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Front cover
Designed and manufactured by C&J Energy Services in their Houston, Texas, Research & Technology Center, the new GameChanger™ perforating system was developed to eliminate misruns caused by common problems within traditional perforating guns.

The system has no ports that can limit access, crimp electrical connections or cause flooded guns. Plug-and-play connections eliminate wires running between guns, which reduces potential pinch points that can lead to misfires and associated nonproductive time.

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In Gardner Denver’s commitment to continuous innovation, we’ve reached another milestone — packing that withstands today’s high pressure fracking environments. We’ve reinvented packing by utilizing first principles in material chemistry and seal design. After extensive testing throughout the most challenging shale plays in North America, we can say with confidence that Redline Packing performs under pressure. Gardner Denver’s commitment to serve and dedication to partner with customers has led to this breakthrough technology entering the market.

**OUR FIELD TRIALS PROVED THAT REDLINE PACKING ACHIEVES**

1. Improved performance against heat, friction and pressure  
2. Significant reductions in scheduled maintenance time— as much as 50%— increasing fleet utilization and profits  
3. 2x the product life versus leading competitors according to customer reports
The Trump administration continues to move ahead with its goal of shuttering the Iranian energy industry and keeping roughly 2 million bpd of exports from reaching customers. The policy is part of a campaign pledge by President Trump to withdraw from the Iran nuclear deal ("one of the worst and most one-sided transactions the United States has ever entered into"), and reinstate sanctions on Iranian oil output.

The eventual impact of these sanctions is uncertain. A key difference between this round and the last being that the US will be acting alone, without the support of the EU. The previous round of combined US/EU sanctions saw roughly half of Iran’s 2.4 million bpd of exports removed from the market. In contrast, analysts initially predicted that the Trump administration’s sanctions would be considerably less effective.

However, the administration has taken a firm line on the issue with State Department officials highlighting that they do not intend to offer any waivers to companies or countries. This appears to be having an effect on the likelihood of compliance – Edward Morse, head of global commodities research at Citigroup, said that the sanctions “will be a pressure point on prices. What we’re seeing is more and more buyers of Iranian crude that are stopping buying, and this is going to accelerate.”

There are already the predictable rumours that new sanctions could send oil prices soaring to over US$100/bbl. Francisco Blanch, head of commodities and derivatives research at Bank of America Merrill Lynch, was quoted as saying, “We could risk adding 20-25% to the price of oil if some of the messages coming from the State Department are on point […] If the administration enforces compliance to zero imports from Iran we will likely have a very large spike in prices.”

Another factor supporting oil prices is Venezuela’s almost complete economic collapse. The country had been required to cut 95 000 bpd as part of the agreed OPEC cuts, but economic turmoil under President Nicolás Maduro’s tumultuous leadership has seen this figure rise to almost 675 000 bpd.

Indeed, prices appear to be so well supported that even OPEC’s June decision to begin reducing compliance with production cuts had seemingly little impact. As of May this year, OPEC countries had cut production by 147% of the agreed amount – with prices hovering around the mid-US$70s the group is now looking to reign in surplus cuts and return to 100% compliance.

It’s on the back of these higher prices that the upstream industry continues its gradual recovery. The journey isn’t over yet, but the omens look good for now. 

References
1. ‘US will be tough on Iran sanctions, and that could sting consumers’ – https://www.cnbc.com/2018/06/26/us-will-be-tough-on-iran-sanctions-and-that-could-sting-consumers.html
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Solid single piece construction
Maximum flow-by
Low friction
Lightweight
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Equinor chooses Nexans umbilical technology for its Askeladd development in the Barents Sea

Nexans has been awarded a major contract to provide complex umbilicals with power, fibre-optic and hydraulic elements for the next stage of the multi-phased Snøhvit development.

The Snøhvit gas field in the Barents Sea is the largest ever industrial project in North Norway. It is now entering part two of its multi-phase development plan with Equinor and its partners investing over half a billion euros in the Askeladd development which will provide feedstock for the onshore LNG (liquefied natural gas) plant at Melkøya in Hammerfest. To support the development, Equinor has awarded a major contract to Nexans to design, manufacture and supply a total of 42 km of static infield and interfield umbilicals to control the subsea production systems.

The Askeladd development, at a water depth of about 250 m, will supply 21 billion m³ of gas and 2 million m³ of condensate to the Hammerfest LNG plant, with production scheduled to come on stream towards the end of 2020. It will tie-in to the existing Snøhvit field infrastructure which features Nexans’ umbilicals installed in previous projects - including a 145 km umbilical that is still the longest umbilical in the world.

For the Askeladd development, Nexans will provide static subsea umbilicals with a complex cross-section comprising 3 kilovolt (kV) power, fibre-optic communications and hydraulic elements for chemical injection, together with a range of connection and termination accessories.

The electrical and fibre optic elements will be manufactured at the Nexans Norway facility in Rognan, North Norway with its 250 skilled and experienced employees. The contract would also involve over 50 local subcontractors and vendors. The complete umbilical system will be developed, manufactured and tested at Nexans Norway facility in Halden, Norway.

FairfieldNodal has changed its name to Fairfield Geotechnologies (Fairfield Geo). The name change reflects Fairfield Geo’s strategy and continuing evolution as a provider of life-of-field technology, data and solutions. FairfieldNodal pioneered the use of ocean bottom nodes (OBN) and is a leading provider of ocean bottom nodal technology, related services and data to oil majors, national oil companies and independent operators. The data and services are necessary to manage reservoirs, enhance productivity and mitigate risk over the entire life-of-field.

Fairfield Geotechnologies continues to build on a comprehensive OBN technology portfolio and has embarked on an aggressive programme to grow its capabilities through M&A and strategic partnerships.

KCA Deutag awarded contract on two platforms

Global drilling and engineering contractor KCA Deutag has announced that its offshore business unit has been re-awarded a new drilling contract on the North Alwyn and Dunbar platforms by Total E&P UK Limited (Total).

The contract is for the provision of platform drilling services and has an initial term of 3 years with an option to extend by a further 2 years.

Commenting on the contract award Rune Lorentzen, President of Offshore said: “We have been the drilling contractor on the Dunbar and North Alwyn platforms for approximately 20 years now, and are pleased that by working closely with our client we have yet again been able to offer them a cost-effective yet innovative drilling solution with a firm focus on crew training and competence.”

In brief

Australia

Central Petroleum Limited announces that drilling at the WM26 well continues without incident and is currently at 2274 m MD, with another 700 m to go. Logs will be run from 2360 m MD to evaluate completion options in the Lower Stairway 2.

Background gas continues to increase as more air drilled horizontal open hole becomes available. Natural permeability is low and further work may need to be considered to complete WM26.

Azerbaijan

BP and its partners in the Shah Deniz consortium have announced the start-up of the landmark Shah Deniz 2 gas development in Azerbaijan, including its first commercial gas delivery to Turkey.

The BP-operated US$28 billion project is the first subsea development in the Caspian Sea and the largest subsea infrastructure operated by BP worldwide. It is also the starting point for the Southern Gas Corridor series of pipelines that will for the first time deliver natural gas from the Caspian Sea direct to European markets.

Gabon

Panoro Energy has announced that following the progress on commissioning, the floating, production, storage and offloading (FPSO) vessel, BW Adolo has now left Singapore and is in route to the Tortue field, part of the Dussafu block offshore Gabon. It is expected that the FPSO will arrive in Gabonese waters in August 2018. The Tortue development project remains on course to deliver first oil at Dussafu in 2H2018.
WoodMac: Rise in new players in Southeast Asia’s upstream sector.

McDermott and BHGE win SURF and subsea contract for Myanmar gas field development.

Triangle completes static modelling at Cliff Head.

To read more about these articles and for more event listings go to: www.oilfieldtechnology.com
Horizontal wells are known to have production challenges as a result of inconsistent flow, damaging solids, and gas interference. Maximizing drawdown through the lifecycle of these wells often requires complex and expensive artificial lift strategies.

The HEAL System™ is a patent-pending downhole solution that easily joins to the horizontal as part of a standard well completion. It smooths flow from the horizontal, giving you the freedom to optimize your artificial lift strategy.

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- Simplify transition to artificial lift
- Accelerate transition from gas lift to rod pumping
- Improve performance in any artificial lift system
- Reduce capital investment and operating expense
- Proven technology in 250 installs in 37 formations
Seabed Geosolutions secures 4D monitoring survey contract in deepwater Gulf of Mexico

Seabed Geosolutions has been awarded a series of 4D ocean bottom node (OBN) seismic monitoring surveys over multiple oil and gas fields in the US Gulf of Mexico. The surveys, with a duration of around two months subject to final scope of work, will commence in the third quarter of 2018.

Stephan Midenet, CEO of Seabed Geosolutions commented, “With this recent award, we believe we have secured solid backlog for the CASE Abyss® crew and the Hugin Explorer vessel, while enabling us to work for a world class customer and placing our assets in a geographic market with substantial contracting opportunities. We are excited to be collaborating with this industry-leading customer for the first time in the Gulf of Mexico and look forward to a successful project.”

Seabed Geosolutions supports the optimal development and production of oil and gas fields by providing high quality seismic data collected directly on the seabed. These data are used for detailed reservoir characterisation, monitoring of the impact of production and detection of potential geohazards. With its global footprint, Seabed Geosolutions is one of the largest seabed geophysical data acquisition service providers with the broadest range of technology solutions for projects in water depths up to 3000 m.

Seabed Geosolutions is 60% owned by Fugro (and 100% consolidated); the remaining 40% is owned by CGG.

Honeywell announces new single platform

Honeywell Process Solutions (HPS) has announced Safety Manager SC, the next generation of its flagship Safety Manager platform. Its modular, scalable design enables it to function as a single platform for all enterprise safety applications, allowing customers – who are often using four or five different safety systems – to consolidate and reduce their training and engineering costs, and spare parts inventories.

Safety Manager SC incorporates a new Series C-based controller and Honeywell technologies such as LEAP®, Universal Safety IO, offline simulation and Experion® integration, which collectively simplify safety system engineering, development and testing.

Subsea 7 awarded contract offshore Angola

Subsea 7 has announced the award of a substantial contract by Total E&P Angola for the engineering, procurement, installation and commissioning of the subsea flowlines and umbilicals for the Zinia Phase 2 project, 150 km offshore Angola in water depths from 800 to 1000 m.

The contract scope includes the tie-back development of two reservoirs to the existing Pazflor FPSO in Block 17. Approximately 36 km of flowlines and 21 km of umbilicals will be installed, with offshore work scheduled in 2020. Project Management and engineering will be delivered from Subsea 7’s Global Project Centre in Paris, France and local office in Luanda, Angola. Fabrication will take place in Sonamet’s yard in Lobito, Angola. Subsea 7’s Regional Vice President for Africa, Gilles Lafaye, said: “This award recognises our cost-effective engineering solutions and our established local presence in Angola. We look forward to maintaining our long-standing and collaborative relationship with Total through our safe and efficient delivery of the Zinia Phase 2 project.”

IKM Subsea mobilising ROV to Johan Sverdrup

IKM have announced that Equinor has awarded IKM Subsea a services contract for ROVs on the Johan Sverdrup platform commencing Q3 2018.

The contract was won in a competition with other suppliers through an e-auction event that was performed as one of the final stages of the tendering process. The scope of work consists of provision of ad-hoc ROV operations to support drilling activities on the Johan Sverdrup field. The contract duration is 6 years with additional options.

“We are proud to be awarded the Contract for provision of ROV services on the Johan Sverdrup field and will continue to deliver high quality of services on a daily basis. This contract will also benefit of the 24/7 manned Onshore Control Center at IKM’s HQ, enabling the industry to save cost and reduce the environmental footprint, in addition to HSE risk” commented Hans Fjellanger, Business Development Director at IKM Subsea.

MAC to provide marine assurance services

Maritime Assurance & Consulting (MAC), a Bureau Veritas company, has been awarded a high value contract from Chrysaor for marine assurance services, that also incorporates engineering, DP assurance, marine warranty surveying (MWS), project assurance and compliance services.

Chrysaor is focused on the development and commercialisation of dormant oil and gas discoveries and incremental reserves. The exploration and production company acquired stakes in 10 North Sea fields from Shell last year and was recently awarded additional acreage in the UK’s 30th licensing round.

