation, and the condition of equipment. This type of information can make a huge difference in the efficiency and costs of the entire operation.

One service within the system is the Product Link™ Web, which has an intuitive web interface that transforms data from a customer's entire fleet of equipment into the essential information required to boost productivity, reduce costs, and manage risks. With Product Link hardware and Product Link Web services, customers know where their equipment is, what it is doing, and how it is performing.

One of Caterpillar's newest features for this hardware is the Product Link Configuration Tool. The company has developed an online and offline version of the tool to allow users access to more features. The tool provides a common user experience between the online and offline tools. Both the online Product Link Web Configuration Tool and offline Product Link Local PC Configuration Tool have similar features such as, creating and editing a configuration, using templates to add parameters and features, and deploying the configuration to the PLE601 Network Manager. In addition, the local PC offline tool has extra features to help make importing, editing, and redeploying files an easier process for the user.

TENDEKA – ANNABEL GREEN

To combat the limitations associated with the use of conventional control lines, the development and deployment of wireless completions equipment is now becoming more prevalent.

From drill stem testing to multi-node intelligent completions, the shift from downhole equipment with no communication and/or actuation mechanisms to wireless technology represents potentially huge efficiency and performance savings, as well as improved safety. However, these solutions tend to be targeted towards new field developments where there are currently limited options for replacement of failed equipment, or applications for existing wells, other than to conduct a complete workover.

For instance, there are a variety of digital oilfield solutions on the market today for topside applications, which can be integrated into existing fields to manage data and automate processes. Unfortunately, the same cannot be said for downhole solutions. The limited scope of intelligent equipment available does not address the needs of existing assets and can therefore demonstrate limited value. Without these retrofittable, intelligent downhole systems, the full benefit of the digital oilfield is beyond the reach economically for many mature fields.

Tendeka has developed a pressure pulse telemetry system, which can be applied to downhole devices for communication in a flowing well. The system provides a versatile wireless alternative to existing data transfer and actuation methods within both production and injection wells.

The telemetry was first applied to a retrofit downhole pressure and temperature monitoring system, creating the PulseEight Wireless Gauge, which expanded upon the limited functionality of the traditional industry memory gauge. This provided a means of adding real time downhole data from an existing well into reservoir models, rather than waiting for the memory gauge to be retrieved to surface for download before analysis could begin.

The system's additional ability to function autonomously in reaction to specific wellbore events, without the need of surface instruction, opens a new chapter in the digital oilfield delivery. It now brings aspects of data analysis downhole to illicit responses in a timeframe unachievable by traditional human analysis and action alone.

Intelligent, wireless technology, as a minimum, could simplify and confidently advance digital oilfield operations by removing the need for traditional hydraulic or electric control lines. The removal of these items can positively impact overall system costs whilst delivering an improved design from a safety aspect. Moreover, the truly intelligent capability of modern tooling sees the absolute need of surface data analysis for key trigger points in the well lifecycle to be mitigated, leaving engineering time to focus on more complex aspects of the reservoir's production potential.

The future for this and other technologies should be to extend the operating envelope for intelligent completions

and address its various applications. With advances in surface data analysis, autonomous completion tools which can link both inter-tool, but also inter-well, should be considered as the next step for production optimisation over multiple wells and have demonstrable value to both existing and new field developments.

SAND CONTROL

CARBO – TERRY PALISCH

During 'Cased Hole Frac & Pack' (CHFP) stimulation, proppant fills the wings of the fracture, then the annulus between the casing and the screen with the annular pack providing a secondary barrier for sand control. Over time, conventional proppant washes out of the annulus, creating voids and allowing the ingress of formation fines. Eventually, the connection to the fracture can be lost and the pressure needed to inject at the required rates becomes so high as to make injection economically unviable. CARBO developed a new type of immobile proppant system that would bond the highly conductive proppant pack in the formation and the annulus without closure stress so that operators can inject at ultra-high rates for many years and at pressures exceeding the parting pressure of the soft sand formations.

A resin coating is applied to a lightweight ceramic substrate, a chemical activator that could be run in the proppant slurry and an internal tracer placed inside the proppant during manufacturing. The solution became known as FUSION technology due to the combination of these four technologies.

The specially formulated chemical activator was developed to enable the resin coating to bond in non-compressive and low-temperature environments (in the annulus as well as in the fracture), creating a high integrity pack that withstands stress cycling while sustaining long-term pack integrity. As the FUSION coating also bonds with closure stress, it works to maintain the integrity of the proppant pack in the fracture. The bonded proppant in the fracture minimises embedment in the formation face, prevents prop pack rearrangement and lowers the delta P across the pack. It also allows for a single resin-coated proppant and liquid additive to be used simultaneously in a continuous frac and pack operation. As the unique bonding process is chemically and temperature activated, any excess proppant in the workstring can be reversed out prior to the bonding of the proppant pack.

An inert, non-radioactive tracer, CARBONRT, is added to the ceramic proppant mix and incorporated into the ore used to make each pellet. It is detected downhole by wireline tools and interpreted at surface, helping operators to identify where voids are present in the pack. For the entire life of the well, operators can re-log the well and determine annular pack integrity, near wellbore connectivity and propped fracture pack height.

SAFETY SYSTEMS

FRANKS INTERNATIONAL – DR. BRENNAN DOMEC

There are many instances in the oil and gas industry where serious bodily injury or death has been caused by a person being struck by or being caught between equipment. Often, the cause of these incidents is human error, either on the part of the tool operator or the person who finds themselves in an unsafe position. Current anti-collision or zone management systems do not track personnel, cannot stop a machine from colliding with a person, are rig specific, and are difficult to integrate with third party equipment.

Current technology on the market can help prevent these incidents using a control system capable of knowing the location of personnel and tools in the area. GPS systems do not function when line of sight or the satellites are lost and only has an accuracy of 3 m. Other technology such as radio frequency identification (RFID) can only reliably tell when a person or object possessing a tag has passed through a gate. There are also real time location systems (RTLS) that use existing WiFi networks and Bluetooth beacons to track a person's position and movement, but the accuracy varies between 1 - 3 m. New technology using ultra-wide band (UWB) has brought the ability to track position to an accuracy up to 10 cm in a work environment.

Frank's International is using UWB technology to provide a proprietary portable local positioning system (PLPS) that monitors and tracks the real time position of personnel and machines on a rig floor and prevents the machines from operating when a human could potentially be injured. The Frank's Vigilance™ system is designed to be portable and easily and quickly installed and configured onto any rig floor and work with any equipment. By having knowledge of the real time location of all personnel and all mobile and stationary equipment on the rig floor, this system automatically locks tools in place and prevents them from moving whenever a person is in an unsafe position relative to the tools on the rig floor. The system could help provide insights into lessons learned, incident investigations, operations efficiency, and process automation. This new technology could also provide insights into operations optimisation and enable the development of smarter systems that are currently not feasible.

In the short term, this new technology provides an engineered control solution for hazards associated with people working around automatically-controlled or remotely-operated machines on a drilling rig floor environment. It also allows for easier rig integration or even the ability to provide a stand-alone alternative to the rig's anti-collision systems. In the long term, the Vigilance™ system is an enabling technology that would provide a foundation network for enhancements in many areas including process control, intelligent system automation, machine learning through patterns of movement, and efficiency gains through path anticipation/optimisation.

FRANKS INTERNATIONAL – LOGAN SMITH, P.E.

Offshore drilling wells have been reaching increasingly greater depths, some over 30 000 ft. At such depths, the sediment level, which can extend hundreds of feet below the seafloor, is typically composed of a loose matrix of materials, thereby imparting negligible cohesive strength. In fact, rather than a rotary drill bit or drilling mud, the combined weight of the conductor casing and drill string may be sufficient to create the first hole. Nonetheless, a jetting procedure is incorporated into the operation to ensure proper placement of the conductor casing. As the foundation for the rest of the well, should this initial string collapse due to the critical structural loads experienced at these depths, every deepwater component

above and below the conductor casing would be jeopardised. As a precaution, operators have trended from 30 in. to 36 in. structural casing and higher grades of steel. The problem is that the traditional method of jetting large-diameter pipe can prove problematic because it requires padeyes or other lifting profiles, which can impair safety.

The removal of padeyes can be troublesome. Casing's high-grade materials are not designed to withstand heating outside of a controlled environment, so the torches and grinders used to remove these padeyes can damage and/or weaken the structural capacity of this string. Like padeyes, other lifting profiles have drawbacks, too. The installation and removal of lift subs and clamps prove cumbersome and time-consuming. Furthermore, the height at which these implements must be manipulated necessitates personnel working at these heights.

However, recent tools such as the Frank's Jet String™ Elevator (JSE) reduce these safety hazards. The JSE is designed to lift flush OD 30 in. to 42 in. casing from the horizontal to vertical position, helping eliminate the need for welded or bolted-on padeyes and thereby improving the overall safety of operations. In addition, its completely hydraulic design allows tool operation to be hands-free, eliminating the need for dangerous manual manipulation and removing the rig crew from the Red Zone.

Overall, the JSE and other modern tools are a marked improvement over traditional tools and improve safety on jobs that were previously run with crews handling heavy equipment and using cutting and welding machines on the rig floor.

CATERPILLAR – CASEY OTTEN & DEREK KAMP

Caterpillar is committed to making well service jobs safer and more efficient. It was with safety in mind that the Dynamic Transmission Output Control (DTOC) technology was developed for the company's well service transmission product line. DTOC is an integrated set of control features designed with knowledge of the pump engine and transmission operating characteristics. The automated stall test mode (ASTM) improves site safety by automating the manual processes currently used to pressure-test jobsite iron. Automated speed control (ASC) and economy mode allow automated rate control for a single pump rig, or the entire fleet, and can help reduce fuel burn at the same time.

In addition, DTOC can easily be integrated into nearly any third-party control system, it is intuitive and easy to manage for any experienced well service operator.

ASTM simplifies the pressure-test process for the operator by allowing them to simply enter the desired pressure into their control screen, and activating the feature. Once ASTM is activated, the transmission controller takes over and controls transmission gear and engine speed to achieve the desired pressure. Previously, an operator had to manually control the transmission gear and engine speed. With the ASTM feature, operators can now perform jobs more safely and efficiently.

Low-flow applications like cementing present unique challenges. ASC was created to meet today's work demands of high levels of speed, reliability, and the ability of the engine and transmission to achieve precise flow control even at the lowest rates.

This feature was designed to automate pump rate control. With ASC, operators can input the rates they want allowing for a more streamlined process compared to the manual process used in the past. One of the primary benefits of the technology is the ability to achieve consistent low flow during critical cementing applications.

On today's well service pumping equipment, pump flows are controlled by controlling engine speed and selecting the gear that provides the flow-rate nearest to the target flow rate. Each transmission gear shift increases pump flow and potentially pressure. With ASC, the rate control feature simplifies the pump control by allowing the operator to simply type in the desired flow rate. The technology then takes control and commands engine speed while selecting the appropriate gear to achieve and maintain the desired flow. While in ASC mode, the transmission will automatically shift gears as necessary and will control the gear shift and engine speed to maintain the desired flow rate before and after the shift, thus ensuring there are no flow spikes during the gear shifts. With economy mode activated, the transmission will achieve and maintain desired flow while operating at the most fuel efficient operating point, helping minimise fuel burn.

The simplified operation of DTOC and both the ASTM and ASC features provide for a safer and more efficient well service job.

CHEMICAL TECHNOLOGY

TENDEKA – ANNABEL GREEN

To maximise return on investment, reducing the time and cost to complete wells in unconventional shale plays is crucial, particularly given the increasing trend to pump more proppant per 1000 ft as well as the associated increase in volumes of fracturing fluids.

One such way to achieve this decrease in time and cost is during perforating in the acid stage during plug and perf completions. This new process and technology eliminates the procedure of placing acid 'after' the guns are removed from the well. A spearhead acid stage is typically pumped prior to the main fracturing stage to clean cement debris and generally assist in reducing initial injection/fracture pressures. Taking a four well pad as an example, with 50 stages per well, with an average displacement volume of 250 bbls and acid displacement time of 20 to 60 minutes per stage (based on pump-down method and rate), this would amount to over 50 000 bbls of fluid and up to 200 hrs of equipment time that could potentially be minimised.