Under the contract, that is for 1 year with the provision of two further 1 year options, Aberdeen-based MAC will provide marine assurance services, combining the expertise of its master mariners and marine engineers, to offer operations-based services relating to marine compliance and safety. As well as providing the client with traditional marine assurance services, MAC will also work closely with Chrysaor to develop a range of assurance tools, including guidance on reactivated vessels from cold stacking.
Field Joint Coating and Custom Coating Services

Pipeline Induction Heat (PIH) provide specialist field joint coating services at spool base locations, offshore pipe lay barges and onshore pipeline construction projects around the world, involving the use of state-of-the-art equipment and processes for the application of a wide range of field joint coating materials.

PIH also provide Custom Coating services for the application of the latest Thermal Insulation solutions (IMPP and IMPU) to bends and spools.
PERMIAN BASIN: PRODUCED WATER CHALLENGES

Ryan Duman, Wood Mackenzie, USA, reviews the risks posed by produced water in the Permian Basin.
The Permian is comfortably positioned as the most important oil supply growth region today. As operators continue to add rigs and ramp up completions. Over 2 million bpd of oil supply growth is expected over the next 5 years. While this is attainable, the number of operational risks and bottlenecks continues to grow.

One of the biggest risks facing operators today is the issue of produced water. The growing water situation in the Permian presents a unique set of challenges compared with years prior. The sheer volume of water is unprecedented. Record drilling activity is compounded by more water used in completions and water cuts from the targeted formations rising quickly in older horizontal wells. In some cases, water-to-oil ratios (WOR) in the Delaware Basin can reach as high as 10:1 and operators are simply unable to cheaply reinject all those volumes.

Water handling is expensive and unit costs are also expected to rise as the simple solutions such as local shallow injection become exhausted. Rising volumes and rising costs are a bad combination that pose an impending supply risk to the overall region.

In a recent analysis, Wood Mackenzie modelled numerous scenarios of rising water cuts and growing water management costs and found Midland and Delaware basin sub-play economics could be impaired by US$3 - 6/bbl. These higher breakevens could result in a nearly 400 000 bpd reduction to the integrated Permian oil supply forecast by 2025. The bulk of the reduction would come from the Delaware Basin.

Permian water challenges
Operators have had to creatively manage produced water in the Permian for decades. The challenge now is that unconventional operations pose a series of different considerations from conventional fields.

One of the most considerable challenges is that most produced water cannot be reinjected into tight formations for water floods or enhanced oil recovery (EOR), whereas, in conventional fields, they could. Although, some Wolfcamp and Bone Spring operators are testing the potential of enhanced recovery techniques, there are no large-scale applications in place. As a result, produced water must be injected into separate saltwater disposal (SWD) wells, recycled or reused.

This challenge is amplified over time as produced water volumes increase throughout the life of the well. Geographies and geologies of the well also have an impact. Delaware Basin WORs are often twice as high as in the Midland Basin. Greater formation depth and fractures hitting faults can cause WORs to increase dramatically as well. For the Wolfcamp formation in the
Delaware, the water cut (produced water/oil + produced water) has increased from an already high base of approximately 70 - 80% in the first four years of production.

Water demand will continue to increase as operators strive to improve completion efficacy. Volumes pumped per completion are 50% higher than in 2015, close to 17 million gal. water per current well in the Midland Wolfcamp. This also results in growing volumes flowing back to the surface, because the formation has relatively high water saturation and does not hold fracture fluids.

Multi-well pad development results in a higher concentration of produced water in a single geography. This puts greater strain on nearby SWD wells and can cause sections of disposal formations to pressure up too fast, limiting the injection rate and causing casing issues in proximal areas of the play.

Modelling the problem
Scenario analysis is required to fully appreciate the risk of rising water volumes. Solutions that work today will not be enough to manage future volumes. Costs will escalate to varying degrees as producers compete for the cheapest solutions.

As a simple illustration, if Permian oil production approaches 6 million bpd by 2025, the average water cut in the region is 4:1, and it is assumed that the total water management costs are US$2/bbl. As a result, the annual water-related expenditure in the region could reach US$17 billion, or nearly 20% of total drilling expenditure this year.

The sample set of wells with production histories long enough to see the acute details of how water cuts evolve is limited. Also, state reporting does not include robust datasets for water. As such, Wood Mackenzie built scenarios to quantify the future risk producers face.

In their analysis, using water saturation data from subsurface partner NUTECH, the company derived multiple water production curves for each sub-play in each basin. Each basin has clear areas of higher and lower saturation, so the company applied either a 'wet' or a 'dry' water production curve to that Wolfcamp or Bone Spring sub-play to add more granularity to models and represent the inevitable variation across acreage.

The company also analysed the costs associated with water handling, which currently range between US$0.50 - 3/bbl. These costs include sourcing, transport, disposal and recycling.
Trucking availability and the proximity of a well or pad to existing SWD wells can be the biggest influencing factors.

Producers are working hard to keep costs in the lower end of that range. However, early indications from increasing portions of capital budgets being spent on water solutions could be the canary in the coal mine. For example, Pioneer Natural Resources is allocating US$300 million in 2018 for tank batteries and SWD facilities, in addition to new facilities and other expansions for below-grade cellars. Current SWDs cannot handle all the future produced volumes and recycling is not a panacea. The produced volumes are simply too great for all the barrels to be reused in subsequent completions.

Modelling all these variables found that under all the elevated future cost scenarios, no sub-play type wells became uneconomic. Higher water volumes and higher costs did not shorten the economic life of these wells either. However, the investigation of single well water risks quickly scales up to a material impact when the combined impact of rising water volumes and increasing water costs on future breakevens for undrilled wells deep into companies’ inventories is studied.

These metrics increased on average by US$6/bbl in the aggressive cost scenario compared with the base case that utilises water cuts seen today, as well as current lease operating expenses (LOE) to handle produced water. To put that magnitude of increase into perspective, 25% lower productivity or a 20% increase in development and completion costs is needed to realise a similar increase in breakevens. The managed cost scenario resulted in a breakeven change about half as large, and variations were clearly seen at the sub-play level.

**Combating the challenge**

Early water planning was difficult because the location of the most densely developed Permian acreage was not completely known. Now that it is, some operators – likely the later entrants with more remote acreage – will need to play catch-up in order to appropriately manage water-related risk.

One of the best opportunities for operators to reduce water costs is by investing in pipeline infrastructure, limiting the amount of trucking and collaborating with offset operators. Relying heavily on trucking can result in an incremental US$1 - 1.25/bbl with virtually certain future price increases as trucking regulations become stricter, pads become more remote, and roads become more congested.

Although water recycling cannot solve all the problems, it can provide massive support over the next few years. Operators such as Callon Petroleum have recently mentioned sourcing 50% of water volumes from recycling for certain Delaware Basin drilling pads with no impairment to well productivity. The industry can expect to see the proportion of recycled water volumes continue to increase as more operators understand how to best manage chemistry and use the volumes in new, offset completions.

There are also increasing questions regarding whether water could ultimately become a revenue source for operators. Produced waters are expected to far exceed the demand for hydraulic fracturing so opportunities may exist for the sale of recycled water to agriculture for example.

Managing this risk will require large amounts of capital, particularly in regard to water disposal. Expect producers to invest more in water management solutions, and if budgets stay relatively flat the next few years, watch drilling capital be diverted to water-related investments. Just as the level of drilling intensity in the Permian breaks basin records, so should the scale of water management solutions.
Fracturing sand (i.e., frac sand or proppant) is a key component used in hydraulic fracturing operations that facilitates production by keeping fractures open so that oil and/or natural gas can flow freely from the formation into the casing and up to the surface.

Over the past decade, the explosion of unconventional resource development in the US, coupled with the implementation of larger pads and longer multi-laterals, has resulted in a significant increase in the demand for fracturing sand nationwide. In 2017, for instance, the Permian Basin saw a two-fold increase in sand usage compared to 2016 and it is predicted that figure will double again through 2018.1 Similarly, in the mid-continental region, the average amount of sand being used per well has increased by nearly 30% over the past year.

As is the case with any commodity, growth in demand for frac sand over the past decade has been accompanied by a corresponding increase in price. In fact, just prior to the industry-wide downturn, it was not uncommon for proppant to represent more than 20% of drilling costs. With crude prices at more than US$100/bbl, this was palatable. However, as oil prices declined, producers in West Texas could no longer justify the expense of hauling in sand from places like Wisconsin, Minnesota, and Illinois and they began taking a hard look at how they could improve processes to become more efficient.

This resulted in a wave of investments aimed at moving sand processing infrastructure closer to shale plays, which drove down costs by effectively eliminating long-haul transport from the equation. And while it has been successful in helping Permian producers remain profitable amid the low price environment, it has also introduced new challenges that necessitate advanced measurement solutions and digital oilfield capabilities.

Pushing the envelope for efficiency
The feasibility of utilising native Texas sand for fracking instead of costly white sands from mid-western states, coupled with the reduction of transport costs and improved fracturing technologies is bringing stability to the US oil industry. However, the need to improve efficiencies and drive out costs has not diminished.

The situation in the Permian Basin, as it pertains to frac sand level inventory monitoring, is similar to what was seen in the Bakken with crude oil level inventory monitoring five years ago. Leading up to the downturn, when prices exceeded US$100/bbl, many operators in the Bakken were so busy producing that monitoring the level and interface of oil and water in produced water tanks was not immediately addressed. It was not until production began to slow down that accountability for residual crude oil in water disposal tanks became more relevant and interface and level measurement technologies were implemented.
Unlike the Bakken, crude oil production in the Permian Basin does not have the luxury of high prices and the window for profits is narrower. While Permian producers have achieved improvements and driven out costs in a number of different production areas, independent producers will continue to push the envelope for efficiency. As a result, room for waste is not an option and the need for accurate and transparent inventory monitoring of frac sand is of the utmost importance.

**Process measurement – a key element in the digital oilfield**

In recent years, an increasing number of sand processing and proppant plants have embraced level measurement and weighing solutions as part of their processes to ensure reliable inventory levels. Many, however, have taken it a step further by leveraging the data these solutions provide to drive operational efficiency.

In the oil and gas industry, as shale producers have sought new ways to improve production, well site data has become more valuable. While digital oilfield solutions based on the cloud and Internet of Things (IoT) have proven to be powerful tools, they can only be leveraged if instrumentation is in place to monitor process variables, such as pressure, temperature, flow, etc. In frac sand processing, without accurate data on the level of proppants that are stored, delivered and trans-loaded, a significant piece of the puzzle is missing.

Combining advanced level measurement with digital oilfield solutions provides transparency into well site operations. With continuous input from sensing devices, data from the field, such as sand frac levels in silos, can be closely monitored and analysed so that the health and effectiveness of processing and storage operations can be continuously improved.

**Radar level transmitters for frac sand inventory monitoring**

Interestingly enough, some operators still require convincing that reliable level measurement can be achieved in dusty environments with radar level transmitters. Much of this is due to the fact that prior to the advent of high frequency transmitting solutions and advanced signal processing algorithms, the only way to ensure the accuracy of mainstream (low frequency) through-air measurement technologies when measuring levels of silica sand, sugar or similar solids was through a highly arduous and painstaking installation and setup process.

When using low frequency transmitters, the spherical shape and steep angle of repose of silica sand tends to reflect the emitted signal, yielding a false reading. In 2011, Siemens addressed this challenge by introducing the SITRANS LR560, which is a two-wire, 78 GHz frequency modulated, continuous-wave radar (FMCW).

The high frequency enables the LR560 to emit a very short 4 mm wavelength, which provides enhanced signal reflection, even from solids with a steep angle of repose. Its unique lens-styled antenna has a 4˚ beam angle and a sensing range of up to 328 ft. This, coupled with the advanced signal processing capabilities of the transmitter, enabled clients in a wide range of industries to solve the problem of signal-skipping – the same problem that many operators are experiencing in their frac sand silos. Overall, the transmitter provides consistent and reliable level measurements, regardless of how much dust is in the air. It is also a plug-and-work solution that can be installed and brought into operation in a matter of minutes.

**Reduced costs, improved safety, ensured compliance**

Installation of a radar level transmitter for monitoring levels in frac sand silos provides a number of benefits with regards to safety, cost, and compliance.
Announcing a seismic change.

FairfieldNodal is now, officially, Fairfield Geotechnologies. It’s a new brand with nimble new strategies for meeting the needs of a changing industry.
OSHA recently ruled on new limits regarding worker exposure to crystalline silica dust. As enforcement of these new regulations increases, users of frac sand will have to implement measures that minimise their workers’ exposure to environments where silica dust is present. Installation of a radar level transmitter satisfies this requirement, as it removes the need for personnel to climb silos and open hatches to verify inventory levels. It also fulfills overfill prevention requirements, which is an area that will be closely regulated in order to prevent silica dust dispersion during filling and emptying of storage or holding silos.

When examining the benefits of reliable level measurement, one cannot discount the cost associated with improperly managed or incorrect readings of proppant inventory levels. This can come in many forms, including idling trucks, inefficient use of time, and in severe cases, lost production. The cost of instrumentation becomes miniscule when compared to the financial losses incurred when production falls behind. Considering this risk and the vast amount of proppant being used in hydraulic fracturing today, the lack of reliable level measurement solutions is a major inefficiency – especially for an industry that has managed to redefine success amid pressure from sustained low prices.

Overall, instrumentation solutions represent a minute fraction of the overall price tag to develop a sand processing plant. However, the impact they can have on production and efficiency is evident both during the plant development process and after it is in operation. For example, Siemens was recently performing work at a sand frac processing plant where radar transmitters were installed in narrow ports and protruded inside the silos. In this particular case, the pipes were too long and prevented the transmitters from being properly aimed to achieve consistent level measurement. This hindered the plant from obtaining reliable level measurements of frac sand for the entire range of the silo and will lead to future expenses to correct the situation.

It is situations like this that highlight the importance of engaging early with a solutions provider during the design phase to decide what instruments should be utilised for inventory level monitoring. Optimal performance does not take place in a vacuum. There are many parts at play in any operation, and given the current economic environment, there is no margin to ignore what may ostensibly seem like a small detail.

**The importance of accurate weighing**

As previously mentioned, longer laterals and larger well pads require more sand and thus, more storage capacity. This inevitably increases trans-loading activity. Depending on the trans-loading system and area of distribution, accountability for what is being paid for and utilised – especially for high-end proppants – must be reconciled. The system’s function, therefore, is not solely to convey sand or proppants from point A to point B, but also to validate asset management along key points in the process. Implementation of reliable and accurate belt scales play a key role in achieving this.

Utilisation of native Texas sands does not completely eliminate the need for more expensive white sands. Thus, accurately weighing how much proppant is being delivered by a rail cart is paramount. A single belt scale from Siemens can achieve +/- 0.5% accuracy. Doubling the number of belt scales further improves accuracy to +/- 0.25% and this can be readily verified via onsite material tests. Ultimately, the stage and price of the proppant being used will dictate the level of accuracy required by the belt scale.

One aspect of the company’s belt scales that makes them particularly attractive for use in sand frac processing plants located in remote areas is that they are simple to install and require minimal maintenance. Furthermore, they are the same type of scales used with a National Type Evaluation Program (NTEP) certified custody transfer package. The latter should be considered with transactions involving more costly proppants. Additionally, the scales can be configured so that real time or totalised tonnage data is fed into the digital oilfield acquisition system for analysis and optimisation.

**Leveraging instrumentation to drive safety and efficiency**

Although silica dust remains a concern for shale producers, there are effective measures that can be put in place to minimise exposure by enclosing open areas where it is present and breathable. This includes using proppant coating technology as a dust suppressor and adding skirts to enclose conveying systems. While the primary purpose of level measurement instrumentation is to maintain dependable inventory levels, it is yet another means to mitigate dust levels and help producers remain compliant with current OSHA guidelines.

Automation solutions like radar level transmitters and belt scales can also generate significant economic value – particularly when one compares their relatively low cost with the significant financial losses that can occur as a result of inaccurate or improperly managed frac sand inventory levels. In the coming years, it will be solutions like these, which are inclusive of both the digital oilfield and essential well site processes, that help operators drive further efficiency and remain competitive in the ‘lower for longer’ environment.

**Reference**

With the MAXIMUS MMX cameras, a new world of cost-effective video surveillance solutions for onshore, offshore, marine, heavy industrial or hazardous environments.
Exploration for hydrocarbons is a continuous challenge, full of complex obstacles that are technical, as well as market-driven. Still, the oil and gas industry remains an indispensable player in providing means for modern living. Because the industry is driven by innovation, the relevance of its impact will not wane with changing technology or regulatory burdens, as the world will always need access to sustainable energy.

Industry challenges
Naturally, in a down market, the great expense surrounding hydrocarbon exploration and production is considered to be a high-risk investment. The costly overhead of drilling has caused a number of operators to scale back or close down operations. Predicting when the market will rebound is an educated guess at best, so companies that continue to frac have been forced to operate as if a new normal is in place, altering business overheads to make sure that well costs do not make drilling unsustainable.

Accordingly, the prolonged low-price environment for oil and gas has shifted operators to focus on employing cost-saving methods anywhere practical throughout the drilling and completion process in shale plays. The recent market downturn has forced operators to place a greater emphasis upon efficiency across the board in drilling and completion operations, and in some instances, to re-evaluate presumed best practices in favour of more innovative technologies and techniques.

Meeting the challenge
In recent years, the oil and gas industry has focused on the development of game-changing solutions for retrieving oil reserves – especially in shale plays where horizontal drilling and hydraulic fracturing have been employed. The result has been a monumental increase in producible reserves across the globe, and has fundamentally altered the way operators pursue exploration and production.

Oil companies of all sizes have harnessed new technologies to locate and extract quantities of oil and gas that have proven substantial enough to dissipate some past concerns about dwindling reserves. Similarly, shale plays have proven to be the primary factor in the optimistic outlook for the future of the industry.

Limited entry completions
For decades, the generally accepted method for horizontal multistage fracturing in tight rock formations has been the plug-and-perf type completion (PnP). This is a limited entry system, which utilizes a series of plugs to separate each stage of the fracturing process, allowing for precise control of the fracture geometry.

However, this method has been criticized for its inefficiency and environmental impact. As a result, researchers and engineers have been working to develop alternative methods that offer greater control over the fracturing process and minimize waste.

One such method is the single-point entry completion, which involves creating a single entry point into the formation and then fracturing multiple stages simultaneously. This approach allows for greater control over the fracture geometry and can reduce the amount of waste generated.

Rair Barraez, Stage Completions, USA, discusses the advantages of single-point entry completions.

SEEKING A SINGULAR FUTURE
of spaced perforation clusters along each section of the lateral wellbore, referred to as a stage. All clusters within each stage are stimulated simultaneously during a single pumping treatment.

The basic assumption has been that all clusters receive equal stimulation regardless of formation characteristics. Inconsistencies in production results and post-stimulation fracture analysis have led to the conclusion that formation factors play a large part in the overall efficiency of PnP completions.

Formation heterogeneity can result in natural stress fractures and variable in situ fracture gradients along the lateral section. This can cause stimulation treatments to concentrate at perforation clusters near natural fractures, or at clusters near the lowest formation fracture gradients rather than achieving equal distribution. Consequently, some clusters can be overstimulated while others may be pinched off and receive little or no treatment within a single stage.

**Single-point entry completions**

Recognition of this phenomenon over more recent years, has prompted the development and introduction of various alternative completion technologies, some of which accommodate single-point entry fracturing. This type of completion commonly utilises a coiled tubing activated sleeve or a ball drop system. The sleeve is integral to the casing string or liner and is prepositioned at the desired fracture location within each stage to be pumped. The sleeve is opened via mechanical and/or hydraulic means prior to pumping, and the fracture position is controlled, since treatment enters the formation only through ports in the sleeve. This prevents variable formation characteristics from affecting the desired fracture placement.

In the past, however, operators who implemented single-point entry type completions on a trial basis were faced with mechanical limitations that prevented adoption as a standard for all applications. Potential drawbacks included the risk of not getting to target depth with coiled tubing in extended reach laterals due to metal-to-metal friction generated with the casing wall. Additionally, ball drop systems typically have a finite number of graduated seats, which could limit the number of stages available within a wellbore, and most ball drop systems leave seats in the hole, which have inside diameters smaller than full wellbore.

While these historical limitations forced some operators to return to the PnP completion the industry is so familiar with, they also put the spotlight on the industry’s need for disruptive technologies to address the concerns. With the right solution, operators could see incredible benefits, from reducing the horsepower required to pump the treatment and the ability to better maintain real time control during pumping operations, to more accurate treatment modelling and improved production results.

**Fracture efficiency analysis and production comparison**

Various methods have been utilised to analyse post-stimulation results in low permeability horizontal wells. Temperature and acoustic gauges are typical, and in a few cases, fibre optic gauges have been installed with the casing string. Microseismic and radioactive tracer analyses have also been performed. Among the various methods, one study of numerous horizontal well production logs concluded that almost 30% of perforation clusters do not contribute to production in PnP wells, while another used radioactive tracer data to uncover similar findings.

Countless studies and use case examples have uncovered the impact of SPE fracturing on both efficiency and production. In a June 2014 public presentation, Whiting Petroleum Corporation cited an example where they completed one well at Missouri Breaks with a cased hole single-point entry system. Initial production was 40% higher than two offset wells with similar laterals completed with the PnP method and 70% higher than one offset well completed in open hole with a sliding sleeve.

Newfield Exploration Company co-authored a technical paper in 2013 in which two identical wells were drilled consecutively in the Granite Wash gas play in the Texas Panhandle for the purpose of providing controlled comparison data between a PnP completion and a single-point entry completion. The single-point entry gas well exhibited a production rate approximately 100% higher than the PnP well after 75 days online. An estimated ultimate recovery (EUR) model was simulated in which the single-point entry well was estimated to exceed the PnP well by 107% (6493 million ft³ equivalent versus 3143 million ft³ equivalent).

Similarly, Arrington Oil & Gas Operating LLC co-authored a technical paper in 2014 which documented a single-point entry completion in the Bone Springs reservoir in West Texas. The casing was stuck off bottom so the well was completed with a 2600 ft lateral rather than the intended 4800 ft length. The average daily production exceeded three PnP wells on the same lease by more than 100% after 8 months, even though those wells had 4800 ft laterals. The production of the single-point entry well also exceeded production on four PnP wells with 4800 ft laterals on adjacent acreage by 50% to 100% after 4 months.

**Recognising the advantages**

The data is clear: single-point entry completion technology offers decisive technical advantages for drilling operators eyeing the future.
INTRODUCING A NEW SPECIES.
No other technology on the horizon is geared toward planning and optimising wells with the kind of control and predictability single-point entry practices offer in terms of efficiency.

The implementation of Stage Completions’ Bowhead II system, a single system that meets the design-change demand limitations of traditional single-point entry fracturing systems, has resulted in potential cost reductions for fracturing operations. Operators have also experienced better real time control during pumping operations, and more accurate treatment modelling has translated into improved production results across the board.

For example, an operator in the Eagle Ford Basin completed an extended reach well with 116 Bowhead II collet activated cementable sliding sleeves. During the deployment and installation of the 15 000 psi system, the operator was able to gain efficiencies by pre-bucking the Bowhead II valves to the casing joints allowing for a safer handling of equipment on the rig floor, a reduced installation time, and tighter fracture stage spacing due to the shorter overall length of the Stage Completions’ hardware.

During the fracturing operation, 117 intervals were stimulated with the Bowhead Technology in a record time of 160 hrs and accurately placed 11.6 million lb of sand and 361 000 bbls of fluid at a maximum sand concentration of 4.7 ppg and 42 bbls/min average rate. The success of the operation is a result of the simplicity of the technology, running a dissolvable ball on a collet that activates the sliding sleeves and eliminates the need of employing coiled tubing or wireline. The Bowhead series has a constant ID throughout the wellbore that allows for higher pump rates and higher sand concentration. Elimination of coiled tubing and ball seats led to reduced friction during the fracturing treatment, decreasing the required horsepower for the operation by up to 60% of the total pumping units available on location and optimising every stage, while maximising the stimulated reservoir volume. The collet launcher (Figure 2) employed during the stimulation is designed to enable continuous pumping operation and is remotely operated, keeping all field personnel out of the red zone.

An advanced acoustic and pressure monitoring system was installed on the wellhead. The high sensitivity and accuracy of this technology confirmed the launch and consistent sleeve engagement of the collet in every single stage (Figure 3), adding validation to the shifting signature observed on the surface treating pressure (Figure 5), also corroborated by the actual displacement volumes in each case.

The green curve in Figure 4 represents the pressure increases as the collet is travelling through each installed sleeve until landing at the target depth. This unique feature provided the operator with the ability to monitor and locate the collet in the wellbore throughout the launching and shifting process.