The application of perforating in acid is not a new concept, but to date, its use has been limited in unconventional shale plays because of the corrosive properties of the hydrochloric acid (HCl) or urea-hydrochloride and the temperature limitations of urea-based products.

A new thermally stable Modified Acid™ system is now available and is already in use by various North American operators. It shows improved performance properties compared to hydrochloric or urea-based acids, without the hazardous/negative exposure, transport, effluent, and corrosive properties associated with HCl. This system is a replacement for hydrochloric acid blends and can be utilised and exposed to perforating tools and wireline at high temperatures over long periods with minimal effect. This system allows operators to pump acid with the perforating guns and plug, reducing time per stage and saving considerable water per stage (a hole-volume per stage) where applicable.

In addition to the advantages of this system, it also achieves ultra-long-term corrosion protection on corrosion resistant casing

widely utilised in industry, such as P110. Casing integrity issues have been observed by multiple operators due to spearhead acid placement (hydrogen embrittlement). This system will provide corrosion protection well below the industry standard of 0.05 lb/ft^2 for up to 96 hrs versus the usual 6 hrs provided by HCl based systems, virtually eliminating the risks of casing integrity.

CARBO – TERRY PALISCH

Operators of wells situated in some remote onshore or offshore locations are days or months away from being able to remediate their wells' operational issues once they become apparent. Scale deposition downhole is, in particular, a common oilfield production problem with the potential to cause major blockages in tubulars and proppant packs. This can dramatically limit the efficiency and effectiveness of downhole pumping equipment. Oil flow can become restricted with production needing to be halted. Scale remediation can spell costly workovers and pump repairs, which lead to further production downtime and lost revenues. With the cost of scale inhibitor delivery solutions, such as chemical injection systems and remedial chemical squeezes proving to be prohibitive in most cases, the CARBO SCALEGUARD proppant-delivered scale-inhibiting technology was developed as a one-time scale inhibitor that is designed to be used with the completion, blocking scale at its point of origin, and can be engineered to last for the effective life of the well, giving operators an added degree of confidence in their wells' integrity.

SCALEGUARD is comprised of a porous, ceramic proppant engineered with a controlled release technology and infused with scale-inhibiting chemicals. The water-activated technology is designed to be placed throughout the entire fracture as part of the standard fracturing process, with a single treatment capable of safeguarding the entire production system, from the fracture through the wellbore, to the surface processing equipment for the life of the well. Serving as both a scale inhibitor and proppant, the technology has no impact on fracture conductivity or integrity, nor does it create excessive fines that restrict or block hydrocarbon flow spaces. Controlled release technology lengthens treatment life and reduces initial inhibitor washout, ensuring that scale-generating water is constrained at a controlled rate so that levels remain above the minimum inhibitor concentration (MIC) determined for each application. By placing the production assurance chemicals directly in the fracture where they are required and avoiding chemical washout, the technology provides effective, long-term protection while reducing chemical consumption and treatment costs. It has been deployed across the US, in every major basin including the Gulf of Mexico and Alaska, as well as Canada.

HPHT APPLICATIONS

FRANKS INTERNATIONAL – DR. BRENNAN DOMEC

As oil and gas wells are being drilled in more aggressive environments, the use of corrosion resistant alloy (CRA) tubulars for well completions is increasing. One such alloy that has seen and will continue to see considerable use globally is 13Cr. This alloy is hardened by quenching and tempering, which often results in a hard oxide layer developing on its outer surface. The hardness of the oxide layer may exceed 1000 HV (70 HRC), making it much harder than the base material. Research has shown a general trend of increasing oxide layer hardness of tubulars delivered from the mill, with average values trending from 510 HV - 600 HV (50 HRC - 55 HRC) more than a decade ago to 1000 HV (70 HRC) today. The impact of this finding upon handling and running of 13Cr tubulars, and those of similar quenched and tempered alloys, is apparent when considering the equipment commonly employed for such operations.

Conventional handling and running technologies use case hardened (carburised) inserts and dies. The carburising process applied to the steel substrate imparts a surface hardness generally ranging between 600 HV - 750 HV (55 HRC - 62 HRC) that decreases with depth until the core hardness, typically 300 HV - 380 HV (30 HRC - 39 HRC), is reached. These properties enable dies and inserts to penetrate and grip tubulars with oxide layers at the low end of the scale, but not so for tubulars with oxide layers at the high end. In the latter instance, die and insert teeth have been shown to fracture and wear prematurely, ultimately resulting in slippage or dropping of the tubular string.

New technologies exist that overcome this issue. For example, Frank's Fine Point™ technology has been shown to effectively and reliably penetrate even the hardest oxide layer without fracture or wear. This was made possible through geometric optimisation to generate optimal contact pressure and the development of a proprietary metallurgical treatment that promotes hardness while maintaining necessary toughness. Other technologies rely upon friction or mechanical interference between the gripping component and the tubular (e.g., Frank's Fluid Grip® and Collar Load Support (CLS™) systems, respectively). These technologies also offer the additional benefit of being completely non-marking, eliminating mechanical damage that can lead to premature tubular corrosion and failure.

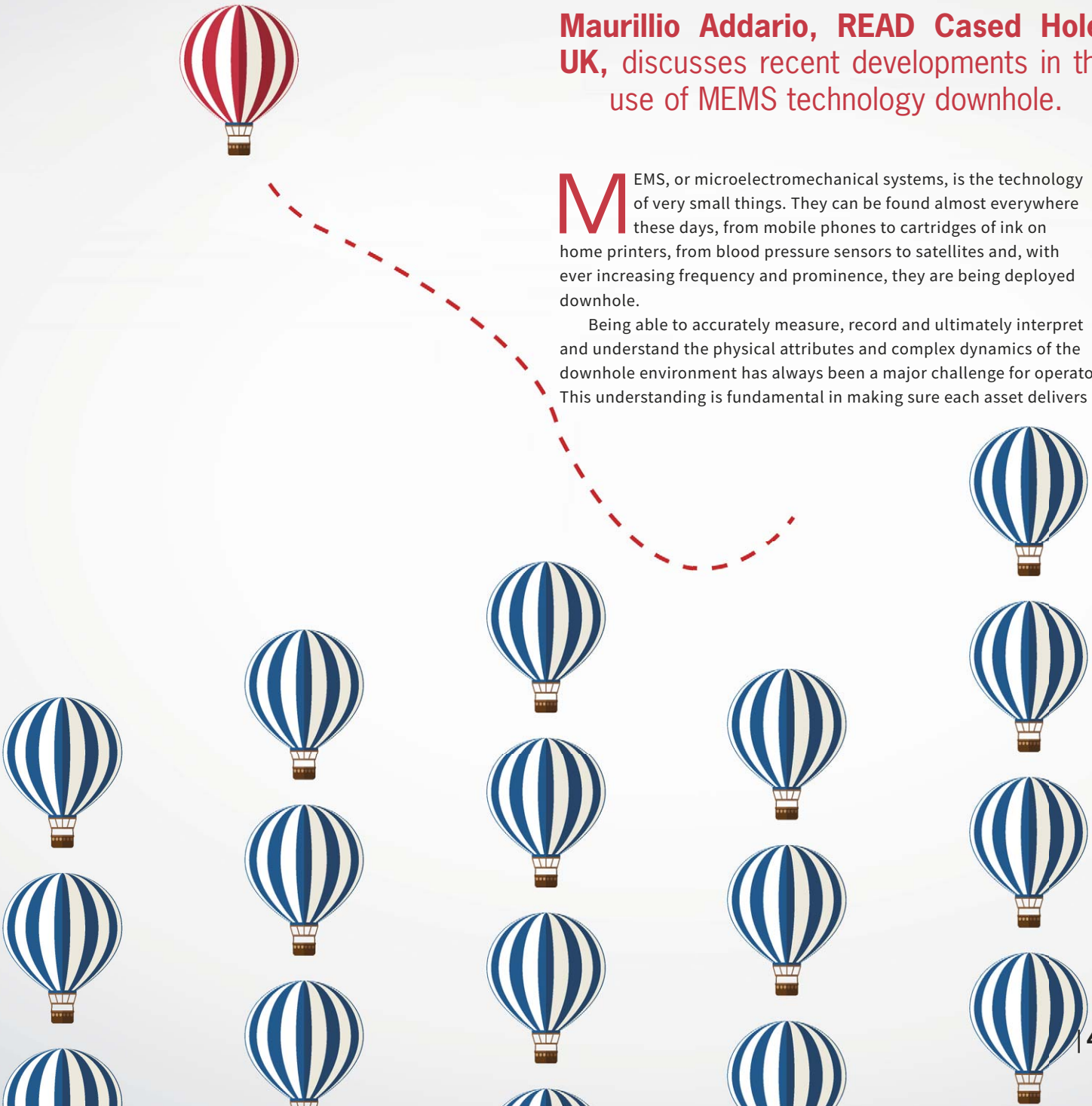
CARBO – TERRY PALISCH

CARBO's expertise within materials science and manufacturing enabled it to develop the most conductive and durable proppant technology in the market that significantly improves overall fracture conductivity, resulting in less erosion, more production, increased recoverable reserves and greater returns for the operator. Utilised by all super major E&Ps operating in the Gulf of Mexico, KRYPTOSPHERE HD technology is an ultra-conductive, high-density ceramic proppant, specifically engineered for high closure stress and risk environments, including ultra-deepwater regions such as the Gulf of Mexico. Precision-engineered, strong, durable, round, single-mesh-sized and smooth proppant grains avoid the creation of fines to ensure high conductivity across the entire range of low to high stress well conditions. It exceeds the conductivity of existing bauxite-based high-strength proppant and reduces costly wear-and-tear on pressure pumping equipment, ultimately providing higher production and EUR.

The ceramic technology creates a frac with more space for hydrocarbon flow, maximising the operator's return on investment. Whereas KRYPTOSPHERE HD technology is specifically engineered for offshore applications and very deep well applications, KRYPTOSPHERE LD has been developed for onshore applications and moderate to deep wells. The LD technology is engineered to have the same characteristics as the HD technology but in addition, the LD technology provides higher conductivity, improved proppant transport and increased propped fracture volume compared to intermediate-density and bauxite ceramics.

In order to build the most optimal solution for a variety of different well challenges, KRYPTOSPHERE has been designed to serve as the base ceramic technology, or to be otherwise integrated, with a range of additional technologies to enhance proppant functionality, such as flowback/fines control, pack integrity and frac fluid clean-up. The ceramic works in conjunction with resin coating technology, proppant pack consolidation and relative permeability modification technologies.

CHANGING THE GAME



Maurillio Addario, READ Cased Hole, UK, discusses recent developments in the use of MEMS technology downhole.

MEMS, or microelectromechanical systems, is the technology of very small things. They can be found almost everywhere these days, from mobile phones to cartridges of ink on home printers, from blood pressure sensors to satellites and, with ever increasing frequency and prominence, they are being deployed downhole.

Being able to accurately measure, record and ultimately interpret and understand the physical attributes and complex dynamics of the downhole environment has always been a major challenge for operators. This understanding is fundamental in making sure each asset delivers

long term financial results, extending and maximising recovery being as much, if not higher priority than minimising costs.

In this context, the evolution of sensor technology currently available has come a long way from the first resistivity logs, with an ever increasing gamut of choice going from simple mechanical caliper measurements, acoustic and magnetic investigation and many others, all the way to nuclear techniques. The latest chapter of this evolution now is being written by MEMS.

The technology

MEMS are created using the same integrated circuit (IC) techniques used to create just about every microprocessor, voltage regulator, FPGA and any number of other ICs out there in combination with micromachining processes. Ranging in dimensions from a few micrometres to millimetres, these tiny devices combine the ability to perceive, control and act on the micro scale with the capacity to respond on the macro scale.

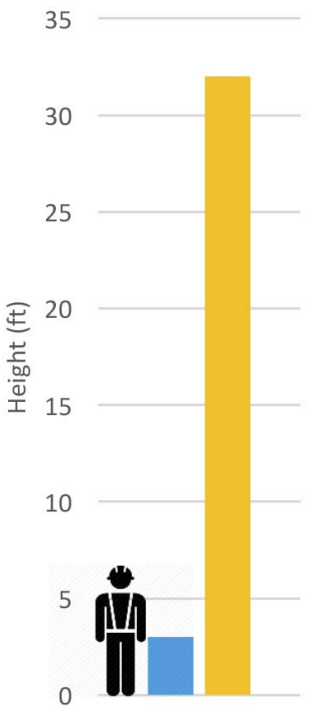


Figure 1. *Blue – FAST tool; Yellow – typical array PLT string.*

These incredibly minute 'machines' offer a number of advantages when compared to their standard electromechanical counterparts. Being in essence a solid-state solution they are inherently more robust, using less energy and performing more reliably and accurately in the harsh environments so common to the oil and gas industry.

Take for example quartz crystal resonators. These are common place in most devices. If it has a circuit inside chances are it has a timing device, an internal clock of sorts that is used to keep everything in check, and that timing device is almost always a quartz crystal that resonates at a known frequency. Quartz has many strong suits but it is no longer the go-to, obvious solution for every case and certainly not the only solution.

MEMS oscillators, for example, offer tangible benefits over quartz resonators in many areas. One advantage is that they can take up to 65% less PCB footprint, not requiring external components such as power supply decoupling caps. In the case of a particular 32 kHz quartz crystal, not needing the extra load capacitors can make the board for the MEMS solution three times smaller than the quartz equivalent.

There are quite a few other advantages too: being less prone to the adverse effects of electromagnetic energy; having much lower sensitivity to vibration – mainly due MEMS having a total mass thousands of times lower than the equivalent crystal counterpart; lower MTBF and DPPM; etc.

A new approach

For more than 30 years, READ Cased Hole has taken an active role in developing new technology. The company recognised how the many advantages of MEMS based downhole tools could prove a game changer for both well integrity and production logging solutions.

The technology of choice for READ's initial approach to the MEMS applications in the oil and gas sector was the Flow Array Sensing Tool (FAST). This particular downhole probe combines a variety of interchangeable sensors in the same mechanical platform, including pressure, temperature, micro-spinners, conductivity and optical gas-oil-water holdup amongst others. Due to its compact design and the extreme miniaturisation of its sensors, it is capable of replacing a typical array production logging string measuring over 30 ft with a single 3 ft long tool.

MEMS are being used extensively, with multiple sensors being based on that technology. Pressure and temperature measurements, for example, employ MEMS sensor instead of the ubiquitous quartz based measurement, where the resonant frequency of the crystal is affected by the borehole pressure and temperature. The casing collar locator (CCL), which is often a tool in itself requiring permanent magnets and wound coils, is replaced by a MEMS magnetic locator (MML), which allows for the clear identification of the casing collars, all with a footprint and power consumption that is orders of magnitude smaller.

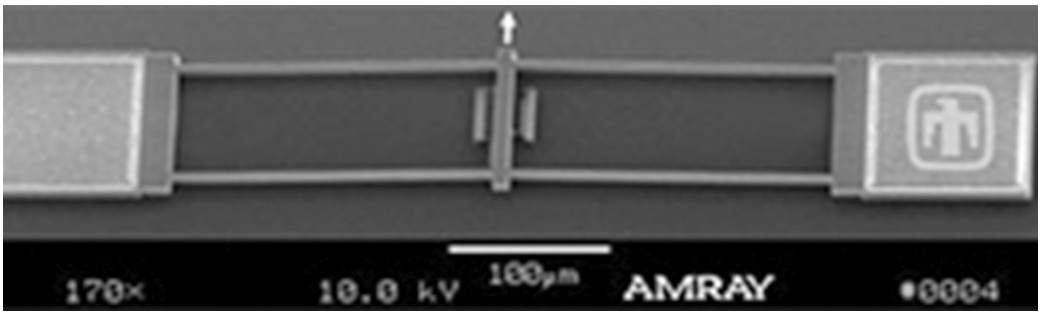


Figure 2. *V-shaped thermal actuator. The constrained thermal expansion of the angled beams results in the motion of the centre shuttle in the direction indicated by the arrow. (Image curtesy of Sandia National Labs).*

Figure 3. *FAST tool, which offers functional replacement for an entire 30 ft long array production logging string.*

Case study

Customers used to deploying the array production logging strings necessary to identify the zonal contribution of complex, often multilateral and highly deviated wells, have but a few images in their minds when they picture such toolstrings. They are very long,

often requiring a two-man team to safely handle them; they struggle where rig-up height is limited; they are very expensive and fragile.

It is not just cost and format limitations that help to make the case for MEMS based tools. New sensors such as an optical three-phase holdup available on the FAST platform also make a compelling argument. This particular transducer perceives ultra-fast changes in the refractive index of the fluid in contact with the tip of what looks like a small glass needle (it is actually made of synthetic sapphire). It works by computing the time the tip of the needle is in contact with either oil, gas or water and is able to count what it can determine to be bubbles on the majority phase.

One recent use of this technology came about when a customer needed a clearer picture of the gas-oil ratio (GoR) on a high rate producer. A suite of (MAPS) tools, one of the two de-facto standards when it comes to array production logging strings, was proposed. It included a resistance array tool (RAT – with 12 resistivity sensors) and a capacitance array tool (CAT – with 12 capacitance sensors) combined with multiple auxiliary sensors. In the same run a FAST tool configured with four optical three-phase probes was deployed in a memory mode below the MAPS.

READ's toolstring design in this instance was focused on delivering an extra set of sensors, the MEMS optical three-phase holdup, to offer additional insight in areas where both the CAT and RAT technologies would potentially struggle, namely the clear identification of the gas phase. This opportunity to deploy both MAPS and FAST technologies at the same time also offered invaluable comparisons between the datasets from each tool, allowing not only clearer identification of gas phase as per the customer's objective but also giving credibility to the newer technology by measuring it against the widely accepted MAPS results.

As predicted, the calculation of a gas holdup figure was made possible by the response of the FAST optical probes, which were much better at differentiating the gas from oil. This meant all the necessary data was acquired without the added risk of deploying a nuclear gas hold-up tool, which operates based on the emission of low energy gamma rays and the detection of the backscatter radiation.

Away from the areas where interpreting the free gas phase was more challenging, the log data acquired also revealed outstanding correlation between the MAPS and the newer MEMS based technology, reassuring the company that, in a scenario where the full MAPS string was to be replaced, they could deliver the level of accuracy and detail needed to make informed decisions fast and with confidence.

The next step

As the industry redefines itself, facing the challenges presented by the past few years with renewed energy and focus on new ways of delivering extended value from ageing assets, the quest to expand and enrich the industry's understanding, from the wellbore to the reservoir, has never been as important.

Staying ahead of the technology wave is all but the only way to deliver the answers necessary to underpin this understanding. To create the truly holistic model operators need to maximise reserve value, one cannot underestimate how fundamental the accuracy, reliability and the diversity of necessary data input is. All of these strands are deeply woven into the MEMS downhole revolution.

A Midland Basin Mystery

Joel Mazza, Carrie Glaser, & Ellen Scott, Fracture ID, USA, consider integrating measured high resolution geomechanics and petrophysics to analyse neighbouring well performance through a Midland Basin case study.

In the Midland Basin an operator drilled three horizontal wells (A, B, and C), all of which were drilled in the same formation and hydraulically fractured in a similar manner. Despite their geographic proximity and their similar hydraulic fracture treatments, the three wells showed different production responses. After they produced for several months, Wells B and C were noticeable underperformers compared to Well A. The operator indicated the presence of an offset producing well geospatially closest to Well C and furthest from Well A. This offset well had produced for over a year and likely depleted a significant volume of reservoir rock around it. However, the operator was uncertain to what degree the proximity to depletion was driving the production from Well A to be better than Wells B and C. Did Well A also have superior reservoir rock quality? The company tasked Fracture ID's Integration Team to investigate as Fracture ID had derived mechanical rock properties using its drillbit geomechanics technology for all three wells. To answer this question, the team utilised geomechanical properties from each well to build a mechanical facies model to characterise the reservoir and analysed the wells' fracture treatment responses.

Drillbit geomechanics

Today, oil and gas operators developing unconventional plays like the Midland Basin are drilling increasingly long horizontal wells. This facilitates the unique opportunity to describe and exploit the lateral heterogeneity of their reservoirs. The benefits of understanding this heterogeneity include optimising completions and thus increasing production. Recording and understanding this lateral heterogeneity, however, has proven difficult and expensive

when using conventional well logging programmes. The advent of drillbit geomechanics provides a cost-effective alternative.

Laboratory experiments show that interactions between a drillbit and the cutting of a rock can describe the rock's in situ geomechanical properties. Fracture ID processes and analyses accelerations at the drillbit to obtain mechanical rock properties and rock property relationships. The acceleration data is recorded in memory while drilling. The advantage of recording high resolution data while drilling is that no additional rig time is required.

A three component (3C), high frequency accelerometer is deployed behind the bit in the bottom hole assembly (BHA) while drilling. The 3C accelerations are processed and then converted to 3C stress and strain by applying techniques used in earthquake seismology.[1] These stress/strain relationships provide high resolution, in-situ rock properties along the wellbore in both vertical and horizontal wells. The results include high resolution (half foot), isotropic values of mechanical rock properties, Young's Modulus and Poisson's Ratio. Additionally, Fracture ID calculates bedding using a vertical transverse isotropic (VTI) solution and fracture Intensity using a horizontal transverse isotropic (HTI) solution. Figure 1 shows a typical geomechanical log provided by the company.

Method

Fracture ID's integration team has developed several workflows to optimise completions and provide reservoir characterisation solutions for lateral wellbores using high resolution geomechanical data. For this study, a petromechanical workflow was designed to leverage petrophysical resources and techniques applied to mechanical data to provide a predictive framework for mechanical behaviour. The key mechanical characteristics considered indicative of the economic efficiency of the well are drillability, fracability and producibility; the metrics used here to approximate these characteristics are mineralogic brittleness, strength (UCS) and stress. Each of these metrics are derived from the primary geomechanical log products described above. A mechanical facies model is then used to classify the wells into distinct rock types with predictable mechanical properties. Additionally, a lookback study using simple analytics was performed to assess if any depletion effects could be observed from the treatment responses that occurred during and after the hydraulic fracturing operations.

Petromechanical workflow

Basic mineralogy can be estimated from mechanical data combined with MWD gamma ray. Clay volume is calculated independently from gamma ray and from Fracture ID's VTI anisotropy (bedding). Comparison of the two clay volume interpretations provides relative estimate of kerogen content. Carbonate and Quartz are estimated on an uncalibrated basis in this example, and are not used further in the workflow, which seeks to reduce overall complexity.

In this example, mineralogic brittleness is calculated as a simple linear function of clay volume from VTI anisotropy. Unconfined compressive strength (UCS) is calculated from Fracture ID's Young's Modulus calibrated to horizontal, static values and converted to UCS through a series of empirical relationships.[2,3]

Figure 2 shows the simple petromechanical analysis for each well. UCS and brittleness are plotted against each other on the same track. Rocks with relatively high brittleness and relatively low strength are considered highly 'fraccable' and 'drillable.' Thus, values of relatively high brittleness and low strength have a positive crossover, shown in red. Values of relatively low brittleness and high strength have a negative crossover, shown in grey. Intervals of positive crossover are considered high quality rock or 'good rock' and intervals of negative crossover are low quality rock or 'bad rock'. Good rock is generally easier to hydraulically fracture and prop, resulting in a more conductive fracture network than treatments in low quality rock. When analysing the three laterals there is little notable difference in predicted minerology; however, when UCS and brittleness derived from measured geomechanics are compared, Well A contains a significantly larger percentage of good rock along the lateral. Well B contains a section of good rock in one third of the lateral with the rest of the lateral containing bad rock. Well C contains minimal good rock along the entire lateral. The results of this analysis aligned with the production responses with Well A being the best producer and Wells B and C being inferior. Fracture ID and the operator hypothesised that Well A's hydraulic fracturing treatment created a better fracture network than those of Wells B and C due to A's superior rock quality.