Figure 5 shows the treatment plot for stage 20. The shifting signature is observed on the surface treating pressure curve at 14:10 after decreasing the pump rate to achieve the recommended landing velocity, followed by the immediate fracture treatment as designed for the stage.

The focus turns to completions

To date, the industry has been resilient in responding to new technical challenges. Engineering a way past this latest set of market-driven obstacles will have very tangible applications for how the industry as a whole tackles shale plays.

As the global demand for fracturing continues to climb, operators will have to innovate to meet new challenges – both in the field and to the bottom line – as they emerge.

References
The new era of microseismic monitoring is quickly approaching a quarter century of deployment and utilisation. From the ground-breaking Cotton Valley Consortia project in 1997, literally thousands of treatments have been monitored using microseismicity throughout North American unconventional plays. The vast majority of the monitoring programmes have consisted of singular arrays of downhole sensors providing estimates of event locations and their relative magnitude or strength. These programmes have been used to provide an understanding of reservoir containment and the role of faults in potentially diverting oil and gas from the reservoir. For the most part, analysis and interpretation has involved examining the distribution of seismicity and extracting relative dimensions, length width and height, and overall frac orientation as a proxy for the stimulated reservoir volume (SRV), which plays a critical role in defining the acreage of unconventional plays. Given the economic importance of the SRV, accurately quantifying the SRV is critical in gauging the success of well completion strategies. In terms of microseismicity, it is widely accepted that the overall distribution is an over-estimation of the actual SRV. As a result many operators question the value microseismic monitoring brings in assessing production capabilities and as an approach to optimise stimulations and reduce operational costs.

Approaching microseismic data analysis
Recently, it has been proposed that the characteristics of individual microseismic events can be used to identify a collective behaviour associated with different reservoir responses as related to the rock properties (e.g. clay content, fracture and stress states). The premise is that microseismicity occurrences are associated with an underlying dynamic stress field and that events exhibiting similar characteristics (e.g. energy and stress release) provide an opportunity to define the behaviour of the

Ted Urbancic, Gisela Viegas and Doug Angus, ESG Solutions, J.M. Thompson and D. Anderson, Anderson Thompson Reservoir Strategies, explore whether characterising stimulation effectiveness can be achieved through microseismic monitoring.

Making Moves with Microseismic Monitoring
Ted Urbancic, Gisela Viegas and Doug Angus, ESG Solutions, J.M. Thompson and D. Anderson, Anderson Thompson Reservoir Strategies, explore whether characterising stimulation effectiveness can be achieved through microseismic monitoring.
reservoir volume encompassing those events (Figure 1). In this context, events are generated in a stress field where the most rapid changes in stress occur. Based on this concept the reservoir can be described in a manner as to outline differences in terms of deformability (plasticity index), the stress state (stress index), and the ability to transfer load or stress from one region of the reservoir to another (diffusion index). These parameters, collectively referred to as Dynamic Parameters (or DPA for Dynamic Parameter Analysis) uniquely describe each reservoir volume as a whole without considering the degree of importance of each calculated parameter. However, by considering the inter-relationship between these descriptive states on a ternary diagram the importance of rock properties and fracture state on deformability can be identified versus the role of the dynamic local stress state that is continually being affected by the stimulation of the well (Figure 2). Reservoir volumes exhibiting a decrease in effective stress, complex fracture network activation, events occurring close together at short time intervals, and low radiated energy can be considered to exhibit the properties as related to fluid driven failures. Alternatively, if the reservoir exhibits an increase in deviatoric stress, with activation on optimally oriented fractures, more diffusive event distributions, and high radiated energy, than failures can be considered as being stress driven. As a result, spatially, the reservoir response surrounding a point of injection can potentially be tracked and used to define the likely volume capable of sustaining flow and production. By considering time intervals related to the injection parameters (proppants, rate or pressure changes, inclusion of diverters), the influence of development of a connected fracture network capable of flow can also be assessed.

**Example applications**

These approaches have been employed in the major unconventional plays within North America. Based on these observations operators have been able to assess the effectiveness of their completion programmes and isolate factors which may influence their success at generating a SRV that optimises well and stage spacing. In Figures 3 and 4, examples have been provided from a single phase gas rich formation. Understanding the ability of the injection programme to generate a discrete fracture network capable of flow is shown in Figure 3. The event distributions are both colour coded by proppant concentration as well as by symbol for the Pad, 50/140 prop, 40/70 prop, and a power prop injection phases for a single stage. The observed distribution in seismicity is extensive, with overall frac growth in a northeast-southwest orientation, in-line with the regional maximum horizontal stress. Based on event distribution it would suggest that nearby wells are connected and that the overall frac length capable of production is on the order to 500 - 600 m (~1650 - 1950 ft). An image of the plasticity index or PI at treatment well depth has also been provided. It is clear that the areas of highest deformation occur in small region adjacent to the perforation zone, is limited in extent and dimension, and represents a significantly smaller producing region for the stimulation, on the order of 25 - 30% of that would be pre-supposed based on event distribution alone. The higher deformation also can be considered to be asymmetric about the treatment well, with growth to the northeast in the direction of previously stimulated rock. The ternary diagram is revealing. Instead of showing the event distribution, the symbols represent distinct event groupings or clusters associated with differences in reservoir behaviour as previously discussed. The Pad phase exhibits higher PI values and lower SI values than all the subsequent phases. The suggestion would be that the Pad phase results in an interconnected fracture network extending outwards from the treatment well. The region coincides with the spatial distribution of higher deformation (red-yellow) and it can be suggested has the potential for production. The introduction of smaller proppant results

![Figure 1](https://example.com/figure1.png)

**Figure 1.** (Top) The collective behaviour of microseismicity described schematically, where common characteristics for events with ‘like’ behaviour are grouped spatially or spatio-temporally to define reservoir volumes or groupings with similar responses as shown by the distribution of ellipses in plain view. (Bottom) Three parameters are used to describe the rock behaviour and their ‘end members’ are identified in the lower schematics.

![Figure 2](https://example.com/figure2.png)

**Figure 2.** The reservoir volume behaviour parameters can be represented on ternary diagrams and their interplay can be used to identify primary and secondary production volumes as related to fluid enhanced permeability rather than stress related failures away from the perforation zone.
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in a change in fracture behaviour, with stress beginning to play a slightly more important role than during the Pad phase (increase in SI values). It is apparent with the introduction of larger proppant that the influence of stress is more important, as fractures are related to an increasingly stress driven process (increase in SI values and a decrease in PI values); this results in fractures that unlikely will contribute to production. The power prop, a smooth resin coated ceramic proppant, has the effect of moving the fracturing from a stress driven to a higher influenced fluid driven process. Based on these observations it can be suggested that operators have the opportunity to track these changes in near real time and make decisions in the field to control the overall frac growth and to maximise SRV while controlling costs.

One of the inferences of the example provided is that the regions of highest deformation corresponds to the SRV leading to production. By combining DPA data with rate transient analysis (RTA), one can define the geometric distribution of rock volumes that have the highest potential for contributing to near term production. Urbancic et al. showed that by integrating DPA with RTA a definitive SRV could be established and thereby increase confidence in the volumetric extent of production. As shown in Figure 4, a simple model of enhanced flow region (EFR) can be established on a well by well basis. For the example provided, a model history match constrained to matrix permeability in the 10 - 100 nanodarcy range, based on core/DFIT data in the region, with fracture height constrained to total net pay thickness, EFR width set to the maximum possible (inter-stage spacing), and total drainage volume limited by lateral no-flow boundaries constraint, the frac half-length would be \( x_f = 89 \) ft (27.1 m), suggesting that a well spacing of 660 ft (~200 m) will result in product left behind. In other words the well spacing is too large. Using the produced volume as a constraint, the DPA distribution along the well results in an average per stage frac half-length of 272 ft (82.9 m) and a frac height that is less that net pay height. Utilising these constraints RTA refines and increases the confidence in the SRV as shown with the history matched data. More rigorous production modelling can be performed to explicitly account for the inhomogeneous distribution in DPA values along the well, as shown in the production simulation model (Figure 4) which illustrates the quality of history match between predicted and actual gas, condensate, water and bottomhole flowing pressure. This workflow provides a forward projection of increased gas production over what is predicted from RTA alone.

**Looking ahead**

As these analyses suggest, a paradigm shift in thinking is required when examining microseismicity. Rather than considering individual events or overall distributions of events to make decisions, by looking at the collective behaviour of microseismicity, the effectiveness of stimulation treatments can be redefined and a sense of the SRV leading to production can be obtained. By approaching microseismicity in this manner, it is likely that stimulations can be assessed in a near real time sense to improve stimulation programmes and that the calculated SRVs can be used to assess well and stage design scenarios with the goal of attaining better reserve estimates.

**References**

The ‘shale revolution’ rapidly transformed the exploration and production industry in North America. In a short time, horizontal well completions became the primary use for coiled tubing. The new demands severely challenged coiled tubing, and failures rose steeply. In response, Tenaris developed BlueCoil® technology, with the potential to increase tubing life by up to four times. Introduced in early 2016, during the depths of the global oil price crisis, the technology quickly proved its value. Since then, it has been widely employed across shale well completions.

History
In 2014, the coiled tubing industry within North America had undergone an important transformation, which had begun around 2006 when coiled tubing was first used to complete horizontal shale wells. With the initial success in the Barnett shale, horizontal shale well development quickly spread to other basins and soon dominated North American exploration and production. The growth of shale drilling is well illustrated by looking at the percentage of rigs in the United States engaged in horizontal drilling (Figure 1). From 1991 through to 2006 that number changed little and then increased from approximately 8% to nearly 90% today. In absolute terms, horizontal drilling increased from about 250 rigs in the spring of 2006 to a peak of over 1300 in the autumn of 2014. The main application for coiled tubing shifted away from traditional well intervention towards shale well completion in North America by 2011.

With the plug-and-perf process established, the focus after 2011 turned to well completion optimisation. Laterals became longer,
fracturing stages and proppant quantities multiplied, and coiled tubing activity continued to grow rapidly. From 2006 until 2014, the global coiled tubing unit count, excluding the US, grew 38% while the US count increased by 107%.

Relative to traditional intervention work, shale well completion operations demand higher strength coiled tubing, larger tube diameters and higher pumping pressures. These operating conditions created stress and strain levels in the tubing that are approximately double those experienced in intervention work. The severe operating conditions pinpointed weaknesses in the coiled tubing, and particularly the bias weld, which joins steel strips prior to milling. The frequency of coiled tubing field failures skyrocketed, as shown in Figure 2, based on statistics compiled for one coiled tubing service company. To reduce the failures, oil and gas companies placed limits on coiled tubing utilisation, either in the form of de-rating factors, maximum tubing fatigue life, or maximum running footage. It was an expensive way of dealing with the problem.

Clearly, better coiled tubing was needed, capable of meeting the new demands. This required the development of a full metallurgical understanding of the current manufacturing process in order to identify improvements. Armed with this knowledge, Tenaris created a new technology, including new steel chemistries and a new continuous heat-treatment process that produces a full microstructural transformation along the entire length of the coiled tubing. The result is a coiled tubing string with a uniform, homogenous and improved microstructure along its entire length, which increases the low-cycle fatigue resistance of the tubing and removes the need to derate the bias weld.

Current climate
Since 2014, the coiled tubing industry has been swept along in another, and much broader transformation, caused by a global drop in oil prices. Oil prices began to decline in the autumn of 2014 and then the price decline accelerated when the OPEC ministers announced at their November 2014 meeting that they would not reduce production in response. Figure 3 shows the WTI oil price and the response in North American drilling activity. The impact of the price decline was profound, causing a peak-to-trough decline of over 80% in drilling activity in less than two years. It was within this crisis that Tenaris, in early 2016, began production of BlueCoil strings.

One measure of coiled tubing activity is the number of active coiled tubing units operated by service companies. The total number of active coiled tubing units in North America in 2014 and today is relatively unchanged. This fact seems paradoxical, given the precipitous drop in the drilling rig count, and coiled tubing’s new dependence on drilling activity. However, the change within service companies during the same period tells a much different story. Although, the major international service companies have reduced their coiled tubing units in North America by as much as 70%, another group of new, smaller companies has grown aggressively during the same period, despite the decline in oil price and rig count. Selecting a group of ten companies that are representative of the small aggressive growers, their coiled tubing unit fleets are comprised of about 79% large coiled tubing units compared to all other companies whose fleets contain 53% large units. It is unlikely that many of the smaller coiled tubing units idled after the 2014 downturn will return to service.