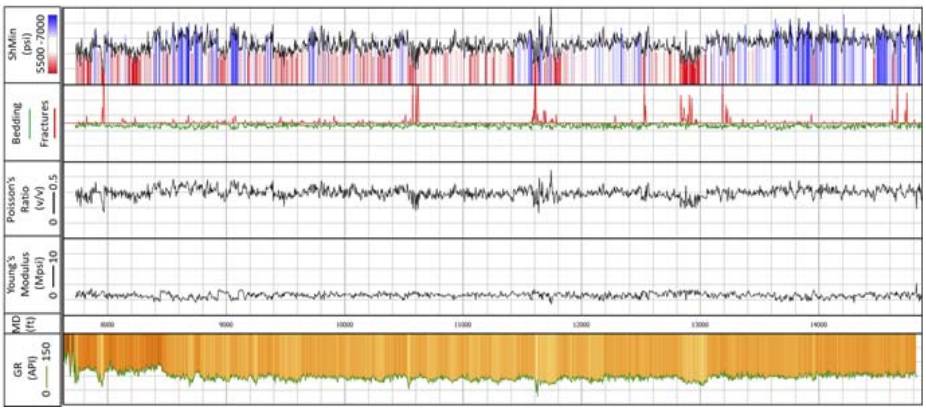


Figure 1. *Track 1: MWD Gamma Ray. Track 2: measured depth. Track 3: Youngs' Modulus. Track 4: Poisson's Ratio. Track 5: Young's Modulus. Track 6: fracture and bedding compliance and calculated ShMin.*

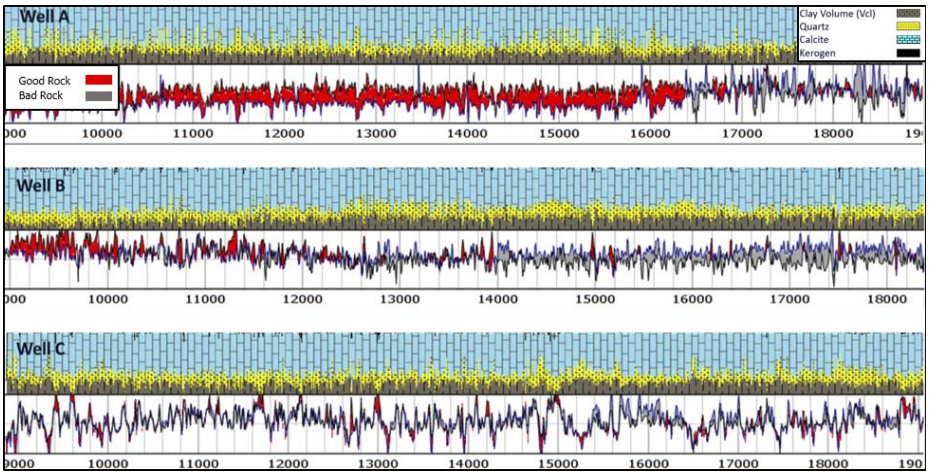


Figure 2. *Wells A, B, and C. Track 1: measured depth. Track 2: UCS (blue) and brittleness (black). Track 3: mineralogy.*

Mechanical facies

Mechanical facies help facilitate multi-dimensional analyses and can be used to predict mechanical behaviour. Facies were built on these three wells using the mechanical

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metrics discussed above (brittleness, UCS and stress). The goal of facies modelling is to provide a simple categorisation of expected properties that are commercially applicable to the specific target.

To complete the mechanical facies model, the minimum horizontal stress was calculated from Poisson's Ratio derived from the measured drillbit geomechanics along each of three wells' laterals. Using Equation 1 the minimum principal stress in an isotropic medium can be calculated.[4]

Equation 1:

$$\sigma_{hmin} = \frac{v}{1-v}\left(\sigma_{OV} + \alpha P_p\right) + \alpha P_p + strain\ terms$$

Where σ_{hmin} is the minimum horizontal stress, ν is the Poisson's ratio, α is Biot's coefficient, P_p is the pore pressure, and σ_{OV} is the overburden stress. Regional tectonic strain terms have been omitted in this study as variances along a single wellbore and its offsets are likely insignificant.

Incorporating the UCS, brittleness, and stress parameters, a self-organising map mechanical facies model was built. For this study, the data self-organised into six facies: red, purple, teal, navy, gold, and grey.

Figure 3 shows the mechanical facies results for the three wells. The distribution of the facies is derived from the percent contribution of each facies over each treatment interval. The treatment interval length was obtained by using top and bottom perforation depths for each stage. Well A has a higher percentage of red and purple facies, which indicates overall better rock quality. This aligns with the UCS and brittleness analysis result. Well B shows how the facies distribution differentiates between the red-shaded 'good rock' at the heel, where both strength and brittleness are high and the 'good rock' of Well A, where strength is particularly low. The navy facies, present primarily in the toe of Well C, is defined by relatively low stress, possibly indicative of depletion.

Fracture treatment analysis

The Integration Team analysed the pre-stage step-down rate tests and the instantaneous shut-in pressures (ISIP). The results confirmed the operator's suspicion that proximity to the offset producing well correlated with depletion effects. The pre-job ISIPs measured during step-down tests were notably higher and more consistent in Well A than Wells B and C. Well C had consistently lower ISIPs overall. Geospatially, Well A is farthest from the offset producing well and Well C is the closest. Low pore pressure, a result of depletion, will directly affect ISIP's according to Equation 1.

The step-down test is a diagnostic used to measure perforation efficiency and near-wellbore tortuosity before a treatment stage. The operator performed step-down tests on every stage of the three wells. On average, Wells A, B, and C showed relatively similar treatment efficiency results. Resulting perforation efficiencies were within 5% and resulting tortuosity values were within 10%. This suggests all three wells had equally-effective perforation and stage designs. Thus, the differences in production are likely driven by rock quality and depletion, not by any differences in completion designs.

The measured treatment parameters from step-down rate tests were used to calibrate values applied to the mechanical facies model to predict mechanical behaviour. Once trained with this workflow, the mechanical facies can be applied between drilling and completing future wells, predicting how each stage may treat. This could be valuable to an operator in cases where, for example, stages with high predicted tortuosity tend to have higher than expected treating pressures and a high percentage of screen-out events. Being proactive instead of reactive can give the operator insight ahead of a treatment which may result in less time and money lost from screen outs and less materials (chemicals, sand, water, etc.) utilised to complete a stage.

Conclusion

Extrapolating geomechanical properties for unconventional reservoirs from vertical to horizontal wells often results in inaccuracies from the low resolution of extrapolated vertical well data, and the resulting challenge of describing the heterogeneity of the rock. Operators typically assume these properties are constant across a formation due to lack of data or cost associated with acquiring this data. These errors are often compounded by maintaining these constant properties over several pads and sometimes sections. This is unfortunate because analysing geomechanical properties at a high resolution within even a single well demonstrates there is in fact a high degree of heterogeneity. These variances can be captured using accelerations measured at the drill bit and used to create petromechanical and mechanical facies models to more accurately describe the reservoir.

This study demonstrates a workflow in which measured geomechanical properties along a well can be used in conjunction with petrophysics to build predictive models. Additionally, these petromechanical properties can be grouped into facies to identify stage to stage differences along a wellbore. The accuracy of these models can be confirmed by analysing past completions. If the model is historically accurate and properly calibrated, it can be applied to predict how future wells may treat and subsequently produce.

The petrophysical and mechanical facies models developed for this study predicted that Wells B and C have lesser mechanical rock quality than Well A, resulting in lower quality stimulations. Thus, proximity to depletion was not the only reason why Wells B and C have lower production than Well A. Despite having similar mineralogical properties, the three wells showed significant differences in geomechanical quality.

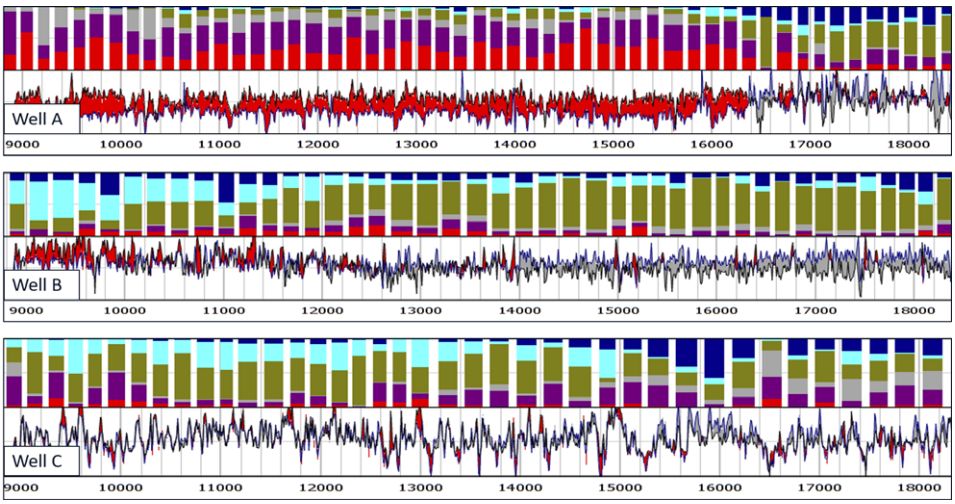

Figure 3. *Wells A, B, and C. Track 1: measured depth, track 2: UCS (blue) and brittleness (black), track 3: facies percent by stage.*

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Claire Kennedy Platt, Jeff Clausen, and Rohan D'Souza, NOV, USA, explain how a new development in drilling motor technology is increasing operational efficiency.

AHEAD OF THE CURVE

As drilling in shale plays has become more prevalent throughout the last decade, operators have relied upon rotary steerable systems (RSS) as a common top-tier solution to drill as efficiently as possible. With high complexity and lost-in-hole (LIH) costs, RSS can lead to expensive operations, increasing industry demand for a low-cost, low-risk mechanical tool for drilling curve and lateral sections. Drilling motor technology has evolved in recent years, but it has lacked the operational flexibility to change the bend setting downhole. In response to industry demand, National Oilwell Varco (NOV) developed the Vector™ Series 50 SelectShift™ downhole adjustable motor, which allows for enhanced directional performance and the ability to drill a curve and lateral in a single run. Adjustment of the motor bend setting eliminates extra trips and enables faster correction, increasing ROP throughout all sections of the well.

The downhole adjustable motor features two configurations, which include a straight-to-bent assembly and a bent-to-bent assembly, each with two position options. The straight-to-bent assembly offers bend setting positions between a 0˚ angle and high bend settings between 1.5˚ and 2.3˚. In the bent-to-bent assembly, the motor achieves up to a 2.8˚ maximum bend. Anticipated popular bend settings will include 1.5˚, 1.83˚, and 2.12˚. The straight setting of the adjustable motor limits hole tortuosity and aids in hole cleaning. By allowing higher rotary RPM and less side loading of the bit, the straight setting aids ROP and drills a more in-gauge hole. The motor significantly lowers rotary torque and weight on bit (WOB) requirements when rotating in the straight mode compared to the bent mode, thereby extending well reach.

NOV engineers built upon existing Vector Series 50 motor technology to provide high torque output capability, 100% flow to the bit, and reduced bit-to-bend length. Compared to previous technology, the downhole adjustable motor features increased seal longevity and bearing loads, handling up to a 50% increase in off-bottom bearing capacity. Engineered to withstand 35% more torque than previous generations of motor technology, the downhole

adjustable motor can be run on the strongest ERT™ power sections from NOV. Capable of handling flow rates ranging up to 700 - 750 gpm, the motor may be run on the highest flow power sections on the market. The universal joint design features torque-transferring faces and a driveshaft that is up to 25% larger in diameter, enabling higher torque capability and reliability.

The all-mechanical design offers bend setting options similar to directional motors. Operators adjust the bend angle to a high or low bend setting via RPM and flow changes in less than 2 minutes. A permanent pressure signal difference ranging from 150 - 250 psi on surface indicates the positions for bend setting confirmation. The MWD scribe stays the same for all bend adjustments. Combined with 100% flow-through-the-bit technology, this allows for maximum drilling efficiency. The downhole adjustable motor may be used for sidetracking, multilateral, lateral, and most directional applications. The current available tool size is 7 ⅛ in. for hole sizes ranging from 8 ½ to 8 ¾ in.

Case studies

Currently in the customer field trial stage, the SelectShift enables operators to increase efficiency and cost savings by reducing the number of trips required while also optimising critical drilling parameters and increasing operational flexibility. Engineers have tested the technology at the NOV Research and Development Test Center (RDTC) in Navasota, Texas, and Catoosa, Oklahoma. The downhole adjustable motor has completed more than 150 downhole shifts, drilling a total of 16 100 ft in five wells. With a maximum build rate of 18˚ per 100 ft, the motor has achieved higher rotary RPM in the range of 150 RPM in the straight mode in comparison to 40 - 80 rotary RPM, which is typically used with a bent motor.

During a Navasota test in December 2017, the operator used the downhole adjustable motor in a curve-to-lateral application, testing the straight-to-bend configuration. The motor drilled an 8 ¾ in. curve-to-lateral wellbore, hitting both positions and providing better build rates than expected. It dropped 0.5˚ in 800 ft in the lateral with no sliding. In total, it drilled 2750 ft in 75 hrs with an instantaneous ROP of 60 - 200 ft/hr. The motor kicked off the curve at 3300 ft and landed at 4900 ft and at 800 ft of lateral, completing 28 shifts during the run.

During another Navasota test run in January 2018, the operator used the same BHA configuration, drilling an 8 ¾ in. curve-to-lateral wellbore. The downhole adjustable motor drilled 2550 ft in 65 hrs. In this run, the motor kicked off the curve at 3300 ft, landed at 4400 ft at 80˚, and reached 600 ft of the 80˚ tangent. The motor achieved average ROPs of between 60 - 200 ft/hr, drilling the lateral and tangent at 150 - 200 ft/hr. Rotary drilling in the straight setting achieved 100 - 150 rotary RPM for 50% of the lateral. The straight setting demonstrated significant benefits when compared to bent motor rotary drilling at 50 RPM, showing less stick slip with lower WOB and torque values while achieving the same ROP. The motor achieved 16˚ per 100 ft and completed 35 shifts during the run.

NOV completed additional tests in Catoosa during March and June 2018, testing the straight-to-bent configuration for customer demonstrations. In several 8 ¾ in. dedicated curves and a vertical tangent wellbore in a hard limestone formation, the motor drilled a total of 4700 ft, confirming a build rate of 14 - 18˚ per 100 ft and basic function in hard rock with torques as high as 15 000 ft-lb applied to the motor. The motor demonstrated higher RPM capabilities in the straight mode. The testing provided a comparison of the effects on torque and drag when switching from rotary drilling at high RPM in the straight mode with the downhole adjustable motor versus rotary drilling at lower RPMs with a bent setting, as would be experienced with a conventional fixed bent motor.

The downhole adjustable motor further demonstrated ROP gains possible in straight mode at high RPM in the vertical-tangent wellbore, increasing ROP 50 - 70% at the same WOB when drill-off testing was completed in both modes in the same formation. The tool remained in the straight mode for most of the vertical-tangent run, and the bent mode corrected back to the proposed well plan as needed. ROP for this test held at an average 150 ROP throughout the run with sustained average ROP set as high as 380 ft/hr in the straight mode, finishing in less than 18 hrs. The performance validated for the tool's build rate, sliding performance, and new upgrades to longevity in harder formations. Longer duration field trials will follow.

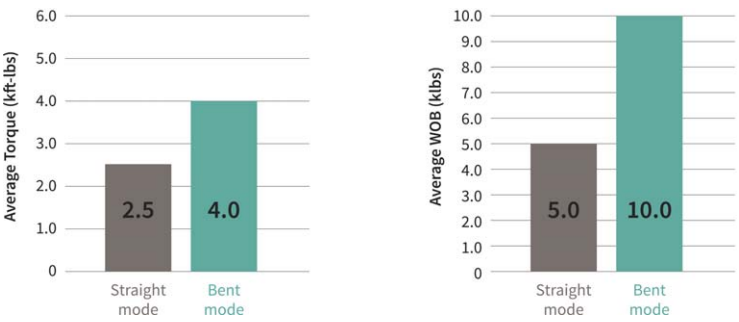


Figure 1. *SelectShift rotary drilling comparison (ROP fixed).*

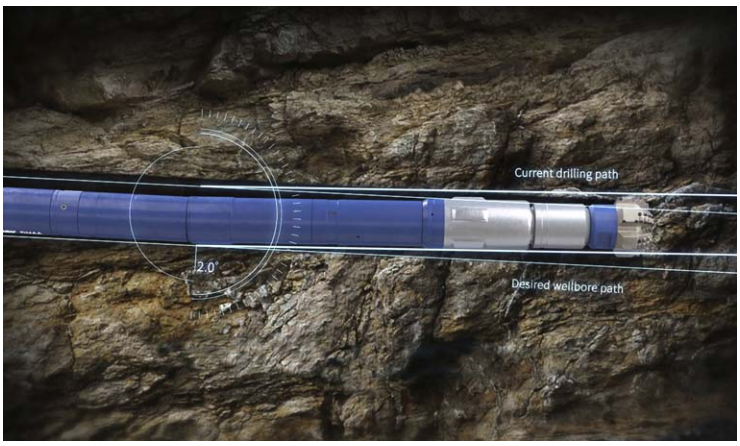


Figure 2. *Vector Series 50 SelectShift downhole adjustable motor.*

Conclusion

As the downhole adjustable motor undergoes field trials, NOV will continue running the motor in different well profiles and applications. With a focus on increasing ROP, reducing non-productive time, and reducing downhole vibrations while optimising critical drilling parameters such as torque and WOB, NOV will phase the Vector Series 50 SelectShift downhole adjustable motor's commercialisation based on well profiles and applications.

The proven record of field trials of the downhole adjustable motor opens new opportunities for drilling curve and lateral sections in a single run. Less torque and WOB requirements in the straight mode and lower bend settings can aid drilling in shale plays and extend lateral length by helping drillers avoid obstacles such as hole tortuosity, excessive sliding, and poor hole cleaning.

Increased flexibility to change the bend setting downhole meets a long-standing demand within the industry and has the potential to change drilling practices. By reducing the number of trips, increasing operational flexibility, improving hole quality, and optimising critical drilling parameters, this downhole adjustable motor can help operators increase cost savings and achieve more efficient drilling operations.

REIMAGINING SAFETY

Matthew Boucher,
Clock Spring Company, Inc., USA,
reveals how a different perspective on risk management can deliver creative solutions that improve worker safety.

The oil and gas industry today is safer than it has been at any other time in history, but statistics indicate that in the US, workers in upstream oil and gas operations have one of the highest accident rates across industries. Statistics from the US Bureau of Labor Statistics show the fatality rate for the oil and gas industry accounted for 71% of the fatal injuries in the mining, quarrying, and oil and gas extraction sector between 2003 and 2016 – this is despite having one of the most thorough safety training programmes.

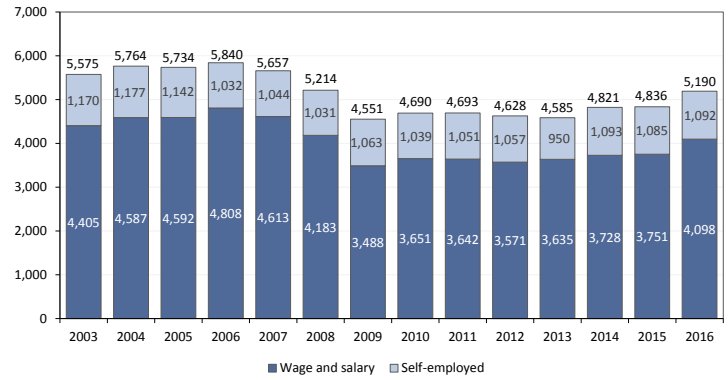
A huge amount of legislation and a long list of regulations have been put in place to address the dangers inherent to upstream oil and gas operations, and individual companies have invested millions of dollars in developing programmes that focus on behaviours and processes to improve safety culture.

With all the time and effort going towards improving worker safety, why is the number of lost time incidents, injuries and fatalities still high?

Maybe it is time to re-think the industry's approach to safety and reimagine how safety could be addressed to diminish the risk to workers.

A look back

Laws and regulations have made a dramatic impact on improving work conditions around the world. In the UK, legislation began changing the face of factories in 1833, when the first factory inspectors were appointed under the provisions of the Factories Act, which



- A total of 5,190 workers died from an occupational injury in 2016.
- This number increased by 7 percent from 2015 and is the highest count since 2008.
- Self-employed workers have consistently accounted for around one-fifth of fatal work injuries.

Figure 1. *US Bureau of Labor statistics data show that oil and gas industry fatalities made up 71% of fatal work injuries in the mining, quarrying, and oil and gas extraction industry in 2016.*

Figure 2. *Although New York City became the first state to pass a workmen's compensation law in 1910, two decades later, when the Empire State Building was under construction, worker safety still was not a top priority.*

Figure 3. *The Valemon Field is Norway's first platform to be remotely operated from land. Photo courtesy of Equinor. Photographer: Harald Pettersen.*

was formed to prevent injury and overwork in textile mills that employed child labourers. In 1840 a Royal Commission began investigating working conditions in the mining industry, and in 1895, a similarly tasked Quarry Inspectorate was formed to address safety in open pit mines.

The *laissez faire* approach to workplace safety that predominated at the turn of the 20th Century in the US meant injuries and tragedies were commonplace. The introduction to the workplace of chemicals, large-scale furnaces and other machinery created everyday hazards that workers had never had to contend with previously. Because responsibility for overseeing worker health and safety was a state responsibility, not the responsibility of employers, there was a lack of interest in creating a safe work environment.

In 1908, the US Congress passed the Federal Employers' Liability Act (FELA) – which applied to railroad workers in interstate commerce – to compensate railroad workers injured on the job. Despite the fact that railroad employers fought the adoption of a workers' compensation system for railroad employee injuries and severely restricted what an employee could claim, FELA became law. And even though the legislation was far from adequate by today's standards, it made injuries and fatalities more expensive for employers, who, as a result, began to pay more attention to safety issues.

In 1910, New York became the first state to pass a workmen's compensation law that automatically compensated injuries at a fixed rate instead of requiring injured workers to prove employers were negligent. There was a cap placed on the payouts, however; so even if the injury resulted in death or rendered the worker incapable of earning a living, the payout could not exceed US$10/week, and could only be collected for eight years.

Limited as this was, it represented a significant step toward improved worker safety and initiated the move for other states to follow suit. Between 1911 and 1921, 44 more states passed similar compensation laws.

In Norway, which today is viewed as a safety leader in the oil and gas industry, industrialisation came later, beginning around 1905. Originally, operational 'safety' took the form of posting medical personnel on work sites to deal with injuries, and it was not until 1917 that the focus changed from dressing wounds to proactively addressing workers' health. Though this was an improvement, there was no official legislation in place until the 1970s.

The same was true in the US, which took its next major step to improve worker safety in 1970, passing the Williams-Steiger Occupational Safety and Health Act federalising worker safety issues and creating the US Occupational Safety and Health Administration (OSHA) and the National Institute for Occupational Safety and Health (NIOSH).

In 1974, the Health and Safety at Work etc. Act was passed in the UK. It was the primary legislation addressing occupational health and safety in the country. The Health and Safety Executive, with local authorities (and other enforcing authorities) is responsible for enforcing the Act and a number of other Acts and Statutory Instruments relevant to the working environment.

Occupational health services were not regulated until 1977 in Norway, when the Norwegian Working Environment Act was passed, making preventive measures the primary

focus of company physicians and requiring all land-based operations to adopt a systematic approach to the work environment.

One of the biggest changes to legislation in the US took place much more recently, following the *Deepwater Horizon* incident in 2010, after which the US Department of the Interior formed two independent agencies to be responsible for offshore energy management and enforcement.

The Bureau of Safety and Environmental Enforcement (BSEE) enforces safety and environmental protection regulations for the offshore oil and natural gas industry on the US outer continental shelf. The Bureau of Ocean Energy Management (BOEM) is responsible for offshore renewable energy-related management activities and development.

The modern safety era saw the introduction of a law that makes Safety and Environmental Management Systems (SEMS) a requirement. SEMS II, a mandatory programme enforced by BSEE, is a tool that rig operators use to improve training and auditing procedures and empowers field-level safety managers with the authority to make safety management decisions.

These moves to legislate safety have had positive consequences, but the continuing occurrence of accidents, incidents, and fatalities illustrates that laws and regulations, even if they are followed to the letter, cannot eliminate all risk.

All the work to improve safety done to date has focused on mitigating hazards, not removing them. If legislation and regulations cannot fully eliminate fatalities in the oil and gas industry, what can companies do to reduce the risk of injury and accidents?

Continuing down the present path is not going to lead to a different destination.