Another change from 2014 to today is the shift away from smaller coiled tubing units (2 in. OD tubing and smaller) and towards larger units, using 2 ¼ in. and 2 ½ in. diameter coiled tubing, which are better suited to shale well completions. This is especially true for the same ten growth-oriented companies described above, whose coiled tubing unit fleets are comprised of about 79% large coiled tubing units compared to all other companies whose fleets contain 53% large units. It is unlikely that many of the smaller coiled tubing units idled after the 2014 downturn will return to service.

The production of BlueCoil technology began in early 2016, after designing and constructing a custom-built heat treatment line to manufacture the strings. While the timing of the launch did not appear
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favourable, the global oil price crisis was actually beneficial. High oil prices can impede developments and the drive for efficiencies. The technology had the potential to create value and cost savings; in terms of coiled tubing utilisation and operational efficiencies such as reducing the disruption caused by field failures, reducing non-productive time (NPT) spent changing coiled tubing strings, and many other factors. With oil prices at less than half their 2014 levels, and the resulting squeeze on service company operating margins, the new growth-oriented coiled tubing service companies became early adopters of BlueCoil technology.

In the beginning of BlueCoil string production, claims of improved performance were met with suspicion and scepticism. Oil and gas companies continued to maintain restrictions on the strings usage based on their experience with conventional coiled tubing, such as limits on maximum tubing running footage. It would be necessary to lift these barriers in order to realise the potential of the technology and demonstrate its value. Over time, and based on strong early results and communication with all stakeholders, usage restrictions were incrementally raised, and in some cases eliminated. Service companies began achieving a two-fold increase in average coiled tubing utilisation and string life compared to conventional coiled tubing, leading to meaningful improvements in operating margins. Figure 4 shows the distribution of coiled tubing life, measured in running footage, for over 120 conventional coiled tubing strings, and 139 BlueCoil strings performing similar jobs and in the same geographic region.

In practice
Many strings have performed beyond the average. Table 1 shows the ten most utilised BlueCoil strings, based on running footage, all of which were used in shale well completion operations. This represents a three to four times increase in life compared to conventional coiled tubing.

BlueCoil technology grades have an ‘HT’ designation followed by its specified minimum yield strength in ksi. HT-125 and HT-110 CT strings have been used in field operations for about two years, and HT-95 for about one year. HT-140 is currently undergoing field trials. The company has produced more than 450 strings since early 2016, the majority of them are grade HT-125. The outside diameters have ranged between 1 ½ in. and 2 ½ in., and in wall thicknesses between ¾ in. and ¼ in. The most common string diameter is 2 ¾ in. and the second most common diameter is 2 ½ in. Tapered strings, those that employ continuously varying wall thickness along the string length to achieve performance objectives, such as extended reach in horizontal wells, account for about 80% of the total technology production.

The majority of BlueCoil strings have been used in North America, almost exclusively in shale well completions. A significant number of the heat-treated strings are also deployed in Argentina, in the Neuquén shale development. Smaller numbers are used in Europe, the Caspian region, Asia/Pacific and the Middle East in well intervention operations.

Conclusion
The performance advantages of BlueCoil technology are clear. The more than two-fold increase in average coiled tubing string life and utilisation has created an estimated US$40 million in direct tubing cost savings for service companies. Usage has expanded far beyond the early adopters. Today, there are more than 50 service companies using the technology, including all major international service companies. In just two years, the technology has become the standard tool for shale well completions. While the demanding requirements of shale well completions was the impetus to create BlueCoil technology, the global oil price crisis drove its rapid and widespread acceptance.

The industry was facing an epidemic of coiled tubing field failures resulting in expensive performance de-rating and usage restrictions. The development of an advanced coiled tubing string through a unique manufacturing process utilising new steel grades helped address these issues. It continues to support the ‘shale revolution’ assuring efficient, profitable operations for the coiled tubing industry.

References
3. ‘Intervention and Coiled Tubing Association (ICoTA), Worldwide Coiled Tubing Rig Count.

Figure 4. Distribution of coiled tubing total running footage for conventional and BlueCoil coiled tubing.

Table 1. The ten most used BlueCoil technology coiled tubing strings, based on running footage.

<table>
<thead>
<tr>
<th>Grade</th>
<th>OD (WT)</th>
<th>Length (ft)</th>
<th>Area</th>
<th>Jobs (wells)</th>
<th>Used life</th>
<th>Running ft (million) (one way)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.204 - 0.175)</td>
<td>25 933</td>
<td>West Texas</td>
<td>79</td>
<td>99%</td>
<td>2.2</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.204 - 0.175)</td>
<td>25 368</td>
<td>West Texas</td>
<td>69</td>
<td>89%</td>
<td>1.9</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.204 - 0.175)</td>
<td>24 105</td>
<td>South and West Texas</td>
<td>65</td>
<td>76%</td>
<td>1.9</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.224 - 0.175)</td>
<td>21 000</td>
<td>South Texas</td>
<td>72</td>
<td>92%</td>
<td>1.7</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.204 - 0.175)</td>
<td>23 307</td>
<td>West Texas</td>
<td>74</td>
<td>72%</td>
<td>1.7</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.204 - 0.175)</td>
<td>22 800</td>
<td>Oklahoma</td>
<td>77</td>
<td>45%</td>
<td>1.6</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.204 - 0.156)</td>
<td>22 500</td>
<td>West Texas</td>
<td>50</td>
<td>78%</td>
<td>1.6</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.224 - 0.250 - 0.156)</td>
<td>23 000</td>
<td>West Texas</td>
<td>78</td>
<td>51%</td>
<td>1.5</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.224 - 0.250 - 0.156)</td>
<td>23 300</td>
<td>West Texas</td>
<td>76</td>
<td>48%</td>
<td>1.4</td>
</tr>
<tr>
<td>HT-125</td>
<td>2 3/8 in. (0.204 - 0.175)</td>
<td>22 937</td>
<td>Oklahoma</td>
<td>66</td>
<td>65%</td>
<td>1.4</td>
</tr>
</tbody>
</table>
Traditionally, perforating the lateral wellbore of a shale well can be a bit of a game of chance. By defining perforation stages according to geometric intervals, the perforation clusters can be inefficient, because the rock within a particular stage is likely to be geomechanically heterogeneous. In these cases, inefficient perforation clusters do not propagate sufficient fractures to enable optimal production in the wellbore.

C&J Energy Services’ LateralScience™ method leverages regularly available data collected while drilling to optimise horizontal completions. Because the LateralScience method uses data already on hand, operators can avoid the considerable data-collection expenses normally associated with evaluating horizontal wellbores.

For operators already using other methods to optimise their engineered completions, C&J’s solution is more convenient and economical, affording operators the ability to optimise every horizontal well. Compared to wells completed using geometric completion designs, wells completed based on designs developed using the LateralScience method have demonstrated an average production increase of 30% by optimising perforation clusters and plug placement. Since there is already significant documentation that engineered completions improve production, this article focuses on the additional benefits gained by using the LateralScience engineered-completion process to improve cluster efficiency in order to achieve more predictable stimulation execution.

This information can be used to optimise plug placement, create more consistent stages and selectively target perforation clusters. Selecting like rock for cluster placement improves cluster efficiency, which reduces treatment pressures, minimises the occurrence of screenouts and identifies stages that are likely to be more difficult to treat because heterogeneity cannot be avoided. By improving the fracture execution in these ways, operators can reduce wasted proppant, minimise coiled-tubing cleanout events and improve stage stimulation effectiveness.

Achieving improved fracturing treatments

The primary goal of an optimised completion with respect to cluster and plug placement is to improve the number of ‘effective’ perforation clusters and reduce the occurrence of perforating and fracturing geomechanically heterogeneous stages. In this instance, a cluster’s effectiveness can be determined by the degree that the perforated rock will break down, accept the fracturing treatment and ultimately contribute to the production of the well. To achieve this, each perforated interval would ideally have similar geomechanical properties.

Most operators would define a successful fracturing treatment as one that was executed as designed, without the need to reduce injection rates and with all the planned proppant being optimally placed. Unfortunately, there are numerous parameters an operator needs to estimate, and a poor estimation of these parameters will result in an unsuccessful fracturing treatment.

Two major inputs to the stimulation design are the number and the size of the perforations that can be treated within a stimulation stage. Depending upon whether the well completion designer is...
taking a conservative or an aggressive approach in developing the completion design, the assumed number of effective clusters can range from as low as 50% to as high as 100%. While the details surrounding these design parameters vary by operator and by the reservoir being stimulated, it can be consistently assumed that the outcome of a conservative design would be less effective stimulation of the reservoir and, potentially, lost productivity, where an excessively aggressive design could result in wasted proppant, increased cleanout times and possibly inadequately simulated stages. Ultimately, how successfully an operator predicts and achieves effective clusters will have a direct impact on the economic viability and outcome of the project.

Using the LateralScience method, C&J Energy Services can advise customers on how to optimise cluster and stage placement so that the clusters are placed into rock with similar geomechanical properties. This increases the number of effective clusters significantly and can improve cluster efficiencies by 30 - 60%. C&J’s LateralScience method gives operators confidence when applying a more aggressive fracture design because it increases their ability to successfully pump jobs to completion as designed, without needing to reduce injection rates, and with all the planned proppant being placed. This execution can be achieved at a small fraction of the cost, risk and processing time required to engineer a traditional completion design using data gathered from openhole logging tools.

The Texas POWER play
Tecolote Energy, LLC, a private oil and gas exploration and production company, has used a variety of techniques to economically improve stimulation treatments and increase production in its wells located in the Western Anadarko ‘POWER’ (Panhandle Oil Window Extended-Lateral Resource) play.

Among the steps Tecolote has taken, the first was to apply a complex earth model to target the most prolific horizon within each productive layer of the Pennsylvanian aged reservoirs. Next, the company chose not to follow the commonplace practice of completing wells with external casing packers. Instead, it moved toward fully cemented laterals using plug-and-perf completions. The wealth of historical data from this area has shown that cemented plug-and-perf completions produce far superior performance over uncemented completions. Next, the company increased the number of clusters per stage and decreased cluster spacing, while also pumping 100 to 200% more proppant per frac stage when compared to vintage Granite Wash completions. With each successive change in completion design, Tecolote has seen marked improvement in well production results.

In their continued search for additional techniques to improve completion results, Tecolote’s engineers were introduced to LateralScience methods, which enabled them to improve cluster efficiency and realise further production benefits. The improved cluster efficiency played a role in the success of the Meadows Clifford 31-30 MD EX 2H well, which was hailed at the time as having “the highest 30-day initial production rate from a Tecolote operated well to date.” For the Meadows Clifford 31-30 MD EX 2H well, “production rates on a 24 hr basis peaked 54 days after first sales at 4070 boe/d. The well eclipsed Tecolote’s previous record of 2439 boe/d.” Effectively, this translated to a 67% uplift in production.
Tecolote attributed part of this 67% improvement in the production to the improvements in cluster efficiency, as well as to their ability to achieve more geomechanically homogeneous stages by applying the LateralScience method. Modelling indicated that the original geometric design would have resulted in an estimated 63% cluster efficiency for the entire well, with 22 of the 55 stages being identified as heterogeneous (meaning that 50% or fewer of the clusters in those stages are estimated to be effective). By applying the LateralScience method to optimise cluster placement in the 55 stage design, cluster efficiency improved to 87%, and the number of heterogeneous stages was reduced to seven.

Tecolote used the LateralScience results to take proactive steps to manage the execution and improve the success of stages that were identified as having unavoidable geomechanical heterogeneity or significantly harder rock. The following examples demonstrate the results achieved using the this method in the Meadows Clifford 31-30 MD EX 2H and the Meadows Clifford 31-30 MD EX 1H, both of which were on the same pad.

As shown in Figure 2, Stage 5 demonstrates the type of rock strength variations that can be observed within any given stage. In this case, before beginning the stimulation, Tecolote observed that they were very likely to experience challenges due to heterogeneity. In fact, this stage had the highest breakdown pressure of the well and the highest average MSE values (102.7 ksi) at the perforated intervals.

For the Meadows Clifford 31-30 MD EX 1H, it was not surprising this well also exhibited stages with large variations in rock strength. In stage 10, the highest observed MSE average (73.3 ksi), combined with an estimated 50% cluster efficiency, resulted in the highest observed average treatment and breakdown pressures for that well. Because the MSE results identified difficult stages ahead of time, Tecolote was able to plan accordingly and minimise the effect on stimulation execution.