Implementing change

A disruptive change is needed to improve worker safety, and that change can take place only if the industry increasingly employs ways of working that do not introduce hazards in the first place. Eliminating hazards means working in a different way.

One of the ways companies have eliminated hazards is by introducing automation, which removes people from harm's way.

An example is National Oilwell Varco's NOVOS reflexive drilling system, which was awarded an OTC Spotlight on New Technology Award for 2018. NOVOS automates repetitive drilling activities like making a connection, coming off bottom, and managing specific parameters for circulation and weight-on-bit. This allows human drillers to focus on consistent process execution and safety and benefits operators by optimising drilling programmes. According to the company, NOVOS delivers greater consistency for every driller, regardless of a worker's experience level, repeatedly delivering the same improved performance. By providing precise control and customisation, the system removes some of the opportunities for mistakes. Consistency improves performance, which means there is minimal disruption to drilling activities and no risk of mistakes being made during a shift change.

Automating activities works, but it is not the answer to every challenge. Sometimes, the solution is found in developing ways to work remotely. This is something Oceaneering has achieved with its newly introduced E-ROV, which also won a 2018 OTC Spotlight on New Technology Award. The E-ROV is a self-contained, battery-powered remotely operated vehicle that uses a 4G mobile broadband signal transmitted from a buoy on

the water's surface. This eliminates the need for a surface vessel onsite and allows the E-ROV to be piloted from onshore using specialised remote piloting and automated control technology.

Norwegian operator Equinor, with partners Petoro, Centrica, and Shell, applied this same concept of remote operations to the Valemon Field, which is Norway's first platform to be remotely operated from land. Although Equinor has used land-based surveillance and control for offshore operations for some time, Valemon marks an important step forward because it was designed and constructed for remote control. The operators are using Valemon as a test case, gathering performance data to apply lessons learned to other smaller platforms and fields.

Even when work has to be performed on site, there are ways to remove hazardous variables. In the case of repairs to risers, caissons, and topsides piping, risks can be eliminated by using composite materials instead of steel, which requires heavy lifting and welding, both of which introduce safety hazards.

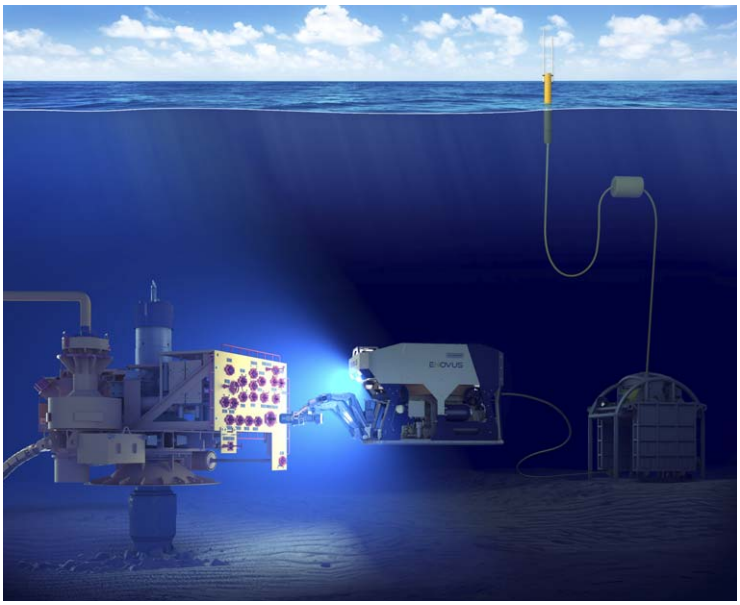


Figure 4. *The E-ROV improves safety by eliminating the need for a surface vessel onsite and allowing the unit to be piloted from onshore using specialised remote piloting and automated control technology. Image courtesy of Oceaneering.*

Figure 5. *Clock Spring composite repair sleeves arrive on site ready to install, eliminating heavy lifting and welding risks and delivering a completed repair in a matter of hours. Photo courtesy of Clock Spring Company, Inc.*

Using composite repair kits that arrive on site ready to install allows heavy lifting and welding risks to be removed from the equation.

Clock Spring Company, a provider of composite repair solutions, has found a number of ways to control fabrication and installation variables to manage risk. Clock Spring repair sleeves are manufactured in an ISO 9001 certified facility where the ratio of glass to resin can be verified. The unidirectional glass strands are positioned, pre-tensioned, and aligned, and the composite is wound, cross-linked, heat-treated, fully cured, and inspected before being shipped to the repair location. This is a key principle in product development – to design products that are easy to install and can deliver long-term, validated performance.

Focusing on controlling the weight of the products is critical because it is one of the ways of removing safety hazards. Workers can hand pass the sleeves during installation, eliminating the dangers associated with managing heavy equipment. The installation process requires no welding, so the physical risks associated with welding are removed from the picture. Such is the case with the recently introduced extended width Snap Wrap product for use offshore in what is one of the most corrosive naturally occurring environments. The composite repairs have been installed in this environment, delivering durable repairs.

Even when it is not possible to eliminate installation variables, it is important to mitigate them to the greatest extent possible. When executing repairs offshore, installers generally access the repair sites by being suspended by ropes. Using traditional repair methods requires workers to manage heavy components that have to be welded into place, which generally takes 2 - 3 days. Using composite products that arrive on site ready to install allows workers to execute a repair in a matter of hours. Composites have proven themselves in this environment, delivering successes that are a testimony to their viability for offshore repairs.

Taking the next step

It is time for industry to take a different approach to safety and to change the focus from legislating safety to eliminating the need to perform activities that can result in injury. The solutions that are available today have the potential to achieve that goal, providing ways to work that no longer endangers workers.

If the industry is serious about improving safety, it has to be willing to look at things from a different perspective and to adopt new ways of working, using products that offer safer installation without sacrificing quality and performance.

It is possible for companies to become better stewards of assets as well as the environment if there is a willingness to step off the beaten path and consider a different road forward.

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Duncan Greatwood, Xage Security, USA, discusses how blockchain technology is reinventing oilfield cybersecurity.

BETTING ON THE BENEFITS OF BLOCKCHAIN

Not every oilfield innovation comes directly from solving downhole drilling or production challenges – some occur completely outside the industry. For example, while the name Satoshi Nakamoto probably does not ring a bell, he invented what may become a standard for distributed cybersecurity in the oil industry: blockchain.

At its inception, blockchain had no connection to the energy industry, functioning instead as the public transaction ledger for cryptocurrency, including the most notable, Bitcoin. Due to its highly distributed nature, however, blockchain's unique value to cybersecurity has become increasingly evident. It allows distributed systems – such as the global energy industry, with its widely-dispersed equipment, facilities, instrumentation and people – to operate uncompromised.

No central failure point

What is blockchain's 'silver bullet?' With no single point of central control, there is no single point of failure. Due to its inherently distributed nature, blockchain allows mutual electronic collaboration among both people and entities without the need for a centralised system.

'Decentralisation' has been the key to blockchain's adoption by oil and gas. As decentralised trading operations became more visible, blockchain's appeal worked its way from trading rooms out to the field. As interactions with assets became more complex and remote access became more important, the figurative light bulb clicked on: having assets exposed virtually everywhere – and not hidden primarily in back room operations – was getting much riskier. More executives began asking the obvious: 'How can the industry implement a security technology as decentralised as the assets that it is trying to protect?'

As a result, blockchain is quickly going from a clever innovation with a techy name to the foundation for cybersecurity in oil and gas. In daily operations, blockchain's wide-ranging attributes help protect companies' interests in unprecedented ways:

Controlling access to critical equipment based on role and training

Although the knee-jerk reaction to wrongly configured systems is often that the action was maliciously planned, all too often incorrect controller configurations and settings are simply due to human error. For example, employees may not be properly trained or have a real understanding of how equipment should operate – yet any employee with an on-site controller's password can effect change – for better or worse.

Even lacking malicious intent, these actions can have a devastating effect on production and operational safety. The solution is to create a system focusing on each individual, their training level, and the equipment they should be allowed to access, configure and change. In brief, only those certified with the right qualifications should have access to equipment.

Blockchain is perfectly placed to hold and verify required worksite user identities and role-based policies – all tamper-proofed against accidental or malicious modification. Taking these practical steps has proven a strong security measure, improving both job efficiency and safety.

Figure 1. *It is critical that the integrity of oilfield devices, including field instrumentation, is not compromised.*

Figure 2. *The oil and gas industry is no longer paper-based. Utilising blockchain to securely and digitally hold all passwords protects against ransom attacks.*

Tamper-proof system security

From an operational perspective, it is critical that the integrity of oilfield devices, including field instrumentation, is not compromised. By design, blockchain's core characteristic is its tamper-proof nature as an immutable record. Therefore, companies can leverage blockchain to store device fingerprints and protect all their devices, including those with and without their own password protection.

By tamper-proofing all devices, including the software participating in the control system, integrity can be ensured throughout each device's lifecycle, from deployment through operation. In addition, the components of the operation can be cross-checked to make sure that no subsystem has been tampered with.

Thwart ransom attacks by giving operators total control

Ransom attacks can be as simple as an attacker installing malware on a pipeline's gauge and then threatening to overpressure the pipe, causing an explosion. However, this type of attack can be prevented by tamper-proofing devices like gauges, as well as controlling device access with a tamper-proof blockchain-protected login system.

Operators can utilise blockchain to securely and digitally hold all passwords and protect against ransom attacks by requiring login via the blockchain before a device can be accessed. With blockchain, companies now have a tamper-proof record to compare against deployed software binaries and system configurations, ensuring that machines have not been damaged or compromised.

Expose dormant malware and recover from compromise through tamper-proof fingerprints; access logging, stale or stolen credentials via rotation

Operating as a data ledger, blockchain creates unchangeable records that maintain the integrity of system data. Companies are able to see where manipulations have taken place in a matter of seconds, identifying and isolating affected parts of the larger system, and preventing the spread of any cyber infection. Whether it is an access attempt, system change, or any other potential circumvention, blockchain can hold a tamper-proof log of transactions for each gateway. With the blockchain's 'single source of truth,' there is always a place to go for restoration or healing.

With the blockchain providing a failsafe and tamper-proof way to store device passwords, it becomes possible to rotate passwords at scale. Password rotation will expose installed malware that is still using obsolete or stolen passwords, enabling immediate detection and rectification. Similarly, blockchain provides the foundation for auditable access logs and fingerprint checking, so attackers can no longer operate undetected. Furthermore, since blockchain is inherently self-healing, if some nodes are compromised, then the majority of healthy nodes will isolate compromised nodes. The compromised nodes will not be able to change security policies or insert new user identities – techniques commonly used to gain access to control systems during a cyber-attack.

In summary, because blockchain provides a full immutable record of all transactions taking place in the system, it is no longer possible for an attacker to disconnect a controller from the network, manipulate its capability, then re-connect it, with the company possibly not even knowing that something has occurred.

Replication (copy of critical security information) and redundancy

Blockchain can also facilitate the replication of one node to another, which is typically done to provide redundancy for nodes that are damaged or destroyed. This means that many components of the larger oil and gas network retain copies of security information, enabling the reconstruction of passwords and historical operation logs.

Replicating this information from the field to the cloud makes it readily available in a corporate reporting environment. In daily operations, if one or more computers are damaged or even destroyed, the information can be easily reproduced in the field to get the system up and working again. In other words, replication is one of multiple protections against a single point of failure.

Inventory of assets, software versions, theft control, and rogue device control

One of the blockchain's most obvious, but often overlooked, characteristics relates to the oil industry's physical structure which, having been built over decades, creates a real security problem. Spread across the industry's global operations is a wide variety of controllers, HMI, and SCADA systems. Consequently, detective work is often required to determine what constitutes the asset inventory.

There are several daunting tasks that follow initial inventory: did operators receive what they thought they bought? How many devices were swapped out? How many were added? Only recently has this exhaustive manual inventory become automated to compile device types, their functions, manufacturer names, and which version is being run. This digital inventory can then be mapped out across the territory and inserted into the blockchain database to ensure it becomes a permanent record subject to modification exclusively through the system. Through this process, anything that does not match the inventory, device, or event transaction through authorised devices will trigger the system – resulting in immediate detection of new, rogue devices or malicious actors. Again, blockchain acts as the tamper-proof system-of-record for equipment inventory.