According to senior asset engineer Clint Shaw, Tecolote sees the LateralScience method as a way of getting consistent production from the entire lateral, rather than having just a few great stages. “We believe that the LateralScience method helps us to fully develop our reserves by creating maximum stimulated rock volume at every perforation cluster. It also limits offset well bashing, which we believe occurs when all of the frac fluid of a given stage goes to one or two dominant clusters,” says Shaw.

By placing their stages and clusters based on geomechanical properties that can be calculated for every well, Tecolote has been able to successfully execute the designed treatment on nearly every stage – and for those stages with unavoidable heterogeneity, they were able to plan the execution proactively to improve success. This enabled them to get better exposure to the reservoir and get consistently stronger-performing wells without increasing operational risk.

**Optimising results**

Unconventional reservoirs provide many challenges because of their heterogeneous nature. Ultimately, once an operator has done the best they can drilling and steering the well to stay within productive zones, there is very little that can be done about reservoir quality. However, using the LateralScience method, the operator can determine whether every barrel of fracturing fluid – and every pound of proppant – brings value.

By improving cluster efficiency, an operator can take a diverse and non-homogeneous fracturing stage and optimise clusters so that they are placed into rock with similar geomechanical properties. In that way, they can reduce the uncertainty related to cluster efficiency and distribute their stimulation as evenly as possible, which ultimately helps to maximise production of the well.

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**SCALEGUARD**

A single application of SCALEGUARD proppant-delivered scale-inhibiting technology has maintained production rates and eliminated costly workovers for nearly two years in previously scale-prone wells in Manitoba, Canada. Similarly impressive results have been achieved in over 200 wells across North America.

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Read on to hear from Apergy Corporation and Nanoramic Laboratories.
Going back to the early 1990s, oil and gas exploration companies were able to improve their operations by including sucker-rod guides in their downhole systems that were constructed of synthetic polyphthalamide, or PPA. PPA was effective in these applications because it has greater resistance than many plastics to a broad range of chemicals, along with high tensile strength and stiffness at high temperatures, better fatigue resistance, increased dimensional stability and high sensitivity to water absorption. That is why PPA became a preferred choice over metal and other plastics, especially in deeper wells that featured operating temperatures reaching up to 300°F (149°C).
However, while PPA could perform reliably at higher temperatures – and is actually rated to 400°F (205°C) – it is not rated for continuous-service at that temperature. This characteristic was discovered after PPA sucker-rod guides were tested using the continuous use temperature (CUT) testing scale, which showed that the service life of continuous-use sucker-rod guides constructed of PPA would begin to be adversely affected in temperatures as low as 220°F (105°C).

The results of the tests indicated that various characteristics of the downhole production environment, such as bottom-hole temperature, chemicals used, side loads, duration of operation, water cut, viscosity of the fluid and well deviation, can reduce the CUT for PPA guides. Additionally, these well characteristics in combination with the varying types and amounts of fines, solids and corrosive elements that are encountered in the production tubing will cause PPA guides to wear faster than in a well with lower temperatures.

In fact, the CUT tests revealed that PPA-based compounds can experience rapid degradation, with greater than 50% loss of strength, after only six weeks of continuous exposure to water at 250°F (121°C) and complete disintegration after one week of continuous exposure to water at 400°F. The combination of chemicals in an aqueous solution at elevated water temperatures causes oxidative degradation of the PPA guide’s molecular structure.

Premature and excessive wearing of sucker-rod guides in high temperatures will pose serious problems in downhole recovery systems. Sucker-rod guide failure will lead to premature tubing wear. In extreme cases, sucker-rod guides can begin to disintegrate, which will allow small fragments of plastic to enter into the production fluids. When this occurs, the fragments can also enter the pump and plug flow lines, causing substantial operational issues. Both cases of fragment incorporation will result in elevated expenses and downtime caused by the need to repair or replace downhole equipment, which will also lead to deferred production rates.

**AN ALTERNATIVE SOLUTION**

With the CUT tests indicating that PPA sucker-rod guides were not capable of performing as reliably as thought in applications with higher downhole temperatures, Norris began searching for a new solution. They were fortunate to find one in a colourless thermoplastic polymer known as polyether ether ketone, or PEEK.

PEEK, which was originally developed in the early 1980s, possesses strong mechanical and chemical-resistance properties that are retained in high-temperature operating environments, up to 480°F (249°C). PEEK is also highly resistant to thermal degradation and attack by aqueous solutions, which are two of the notable shortcomings of PPA.

Knowing that PPA guides were beginning to fail prematurely in high-temperature wells, Norris, a product brand of Apergy Corporation, began a lengthy process to identify a better material that could be used in sucker-rod-guide construction.

The industry needed a sucker-rod guide constructed of a material that could not only handle higher operating temperatures, but also supply the long-life service that synthetic polyphthalamide sucker-rod guides had previously demonstrated. Norris’ goal was to develop a new extended-life sucker-rod guide that could perform at elevated temperatures.

After extensive research and nearly two years of field testing, the solution was found: a new type of moulded-plastic sucker-rod guide that would be built with a PEEK blend. The new PEEK-blend sucker-rod guide is an ideal replacement for PPA models in shale wells because of PEEK’s aforementioned ability to retain its mechanical and chemical-resistance properties even at very high temperatures when compared with most other thermoplastics. Specifically, when blended with other plastics, PEEK can produce reliable performance in operating temperatures as high as 480°F.
This performance capability fits perfectly into the sweet spot for sucker-rod guides that are used in continuous-duty operations in deep, high-temperature shale wells.

**ADDRESSING A PROBLEM**

Beginning in 2015, a petroleum and natural gas exploration and production company that is a major operator in US shale plays, experienced a series of sucker-rod string failures at its wellpads in the Eagle Ford shale field. In just the third quarter of 2015 alone, this end user reported that 11 strings failed with a mean time between failure (MTBF) of 461 days.

All of the failed strings were equipped with PPA sucker-rod guides. Bottom-hole temperatures in the wells ranged from 270 - 295˚F (132 - 146˚C). The failures occurred at depths of 6950 to 10,756 ft. Levels of hydrogen sulfide (H2S) ranged from 5 to 2000 parts per million (ppm). The maximum side load in the failure section was 270 lb/rod. After examination, the sucker-rod guide failures were attributed to the exposure of the PPA guides to an aqueous solution at elevated bottom-hole temperatures.

Based on its discovery that PEEK-blend guides could be a reliable solution to the failures of the PPA guides, Norris offered its PEEK-blend NHT Series Sucker-Rod Guides to this end user for testing. In creating the PEEK-blend guides, Norris incorporated manufacturing process improvements such as next-generation injection-moulding machines that feature chilled moulds and raw material dryers. These process improvements, as well as tighter quality controls, allow for the reliable production of guides that feature a homogenous microstructure, which improves their tensile strength and heat-resistant capabilities.

Specific features and benefits of the Norris PEEK-blend NHT sucker-rod guides include:
- Reduced tubing wear versus other high-temperature plastics with wear characteristics similar to base PPA material.
- A 400˚F (205˚C) continuous-service rating.
- A 480˚F (249˚C) maximum service rating.
- Superior chemical resistance in corrosive environments.
- Reduced porosity versus conventional rod-guide plastics.
- Proven sidewinder design (higher erodible wear volume with minimal fluid turbulence).
- Injection moulded for maximum adhesion to rod body.
- Separate hoppers for increased melt temperature, resulting in zero fluid contamination.

**THE RESULTS**

This end user installed Norris PEEK-blend NHT guides in 17 test wells. Six wells had alternating guides: one rod with PPA guide material then one rod with PEEK-blend NHT guide material. The other 11 wells were all outfitted with NHT guides from a depth of approximately 7000 ft up to the pump.
In the wells that were outfitted with PEEK-blend Norris guides, nearly all premature sucker-rod guide failures in high-temperature environments were eliminated. No rod strings have required replacement since initial installation – and they have been running for more than 750 days, which is already a 50% increase in run time over the PPA guides that were failing prematurely.

In summary, the user had three goals in replacing the PPA sucker-rod guides with Norris’ NHT models: first, outperform the PPA guide in high-temperature environments; second, double the MTBF when compared to the PPA guides; and third, perform as well in a high-temperature application as a PPA guide performs in a low-temperature well. The first two goals have been met, while the third is in the process of being achieved. These results illustrate that Norris NHT sucker-rod guides can outperform and outlast PPA models in high-temperature applications.

Similar results have been experienced elsewhere that PEEK-blend NHT guides have been installed:

Another South Texas operator had wells with operating conditions of 300˚F, 140 - 200 lb predicted side load and 50 ppm H₂S, experienced severe pump tagging and fluid pounding. At 261 days, the rod string parted. Norris NHT guides were able to outperform reaction-set polymers, PPS, PPS-X, and thermoplastic resins in terms of material loss and chemical permeation.

These results show that an investment in Norris sucker-rod guides produce a substantial return for well operators by extending sucker-rod service life and preventing premature tubing wear caused by guide failure. For example, in a typical Eagle Ford or Bakken shale well, remediation costs that include pulling the tubing string can exceed US$100,000. And this does not include the value of lost production. Eliminating these remediation costs and keeping the well producing more than offsets the small additional cost required to purchase premium Norris PEEK-blend rod guides.

CONCLUSION

While some operators prefer to run PEEK-blend guides from top to bottom, costs can be minimised by using PPA guides to the high-temperature zone and then PEEK-blend guides from there. Either way, operators can remove costly well-intervention, and keep the well online and producing. In the end, selecting a field-proven sucker-rod guide for high-temperature applications will reduce rod-pumping expenses.
Ever since the adoption of measurement while drilling (MWD) and logging while drilling (LWD) in the late 1960s, engineers have been challenged with providing a reliable source of downhole electrical energy. Early attempts utilised wirelines or wired pipe to accomplish the task. Wireline is essentially the extension cord for downhole drilling. In theory, it requires only a surface power source and an electrical connection to the downhole tool to work. The benefits of wireline include practically unlimited energy downhole as surface power is either readily available or easily sustained. However, the complications of maintaining a continuous connection and supporting isolated tools drove the industry to incorporate new forms of energy storage and generation. The invention of lithium-thionyl chloride (Li-SOCl₂) batteries in the late 1960s, and their adoption in the 1970s, provided one means of supplying power downhole. Li-SOCl₂ batteries have extremely high energy density, relatively good power handling capabilities, but suffer from...
safety concerns and from the inability to be recharged. Downhole generators would become the dominant source of downhole energy when operations exceeded the practical lifetime of Li-SOCl₂ batteries. While generators support much longer trips without recovery or replacement, they cannot provide energy without continuous mud flow, forcing engineers to incorporate batteries to support activity when mud flow has ceased.

These types of challenges and trade-offs have long been present in MWD and LWD but there are alternatives enabled by technology developed in recent years. FastCAP Ultracapacitors, a division of Nanoramic Laboratories, began in 2009 derived from research investigating carbon nanotubes for use in ultracapacitors. The somewhat unintentional side effect of this research was that it enabled ultracapacitors, typically limited to a maximum operating temperature of 65˚C, to operate beyond 150˚C. With funding in hand from the US Department of Energy (DOE) targeting geothermal applications, FastCAP developed what is today the only ultracapacitor suitable for downhole oil and gas exploration.

WHAT IS AN ULTRACAPACITOR?
An ultracapacitor, or supercapacitor, is any capacitor that stores its energy through an electric double layer. The double layer phenomenon enables substantially more charge storage by volume and mass when compared to other capacitor technologies. As an example, a standard ultracapacitor will typically have an energy density that is 10 - 100 times higher than that of a tantalum or electrolytic capacitor. On the other side of the spectrum, Li-SOCl₂ batteries typically have an energy density that is 10 - 100 times that of an ultracapacitor. Therefore, in terms of energy density, the ultracapacitor generally sits right in between electrolytic or tantalum capacitors and lithium batteries.

Nanoramic has re-engineered the fundamental components of the cell to survive both high temperature and high shock and vibration environments. Each cell is capable of 150˚C operation with 20 g vibration, 500 g shock survival. Capacities range from 35 F in a AA cell form factor to 350 F in a D cell form factor.

APPLICATIONS
Ultracapacitors can be used in a variety of applications within downhole exploration and production. This article will highlight a mud pulse telemetry application and then focus on voltage buffering for generator based solutions.

BATTERY AUGMENTATION
One use case of battery augmentation is enhanced mud pulse telemetry systems. The low internal resistance of the ultracapacitors make them ideally suited for high power discharge events. In mud pulse telemetry, a burst of power is needed to open and close a mud valve. Strong telemetry pulses require that the valve actuation is well timed, quick, and not hindered by particulates that may clog or disrupt the valve. Operating in parallel to a Li-SOCl₂ battery, an ultracapacitor module significantly increases the peak current handling capacity of the battery while buffering the battery from large current spikes. Benefits include a longer lasting battery pack and a higher performance mud pulse telemetry. Clever power systems could also vary the voltage on the ultracapacitor module depending on the drill depth. A low voltage conserves battery energy and could be used during shallow parts of the well. As drilling continues, pulse power can be increased by increasing the ultracapacitor voltage.

GENERATOR BUFFERING
As introduced, generators are an excellent means of providing high power downhole energy over long durations of time. The drawback of most generators is that they cannot produce power when mud flow is off, a time that is often used for sensitive measurements.
in directional drilling and well logging. Ultracapacitors offer a long lifetime, high reliability, and safe form of energy storage to buffer generator power for when mud flow is off. Throughout this example, the design and integration of an ultracapacitor module to support measurement and communication operations will be discussed.

The design criteria are shown in Table 1. Here, voltage, discharge power, and discharge period are chosen to represent a generic load profile. The analysis can be used for a range of similar applications of varying voltage, power, and time.

**ULTRACAPACITOR SELECTION**

In this example, the maximum output voltage target is 12 V. It is possible to address this requirement by incorporating a DC/DC converter at the output of the ultracapacitor module to provide a fixed 12 V rail. In this way, the capacitor module does not need to directly support a full 12 V. However, the minimum output voltage is only 5 V. Using the formula shown below, the low minimum voltage enables a relatively high energy utilisation percentage making it feasible to use the capacitor module without an additional output DC/DC converter. If higher cell utilisation is required, a DC/DC converter can discharge the cells to an even lower voltage, converting more total energy.

The voltage rating for 150˚C capacitors begins at 1 V per cell. Thus, this design will require at least 12 cells connected in series. Given that the peak power of the discharge event is relatively low, how much energy is required will be considered first.

![Figure 2. Five cell module without balancing (top) and with balancing (bottom) the time constant of convergence is estimated by the R-C time constant of each capacitor – balancing resistor network.](image)

The minimum capacitance can then be calculated using the following equation:

\[
\frac{V_0 - V_f}{V_0} = \frac{12^2 - 5^2}{12^2} = 83\%
\]

The voltage rating for 150˚C capacitors begins at 1 V per cell. Thus, this design will require at least 12 cells connected in series. Given that the peak power of the discharge event is relatively low, how much energy is required will be considered first.

\[
E = P_{\text{discharge}} \times t
\]

\[
= 15 \times 60
\]

\[
= 900 \text{ J}
\]

The minimum capacitance can then be calculated using the following equation:

\[
E = \frac{1}{2} C (V_0^2 - V_f^2)
\]

This equation demonstrates that the module must have a capacitance greater than 15.1 F. With 12 cells in series, each cell must therefore have a final capacitance of at least 71 F. It is important to adjust for degradation of the cell as it nears end of life. Most capacitors are rated for 1500 hours at their rated voltage and maximum operating temperature. At this point, capacitance is expected to have dropped by 30% while ESR will have increased by 100%. Therefore, the initial module capacitance target is adjusted up to 21.6 F. ESR of the capacitors will contribute to additional voltage loss throughout the discharge period. Therefore, for high current discharges, it is important to simulate the full discharge period considering resistance losses. Given a 12-cell module capacitance of 21.6 F, the single cell target capacitance is 260 F.

![Figure 3. Each cell part and process has been optimised for the downhole environment. Shown here are features necessary for survival in harsh environments.](image)
The cell that meets these requirements is the Nanoramic EE150-350 High Temperature FastCAP Ultracapacitor. The relevant specifications for the ultracapacitor are shown in Table 2.

It should be emphasised here that the module is being designed for a full 1500 hrs of operation. A typical moderate rate 8-cell Li-SOCl2 module under the same power conditions would be expected to last ~45 hrs. The lifetime of the capacitor module increases exponentially as the operating temperature or operating voltage are decreased from their rated maximum levels.

**SIMULATION**
A transient simulation is used to combine cell capacitance variations, ESR, leakage, and degradation. Other factors such as wiring harness resistance and protection diodes may be incorporated for more accurate results. Shown in Figure 1 is a simulated discharge at beginning of life and end of life. Even at end of life, the capacitor module exceeds performance specifications.

**CHARGING CIRCUITY**
For charging the ultracapacitor bank, a converter with output current regulation is recommended. The reason for output current regulation is that, when discharged, the capacitor voltage will be near 0 V but the series resistance can still be very low. Therefore, for an unregulated supply, such as a battery, or for a voltage controlled regulator, there is a danger of drawing too much current from the supply.

There are custom ultracapacitor charging IC’s on the market, for example the Linear Technology LTC3255, that typically incorporate both charging and balancing for a small number of series capacitors. Alternatively, any current regulated converter IC will be suitable and can be adapted for much higher voltage and power operation. A large segment of these IC’s can be found as LED drivers. One example that has been used extensively is the Linear Technology LT3791.

**CELL BALANCING**
Variations in the cell manufacturing processes and environmental exposure will lead to variations in capacitance, ESR, and leakage current between cells in the module. Generally, capacitance and ESR may vary by +/- 10% while leakage current may vary +/- 50%. These parameter variations will inevitably cause the series connected cells to operate at slightly different voltages. Divergence will begin as a function of the initial variation between cells. However, cells that operate at a higher voltage will likely age faster than cells operating at a lower voltage potentially worsening performance variation as time continues.

Whether or not a module requires balancing is only answered with the expected performance and environment of the module. Generally, for modules that undergo many high power charge/discharge cycles, passive balancing will not suffice and active balancing is recommended. For modules that may be used for a voltage bus hold-up application or a backup energy supply, passive balancing may be suitable. In some rare instances, modules may take advantage of leakage rate characteristics to eliminate the need for additional balancing circuitry.

A typical rule of thumb for sizing balancing resistors is to maintain a balancing current through the balancing resistor that is 10x the expected leakage current. In this way, disturbances in cell voltage caused by leakage current can be compensated for by the balancing current.

Shown in Figure 2 are two plots showing simulations of a module with and without resistive balancing. Without balancing resistors, cell voltages diverge until eventually the rate of voltage decay for each cell is equal. With balancing resistors, high voltage cells are discharged and low voltage cells are charged to the nominal value. The cells will not reach exactly the same voltage as the leakage currents still vary from cell to cell.

**SUMMARY**
This example has simulated an ultracapacitor module for buffering generator output power. A power discharge of 15 W for 60 seconds was selected to demonstrate the capacitor’s capability for providing sustained power for a full 1500 hours of operation.
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Increasing and maintaining production in tight oil and gas fields is key to the continued growth and development of the oil and gas sector. In unconventional wells, production rates rapidly decline to low terminal values. To maintain production, new wells are continually added to offset decline. Reducing drilling and completion costs (through greater efficiency), and extending lateral length are key for the current approach of increasing reservoir contact. Even with lateral drilling and extended laterals, only about 20% of the reservoir is effectively recovered due to production decline. Technologies that enhance and maintain production for longer periods of time enable enhanced recovery of resources and improve the return on construction costs.

To address the enhancement of far-field fracture networks, with support from the Department of Energy’s Small Business Innovative Research Program (SBIR) under contract DE-SC0013242, Terves has been developing a family of
highly-engineered lightweight proppants that offer the ability to increase and maintain fracture width in far-field fractures. Maintaining fracture width during fluid draw-down in the presence of closure stresses has been shown to produce at least 20 - 30% more oil or gas – which translates into an additional US$2 - 6 million in production revenue from a well.

Challenge
The ability to characterise, develop, maintain, and control complex fracture networks in geologic formations is essential to the extraction of oil and gas. A major contributor to production decline is the closure or blockage of fine fractures that provide connectivity to the main fracture channels. These fractures are normally unpropped, since current coarse sand proppants are difficult to transport into fine natural fractures. Acidising treatments and shear displacement are effective until closure forces are applied, but these unpropped fractures rapidly lose conductivity. Maintaining conductivity in the far-field requires advances in proppant transport, proppant engineering, and control over the proppant/formation interfaces. Terves is developing solutions in the form of lightweight, ultrafine and expandable proppants that can be transported into fine far field fractures, increase the fracture width, and then maintain the fracture width and suppress formation damage (fines formation), thus maintaining fracture conductivity (and production) for longer periods.

Key drivers for geologic resource recovery
- More efficient drilling and completion operations – reduced cost, reduced use of water, chemicals, etc.
- Increased access and surface area for access – increasing the drained area per borehole through enlarging and better control over fracture networks leading to higher production rates and improved economics.
- Increased total extraction – increasing the amount of the resource extracted from 20% to >50% or higher. This requires improved control over the long-term fracture network geometry (access), as well removal of the remaining oil through chemical and other secondary oil recovery techniques.
- Retaining hydraulic access – by delaying loss of hydraulic communication via formation damage, fines generation, and fracture closure.

Production from far-field fractures is usually lost fairly-early in the production decline period, after the hydraulically stimulated but unpropped far field fracture network loses communication with the main transport fractures and the wellbore (through either fracture closure due to formation pressures being asserted as the well is put into production, or fines production and plugging/blockage of fracture necks). The key to maintaining far-field conductivity is to transport proppant into the far-field without tip screen-out, then to offset the closure forces to maintain fracture conductivity, and to also prevent fines production and formation damage. In low Darcy formations, large conductivities are not required in the far field, but large areas must be accessed. This can be achieved using small, lightweight proppants that are able to spread contact without embedding or causing local fractures. Because of the difficulty in removing gels, gas, foam, or slickwater treatments are typically needed, without high concentrations of viscosifiers that can cause blockage or formation damage. The use of ultrafine, or even ‘nano’ swellable, active proppants will play a key role in addressing this need.

Most tight formations (those not composed of highly porous medium) have a complex natural set of fractures, which can be further extended and enhanced through hydraulic fracturing techniques. This fracture network includes large fractures, as well as a network of fine fractures. Hydraulic stimulation opens these fractures, allowing the transport of chemicals and proppants into them – while also expanding the fractures along certain preferred directions. During the process, large fractures receive the bulk of the flow, chemicals, and proppants, while fine fractures at high angles receive reduced flow and often no proppants. The development of improved tools to control the placement and flow of materials, and decrease the force application during treatment processes is essential when developing, controlling, and retaining hydraulic access to the formation.

The primary issues pertaining to current simulation methods include loss of production due to crack closure as fluid is removed (primarily related to the inability to prop fine fractures at high deviation from the main fissures), and the poor force utilisation – most of the flow and force is exerted
Shale Support operates an extensive mining and transload network strategically aligned to serve every major shale play with unmatched speed and efficiency. Frac sand reserves totaling more than 180 million tons and a logistics network with the flexibility to ship proppant via rail, road or barge means our team can quickly respond to customer’s distribution and storage needs in the ever-changing energy services market.

**Quality sand. Efficient distribution. Exceptional customer service.**
along large fissures – this can exceed 70% of the fracturing fluid, and large volumes and velocities are needed to carry heavy and large proppants, which increases water use and costs. The immense consumption of fluids is not efficient, both in supplying, pumping, and disposal/treatment during flowback and production. Expandable proppants offer a new tool which can be used to augment fluid pressure, prevent crack closure, and to apply residual forces to help control fracture network development.

The expandable solution

Terves has developed the XOProp™ proppant, a fine, lightweight proppant containing a reactive inorganic filler, such as an anhydrous oxide or reactive light metal that creates a large volume oxide, hydroxide, hydrate, or carbonate upon reaction with water, CO₂, or other chemicals available in the formation. It is based on the concept of 'engineered corrosion', like the well-known example of rusting rebar (iron forming iron oxide) cracking concrete structure. At slow rates or hydration reactions, it generates expansions. At higher rates, metal-water reactions generate heat and hydrogen pressure. At very high rates these proppants can generate in-situ explosions or propellants.

Current product specifications

- Nominally 100 mesh spherical proppant.
- Density <2 g/cc, generally <1.5 g/cc.
- >8000 psig PSI crush strength (no fines).
- >30% (up to 100% or more) expansion in 70 - 90˚C brine or freshwater.
- Expansion time of 6 - 72 hrs.
- Modulus of 0.8 - 1.5 GPa.
- Plastic yield strength of 5000 - 15 000 psig (rock strength dependent).