Strength in numbers

An old saying haunts traditional cybersecurity – 'the more connected things a company has, the worse off they are.' In other words, traditional security systems are 'only as strong as the weakest link.' This warning especially hits home when companies realise that their operations are made up of hundreds or even thousands of connected devices and controllers.

With a blockchain-protected system, however, the more nodes, the stronger the system. An attack can only be successful if the majority of nodes are compromised simultaneously. But because the components of the blockchain-protected network are constantly verifying credentials and corroborating access attempts with group consensus, renting or buying more assets for a system does not make it more vulnerable. Instead, the system becomes better protected as a 'strength in numbers' effect takes hold, locking out unverified users or attempts to breach the system.

Safety, fewer site visits, and better controlled visits

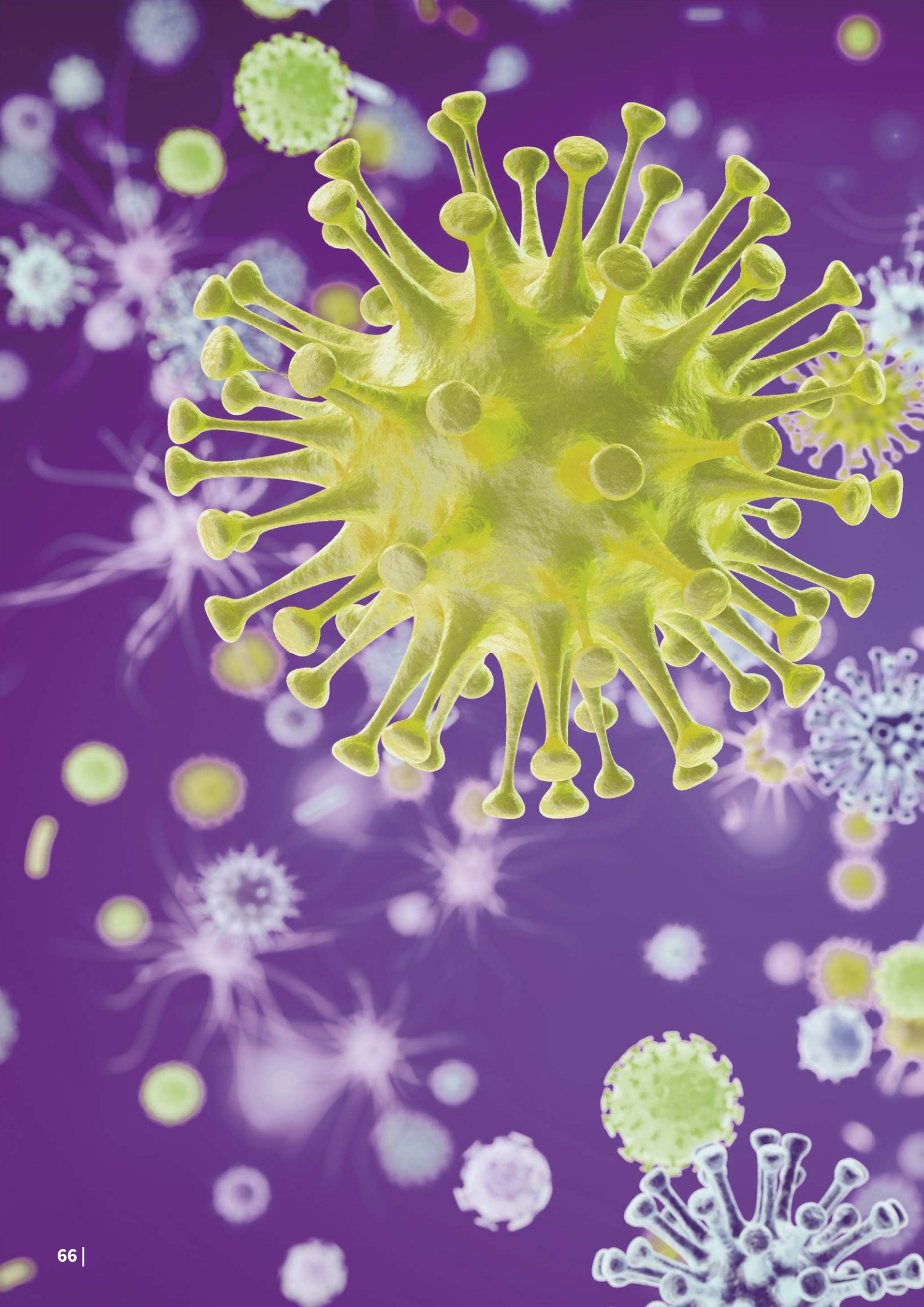
Many safety issues for oil and gas companies are directly related to the human factor. Thus, when it comes to the safety of personnel, one way to reduce liability and avoid on-site injury is by doing more work remotely instead of on-site. Automating instrumentation and maintenance tasks can be helpful to daily operations, but requires access into the networked assets, which can expose operations to cyber risk. Blockchain meets these challenges head-on by networking and automating security without creating vulnerability. As blockchain protection is established in the field, extensive remote activity such as remote control and remote monitoring of assets becomes not only possible, but practical and efficient.

Looking forward

Blockchain is primed to be the foundation of new industrial innovation, not only throughout oil and gas operations but in many other significant global industries as well. With its immutable foundation, blockchain can help companies secure almost anything.

Houston-based oilfield technology company GlobaLogix has had a front row seat to the increasing security concerns of the midstream and upstream oil and natural gas sectors. "The IoT revolution – with all its anticipated benefits for producers – needs more than vision. We need to implement failsafe protection for every wellpad, gathering system, and pipeline, or fall victim to a maelstrom of hacking and malware attacks," said Chuck Drobny, GlobaLogix CEO. "Existing security approaches just don't cover the bases for this geographically dispersed industry so critical to economic prosperity and national security. As the ultimate trust mechanism, blockchain assures control and traceability at every level, however complex or dispersed. Blockchain will have a bigger impact on the energy industry in the next five years than the Internet has had in the last thirty. The time to start is upon us."

Blockchain's dynamic combination of attributes – providing robust decentralised security enforcement, enabling remote access, and functioning as the 'single source of truth' without creating any one single point of failure – all combine to create tamperproof, self-recoverable, and redundant protection against cyber threats worldwide.



SAYING GOODBYE TO BACTERIA

Marcus Davidson and Sherrill Gammon, Kemira, discuss the long-term preservation of water-based drilling muds.

Microorganisms are found almost everywhere. In the oilfield, they may be native to the reservoir but can also be introduced from external sources such as drilling muds, hydraulic fracturing waters or injection waters.

Drilling fluids or muds are an essential component for drilling almost all oil, gas and injector wells. Serving a wide range of functions including, but not limited to, cooling and lubricating the bit, removing rock cuttings from the well bore and controlling downhole pressures. Maintaining fluid properties, such as viscosity and fluid loss, is essential for ensuring the drilling fluid both cleans the hole and keeps downhole pressures under control. Water-based drilling fluids can be formulated with many components including polymers, both natural and synthetic, clays, barite, salts and other additives to achieve the desired mud properties. These additives can often be both a source of bacteria, many times in the form of bacterial endospores, as well as a source of nutrients to allow those bacteria to thrive.

If left uncontrolled in the drilling mud, microorganisms including general aerobic and anaerobic bacteria, sulfate reducing bacteria (SRB), acid producing bacteria (APB), fungi and others can pose significant operational issues. Along with offensive odours, the resulting bacterial action can directly impact mud degradation of fluid properties such as viscosity/rheology, pH and fluid loss. This can lead to complications, such as poor hole cleaning, loss of fluid control to the wellbore, generation of volatile organic acids, and gases such as methane and hydrogen sulfide, all of which ultimately affect the life of the well. Additionally, the introduction and proliferation of these microbial populations can result in reservoir contamination and blockages, microbial induced corrosion (MIC) and reservoir souring.

Bacterial control

The selection of appropriate biocides with the correct application is the key for controlling microbial activity and growth within the fluid. In drilling, bacterial control may be needed in the mud for extended periods of time, from days in storage tanks to weeks of active drilling where fluids are recycled and come into contact with the reservoir. Effective control of these microbes and their activity will provide operational benefits that ensure long-term preservation of oil and gas production zones to asset integrity of process equipment and pipelines.

The use of biocides to control bacterial populations in drilling traditionally favours a quick kill biocide, added continuously or with frequent batch additions to maintain the rheological and other specifications of the mud. Eventually control over the viable population will be lost. However, the use of preservative biocides, such as Kemira's AMA®-324 (dazomet) can provide an alternative approach to traditional quick kill biocides such as Glutaraldehyde, Tetra-kis-hydroxy-phosphonium sulfate (THPS) or 2,2-dibromo-3-nitrilopropionamide (DBNPA). A preservative biocide can be introduced during the drilling process, providing an effective dose that can control viable populations and substantially prolong the time until control is lost.

Mud preservation

AMA-324 preservative biocide has been used to control viable bacterial populations in a number of oilfield applications. The chemistry is widely used in hydraulic fracturing fluid packages; for preservation in tanks and pipelines and in drilling operations for the preservation of water-based muds. The biocide has been shown to control the growth and activity of specific problematic microorganisms such as APB and SRB, as well as control the development of microbial biofilms. The biocide is an effective, broad spectrum antimicrobial agent well suited for water-based drilling fluids. The preservative biocide targets proteins, replication enzymes, or metabolic enzymes, which are present only in active viable bacteria that are alive and capable of reproducing.

Evaluating bacteria in mud

A laboratory study was carried out to determine the impact of bacterial populations on a water-based drilling mud and the efficacy

of the biocide. The evaluation was carried out on a field sample of water-based mud and a dry mix of the mud components.

Samples were initially tested to determine the bacterial types present:

- The field mud sample contained a high percentage of non-endospore general heterotrophic aerobic bacteria, a small percentage of which were pseudomonas species and aerobic endospores. A small quantity of mould – 19 mould colony forming units per millilitre (cfu/mL) – was present in the field mud.
- The dry mix was found to contain general heterotrophic aerobic bacteria endospores, some acid producing bacteria and moulds. General anaerobic bacteria were also present and a small number of anaerobic SRB endospores.

Table 1 shows that the field mud and dry components contain a variety of micro-organisms with aerobic bacteria making up by far the largest proportion. The dry mix contains a slightly lower concentration of aerobic bacteria but the number of aerobic endospores is considerably higher. Endospores are a tough, dormant form of the bacteria that can survive hostile environments that would otherwise kill the vegetative bacteria cells. When added to drilling fluids endospores become a significant source of bacteria as the conditions for bacterial growth become more favourable.

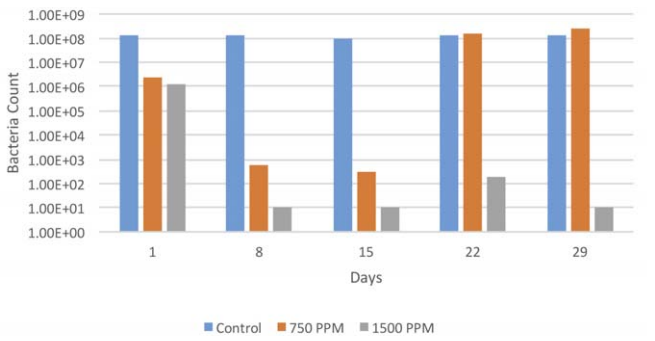


Figure 1. *Plot of Bacteria counts from a field mud sample incubated at 32 ˚C for 29 days. The treatment rates of AMA-324 were 750 and 1500 ppm. At 15 days, addition 1% of 10^6 bacteria were introduced as a challenge.*

Figure 2. *Laboratory bottle testing to determine bacteria biocide effectiveness – 1% TDS Phenol Red media bottles.*

To evaluate the efficacy of the preservative biocide drilling mud samples were treated with 250 to 1500 ppm of preservative biocide and incubated along with an untreated control sample for 28 days at a constant temperature of 32˚C while gently rotating. Samples were periodically collected for testing. Results showed that AMA-324 was effective at controlling growth of aerobic bacteria over 28 days versus the control. After 15 days, additional bacteria were introduced to the system as may occur in the drilling environment when either product is introduced to the mud or bacteria is introduced from the formation being drilled.

The data shown in Figure 1 confirms that AMA-324 is a slower acting biocide that takes more time than traditional biocides to begin acting. After eight days incubation, the bacteria count of the fluid has been reduced considerably versus the control sample from 10^8 to below 10^3. At a 1500 ppm dose rate effective control is maintained past 29 days even with the addition of 1% bacteria at 10^6 at 15 days. This capacity to control bacteria growth even with the incorporation of additional bacteria loading is beneficial in a drilling mud which will encounter bacteria additions from numerous sources. Bacteria will be added from dry components such as clays and barite and from the water used to make the drilling fluid. Effective control of bacteria is also seen at the lower concentration of 750 ppm, although additional biocide treatments may be required after 15 days. In the mud used in this study the main components were inorganic minerals such as barite, bentonite and other clays and smaller amounts of polymeric dispersants or mud thinners. Although bacterial action would not be expected to have a major impact on fluid properties, they can generate acid gases and other volatile materials that can cause pH changes that will affect the behaviour of the fluid. Degradation of the mud thinner will negatively impact fluid rheology and fluid loss control as the clays used to build viscosity will tend to flocculate as the pH drops and the thinners are consumed.

The susceptibility of water-based muds to bacterial action can limit their useable lifespan. The use of an effective long term preservative biocide means that water-based mud can be reused more often and can be effectively stored until required in much the same way as oil based muds.

The application of biocides in water-based drilling muds is a well-accepted method for controlling microbiological growth and maintaining the fluid specifications such as rheology and fluid loss. Preservatives are providing an alternative to traditional biocides used in water-based drilling operations. They provide longer term microbiological control in drilling fluids for those held in storage pits or muds that are being recycled during drilling operations. The correct selection and application of drilling biocides can ultimately extend the life of the drilling fluid and the life of the well.

In summary

Bacterial contamination of drilling fluids is inevitable and can significantly shorten the useable lifespan of the fluid and its ability to perform critical functions such as suspending solids and balancing downhole pressures. The use of effective long acting preservative biocides such as AMA-324 can significantly enhance the control of bacterial growth versus untreated drilling fluid. Effective at low treatment rates and with no impact on fluid properties this is well suited for the long-term treatment of most types of water-based drilling fluid systems.

Table 1. Bacterial analysis of a field mud and dry mud mix used in drilling (in cfu/mL).

Description	Aerobic bacteria	Aerobic endospores	Aerobic pseud. species	General anaerobic bacteria	Fungi	APB	SRB in 1% postgate	SRB endospores in 1% postgate
Dry mud components	3.9 X 10^6	5.6 X 10^5	0	>10^4	1200 mould	<10^1 from a 1:10 dilution	10^1 from a 1:10 dilution	<10^1 from a 1:10 dilution
Field drilling fluid	4.7 X 10^7	110	420	150	19 mould	Not done	10^2	10^2

Dr. Ming Yang, TUV SUD NEL, UK, discusses a joint industry project that aims to make online oil-in-water monitors for produced water discharge reporting commonplace.

POLICING PRODUCED WATER

Produced water is a by-product of oil and gas production. Once the produced water is brought to the surface, it is treated and then discharged and/or re-injected or reused. According to the International Association of Oil and Gas Producers (IOGP), for offshore oil and gas production, worldwide roughly three-quarters of the produced water is treated and discharged.[1] In the North Sea, 413 million m^3 of produced water

was officially produced in 2014 of which 324 million m^3 was discharged.[2]

Discharge of produced water to the environment is strictly regulated. Oil present in a discharged produced water is one of the key parameters against which performance standards are usually set. In the North Sea, this is linked to the 'dispersed oil' as measured by the OSPAR (Oslo-Paris Commission) Gas Chromatography and Flame Ionisation Detection (GC-FID) method, for which the current standard is set at 30 mg/l (monthly average).

Both GC-FID and other laboratory based methods are used to determine the oil in produced water level for compliance monitoring and reporting. Online oil-in-water monitors have been used for process control and monitoring purposes, but few have been used for compliance monitoring to date. Yet, there is a strong need to push the uses of online monitors for reporting due to an increased level of interest in oil and gas production using unmanned and subsea production systems. A joint industry project (JIP) is therefore being initiated, aimed at making the uses of online oil-in-water monitors for produced water discharge reporting a common practice.

Existing sampling requirements

Depending upon the types of oil and gas production installations and the amount of dispersed oil-in-water that is discharged per annum from the installations, sampling requirements may vary from one installation to another. Table 1 provides a summary of these requirements according to the OSPAR.

In the UK, more specific requirements detailed in its BEIS (Department for Business, Energy and Industrial Strategy) guidance are provided.[3] These requirements are summarised in Table 2.

Table 1. Oil in produced water sampling requirements by OSPAR.

Manned Installations that discharge continuously	▸ A minimum of 16 samples per month. ▸ Samples taken at equal time intervals. ▸ Samples taken after the last item of treatment equipment in a turbulent region. ▸ Method of sampling yielding equivalent results approved by a competent authority can be accepted.
Unmanned or with batch or small discharges	▸ The frequency and timing of sampling should make sure that samples are representative of the effluent, taking into account operational aspects and logistics. ▸ Small discharges refer to discharges of no more than 2 tpy of dispersed oil.

Table 2. Oil in produced water sampling requirements in the UK.

Discharge quantity per annum	Types of Installations	
	Manned	Unmanned
Less than 2 t	A set of samples collected and analysed at least once a month.	One set of samples taken during each visit and analysed.
More than 2 t	At least two samples collected at approximately equal time intervals and analysed per day.	Not foreseen and unspecified. Requirements to be agreed on a case by case basis.

In short, for manned installations that discharge produced water continuously (of more than 2 tpy of dispersed oil) a minimum of 16 samples is required to be taken at the OSPAR level. However, at the individual country level within the OSPAR, e.g. UK, samples are taken at least twice per day at equal time intervals.

Current measurement practices

For compliance monitoring and reporting, oil in discharged produced water must be reported in terms of the OSPAR GC-FID method. Thus, for installations that discharge continuously and are not categorised as unmanned or small discharges, samples taken must be analysed by the OSPAR GC-FID method or a method that would produce OSPAR GC-FID method equivalent results.

For installations well equipped with laboratory capabilities, the OSPAR method has been made available offshore, e.g. in the Norwegian sector. Analysis of oil in produced water can therefore be done directly by the OSPAR method. However, in the UK sector of the North Sea, operators have been using infrared absorption based methods, which are correlated to the OSPAR GC-FID method onshore.

Whilst both (GC-FID and infrared) methods have been practiced in the North Sea since the change of the reference method from an Infrared absorption based to a GC-FID based in 2007, there are issues and concerns. These may include:

For the OSPAR GC-FID method: the use of solvent, n-pentane, and pressurised gases, e.g. carrier gas, detector gas (hydrogen, synthetic air); also, the need for a skilled person to run such a method.

For infrared based methods: the use of tetrachloroethylene, which is suspected to be carcinogenic; also, the need for having to establish a valid correlation between the IR method and OSPAR GC-FID method.

For unmanned installations, regular (daily) sampling, analysis and reporting using the above approach will not be possible. As a result, to date, large continuous discharge of produced water from an unmanned installation has not been accepted.

Status of using online oil-in-water monitors

Online continuous oil-in-water monitors have been used by the oil and gas industry for many years. They have mainly been used for process trending and optimisation purposes to date.

Popular techniques used for online oil-in-water monitoring include:

- Light scattering.
- Laser induced fluorescence/UV fluorescence.
- Microscopy image analysis.
- Ultrasonic acoustic.

In recent years, a significant amount of effort has been made to develop water quality measurement sensors for subsea separation and produced re-injection or discharge applications. This has helped the advance of online oil-in-water monitoring technologies in terms of measurement accuracy and sensor reliability.

Online oil-in-water monitors can be accepted by regulators in the North Sea as long as the end users can demonstrate and prove that they can yield results equivalent to those obtained

by sampling and analysis using the OSPAR GC-FID method. Detailed guidance on how regulators may accept an online oil-in-water monitor for reporting has already been developed. Examples include the OSPAR Agreement 2006-6, the UK BEIS and the Norsk Olje&Gas O85 guidance.

To date, it is understood that two online oil-in-water monitors have been approved for the purposes of reporting oil in produced water discharge figures in the Norwegian sector of the North Sea. To the author's knowledge, these are the first applications worldwide of using online monitors for produced water discharge reporting purposes.

For unmanned installations, two papers were also presented at the most recent Produced Water Workshop event (organised by TUV SUD NEL) held in June 2018 in Aberdeen, UK. In both cases, discharge of produced water from an unmanned installation located in the UK Continental Shelf (UKCS) were considered. To allow for the discharge of produced water continuously in these installations, the uses of online oil-in-water monitor was considered necessary, as both anticipated that the total amount of oil discharged via produced water would be above the 2 tpy limit. There were challenges in using online oil-in-water monitors for produced water discharge reporting purposes. These challenges lie in the following facts:

- Lack of guidance.
- Lack of field experience.
- Few publicised cases or references available.
- Perception of poor performance of online monitors.

However, there has been clearly a genuine interest and support from the regulators to make the use of online oil-in-water monitors for reporting purposes a reality.

Benefits of using online oil-in-water monitors

There are many benefits in using online continuous oil-in-water monitors. These may include:

- Providing continuous oil-in-water concentration information for process control and optimisation.
- Spotting process upsets quickly.
- Potentially reducing the usage of solvents required by laboratory oil-in-water analysis methods.
- Reducing the number of manual samples taken for laboratory analysis.
- Likelihood of providing more accurate oil to sea discharge figures.

Online oil-in-water monitors provide continuous information on a minute by minute basis, if not more frequent. Thus, not only can one spot process upset conditions quickly and take actions to rectify the situation, but they can also be used for process optimisation, such as chemical dosing.

The use of online monitors will also significantly reduce the number of samples taken for laboratory analysis and therefore reduce the usage of solvents normally required for oil-in-water analysis. Furthermore, deployment of online monitors can potentially lead to more accurate oil in produced water discharge data compared to taking two samples and analysing them daily.

One may argue against the representativeness of having two samples taken per day, as opposed to the actual daily average discharge concentration. Preliminarily studies done at TUV SUD NEL have also indicated that there is an uncertainty associated with oil-in-water data obtained using the existing practice, i.e. by taking samples and then analysing them using the GC-FID method or an alternative method. This uncertainty may be as high ±50% (at 95% confidence level). The use of online oil-in-water monitors, in particular, those installed inline, could potentially reduce uncertainties linked to current sampling and analysis practice.

JIP initiative

With readily available oil and gas already produced in mature basins such as the North Sea, there is an increasing emphasis on maximising the recovery of remaining oil and gas reserves. Subsea separation and produced water re-injection (PWRI) and/or discharge, normally unattended installations (NUI), have all become increasingly considered by operators. As a result, there is a growing need to make use of online oil-in-water monitors for produced water discharge reporting purposes for surface (both manned and unmanned) installations and subsea applications.

A JIP is being initiated at TUV SUD NEL to fill the knowledge gaps, improve the existing guidelines, and make the uses of online oil-in-water monitors for produced water discharge reporting purposes a common practice. The scope of the JIP will aim as a minimum, to:

- Better understand uncertainties associated with oil-in-water manual sampling and measurements.
- Develop a more user-friendly set of acceptance criteria for accepting online oil-in-water monitors for reporting purposes.
- Develop guidance that would allow for accepting online oil-in-water monitors for unmanned and potentially subsea applications.
- Propose a set of changes to be made for the existing OSPAR, BEIS and Norsk Olje&Gas O85 guidelines in relation to using online oil-in-water monitors.

Whilst guidelines for using online oil-in-water monitors for produced water discharge do exist at the present time, these were developed with manned installations in mind. Under the existing guidelines, to accept results from an online oil-in-water monitor, a correlation is required to be developed between the online monitor and the OSPAR GC-FID method by taking parallel samples that are analysed by the GC-FID method. The correlation developed needs to be validated on a regular basis. The current validation process is time consuming and laborious.

In the case of unmanned installations, no guidance is currently available in terms of how to accept an online oil-in-water monitor for produced water discharge reporting purposes.

The outcome of the JIP will lead to better and simpler guidance for the global oil and gas industry, with which the uses of online monitors can be more commonly accepted not only for manned, but also for unmanned and subsea installations.

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