XOProp’s initial offering is a 70/100 mesh (150 - 200 micron) easily transportable expandable lightweight proppant that is placed at a targeted 40 - 60% partial monolayer coverage (about 0.02 lb/ft² fracture area). Over 6 - 72 hrs, the proppant expands 30 - 100%, increasing width and proppant-formation contact area to shield stresses. The plastic yield strength and stiffness of the proppant is designed to apply 1000 - 3000 psig closure counterforce to delay production decline and maintain permeability in fine fractures. The rigid conformable proppants do not embed in the formation, and do not generate fines from the formation (or proppant) during the application of closure force. Proppant transport is accomplished with slickwater or foam fracs.

Proppant characteristics and value proposition

- Large volumetric expansion in rigid (GPa) high stiffness system.
- Lightweight, transported with slickwater or gas or foam frac with low formation damage.
- Ability to expand fracture width and apply a counterforce to closure stress while retaining permeability.
- Can be produced in <100 mesh to mm sizes.
- Stiffness, plasticity/yield strength, swell timing, and operating temperature ranges can be tailored.
- ~23% increase in production over the first several years of well operation based on initial models that need further validation and refinement. This results in an additional US$2 - 6 million in revenue/well for US$200 000 - 300 000 additional completion cost.
- Can also be used as a coating and/or additive for proppant flowback, sand, and fines control, and increasing stress rating of desert and brown/local sand.
- Expandable and dissolve-expandable rigid and elastomeric materials are also being considered for applications for improving and maintaining wellbore and cement integrity, and in fluid loss control, as they can impart controlled stresses or stress-engineered volume expansion for both temporary reversible and permanent requirements.

The specific application being targeted is an expanding lightweight proppant that can enhance total recovery of unconventional (low Darcy) oil and gas formations and enhance economics of geothermal hard-rock wells. The expandable proppants enhance production by delaying closure and pinchoff of far field fractures through the following mechanisms:

- Providing a counterforce to the closure forces of 1000 - 3000 psig depending on elastic modulus, plastic yield strength, and contact area.
- Reducing fines generation/formation damage and embedment by stress shielding compared to sand proppants through increased contact area to reduce point loads.
- Widening fractures due to expansion, and transport easier because they are smaller and lighter.
- Maintaining fracture conductivity in partial monolayer applications longer than sand or acidised fractures.

Case study

During testing of a 20/40 mesh expandable and sand, with a 30% expansion (10% linear) XOProp formulation, (at 2000 psig closure stress), the proppant resulted in a 63% reduction in the loss of fracture width compared to equivalently sized sand, with a 36% reduction in loss of fracture width at 5000 psig closure stress. Flow resistance (pressure drop across the conductivity cell) after the application of 2000 - 3000 psig closure force was reduced more than 90%, with XOProp propped fractures showing 10 times the conductivity of equivalent sand loadings with monolayer and less than monolayer coverage. Electron micrographs show the resultant sand embedment and fines and debris generation, with no comparable embedment or fines generation with the expandable rigid proppants.

Conclusion

Development work sponsored by the US Department of Energy has now demonstrated techniques for managing unconventional reservoir production decline due to pinchoff of far field fractures as a result of fluid draw-down. The use of controlled rigidity (deformable), expandable ‘smart’ proppants can increase retained fracture width significantly; they demonstrated a 90 - 95% increase in retained fracture conductivity versus equivalently sized sand in less than monolayer coverage in split rock API fracture conductivity tests under applied closure forces of 2 - 3000 psig. Production simulations show a 4 - 6 month shift in decline curve, and 23% increase in total oil production against 100 mesh sand treatment in a current tight carbonate formation using a roughly 10% stage loading of expandable proppants. The use of engineered ‘smart’ or responsive proppants now gives reservoir engineers the tools to control and optimise fracture network and formation drainage over time, rather than only during the initial state created during the stimulation treatment.
Scale deposition downhole is a widely recognised and commonly experienced oilfield production problem. Once the water in a reservoir is produced, the natural chemical composition of its surrounding environment is disturbed, often causing scale deposition to occur. Scale depositions are solid deposits, which can be both organic (i.e. paraffin, asphaltenes) and inorganic (i.e. calcite, barite, halite) in nature. Halite scale in particular (NaCl or ‘salt’) was once regarded as uncommon, but has grown into a flow assurance issue that now affects a rising number of oil and gas basins across the US and worldwide. These scale deposits can cause major blockages in tubulars and proppant packs, severely limiting the efficiency and effectiveness of downhole pumping equipment, restricting oil flow and halting production. Scale remediation efforts can necessitate costly workovers and pump repairs, which lead to production downtime and lost revenues.

Joshua Leasure, CARBO, USA, describes a proppant-delivered solution to the widespread problem of scale deposition in the oilfield.
The process of scale formation

The most common scale deposits encountered in the oilfield are calcium carbonate and barium sulfate. Calcite typically forms as brine water moves from its point of origin in the reservoir, where it was trapped prior to fracturing and in a state of equilibrium. As the brine water flows towards the wellbore and out of the well, it is subject to a reduction in pressure. This causes calcite solubility to decrease and scale begins to form. This behaviour is referred to as a ‘self-scaling’ process. Barite tends to form when waters of different chemistries mix. This mixing and scale formation can occur when there are multiple producing zones or when incompatible fluids are comingled downhole. Typical offshore fields utilise water flooding to maintain reservoir pressure. The injection of seawater into the formation can also cause scale deposition.

Approaches to treating scale

Scale is initially deposited near the wellbore and treating it ranges from ‘challenging’ to ‘impossible.’ For calcium carbonate deposits, an acid solution can be used to soak the scale for a day or more – an approach that goes some way to dissolving it. However, this method requires the well to be shut-in and a crew to be mobilised to the well to carry out the work.

While production assurance and scale inhibition chemicals have traditionally been added as a liquid in the fracturing fluid, a significant portion of the chemical immediately returns during the initial flow back, typically necessitating reapplication of the inhibitor chemicals using a squeeze treatment or continuous injection. The operational expenditure associated with repeating these treatments can be substantial.

Traditional remediation of halite can be accomplished by dissolving the scale in fresh water. This means the operator needs to factor in the cost of fresh water, trucking, manpower, anti-scale additives and disposal of additional produced water. These treatments need to be repeated frequently, in the order of multiple applications per week.

Bearing in mind the drawbacks to the traditional methods for handling scale, a standalone inhibition strategy often proves to be a far more efficient and effective approach. To this end, CARBO developed 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 based on anticipated production profiles.

Proppant-delivered scale inhibition

Traditionally, liquid inhibitor added to frac fluid has a short effective period and is inefficient due to the large volume of chemicals required. Particulate chemical carriers added during frac can impair conductivity. Alternatively, SCALEGUARD is a proppant-delivered scale-inhibiting technology, comprised of a porous, ceramic proppant engineered with a controlled release technology and infused with scale-inhibiting chemicals. It has to date been deployed across the US, in every major basin including the Gulf of Mexico and Alaska, as well as Canada. 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 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 – a common risk with low strength particulate-based carriers.

Controlled release technology significantly 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. SCALEGUARD is designed to last the life of the well and effectively minimises the well maintenance and the remediation issues encountered by the well’s production team in the latter stages of the well’s life, lowering overall costs of well production.

Case studies

Permian Basin, West Texas

The operator wanted to increase production and estimated ultimate recoveries (EUR) from a well in the Permian Basin’s water-rich residual oil zone where produced water volumes averaged 4000 bpd with a 60/40 oil cut. In these operating conditions, scale deposition was a persistent and costly production assurance issue.

Solution

SCALEGUARD was pumped uniformly throughout the fracture network, blocking scale formation at its source. The technology was initially earmarked for six San Andres wells, to be completed with an average of 14 to 16 stages and stimulated with a blend of 100 mesh and 30/50 white sand pumped at an average rate of 180 000 lb/stage. CARBO specialists conducted a water chemistry analysis of the six targeted wells as a prelude to develop the MIC and placement release rate to extend the treatment length. Engineered for the individual well characteristics, SCALEGUARD was mixed with the 30/50 regular sand.

Figure 1. SCALEGUARD has a unique controlled release technology that ensures a predictable release of the infused chemical in the well. This provides a significant reduction in initial chemical washout and results in an extended treatment life.

Figure 2. SCALEGUARD technology reduces production maintenance requirements and costs, avoids workovers and eliminates the potential for catastrophic production system failures.
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Results
Since the initial treatment, no scale has been observed in the six wells, one of which was eventually completed with a field-high 32 frac stages. SCALEGUARD proved to be a cost-effective option for increasing reservoir drainage in areas where exorbitant produced water volumes pose severe production assurance issues.

Uinta Basin, Utah
An operator was experiencing persistent build-up of carbonate and sulfate scales in its wells in Utah’s Uinta Basin. The operator relied on liquid phosphonates and particulate-based inhibitors to prevent production restricting deposits, which continued to re-emerge. In this geographical area, excessive volumes of produced water are exacerbated by a long history of flooding, causing scale to form quickly and frequently. Rod pumps and downhole tubulars can be seized with scale in a matter of days. Compounding the reduced production, persistent scale build-up can reach the point where a costly squeeze is the only remediation option. The operator was looking for an alternative and longer-lasting solution that would sustain oil production for multiple years without such frequent remediation.

Solution
A field trial was arranged with five vertical wells completed similarly and stimulated with a blend of SCALEGUARD technology and 20/40 northern white sand. Beforehand, CARBO specialists conducted extensive yard tests and modelling, taking into account the water chemistry, production rate and other well characteristics, to determine the precise MIC and placement release rate.

Results
The controlled release of the inhibitor by SCALEGUARD technology has worked as designed with the five wells sustaining production for more than one year with no downhole scaling issues. After treatment, production has sustained rates achieved prior to the scale deposition. Water samples show the scale control consistently remaining well above the MIC, effectively saving the operator costs associated with oft-repeated scale remediation. The SCALEGUARD technology field trial has allowed for additional proppant-delivered solutions to counter other production choking problems within the area, such as paraffin.

Manitoba, Canada
An operator targeting the Bakken/Spearfish formation of Manitoba, Canada, was producing from a 22 stage horizontal well, comprising an aggregate 130 000 lb of natural sand proppant. After the well had been on line for approximately a year, the operator experienced a steep decline in production, which was quickly attributed to severe scale deposition. The only alternative was to pull the pumps and drill out the well to remove the scale deposits, which dramatically reduced the overall value of the producing asset.

Solution
Following a subsequent CARBO evaluation that included the specific well characteristics and produced water chemistry, the operator modified its stimulation strategy accordingly. To reduce the near-wellbore pressure drop, the sand proppant was replaced with 20/40 CARBOECONOPROP low-density ceramic proppant. To treat the produced water before it reached the wellbore, and thereby prevent scale from forming, the client pumped the SCALEGUARD proppant-delivered scale-inhibiting technology.

Results
SCALEGUARD prevented scale remediation after 12 months of production and continued treatment for multiple years. By preventing the near-wellbore build-up of scale and keeping downhole equipment free of deposits, the technology helped in maintaining productivity and avoided unnecessary costly remediation.

Conclusion
This technology can significantly reduce production maintenance requirements and costs, avoid workovers and reduce the potential for catastrophic production system failures. Furthermore, a new porous ceramic proppant-based chemical delivery system with halite inhibitor infused is currently in development and expands the types of scales that can be treated. After field trials in the North East of the US, the new technology is opening the door for applications for preventing other types of production assurance issues.

Chemically infused and encapsulated, high strength proppant such as SCALEGUARD, shows promise as not only a viable solution, but also as a superior economical choice for challenging environments, as in the Lower Tertiary of the Gulf of Mexico. This particular solution to scale inhibition has proved to be extremely easy to institute and requires little to no intervention after it has been placed. In challenging offshore and remote global locations, operators can sometimes be days or months away from being able to remediate any issues once they arise. Considering these offshore/deepwater logistical constraints and the cost of alternative scale inhibitor delivery solutions, such as chemical injection systems and remedial chemical squeezes, these proppants act as a form of ‘insurance policy’ for operators, one which prevents the scale from forming in the first place and enables them to operate the wells with an added degree of confidence in their integrity.

Figure 3. Scale-inhibiting chemicals infused within the proppant are released into the fracture only on contact with water to deliver efficient production assurance.

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In recent years, water management in support of unconventional resource plays has become more than just a matter of environmental responsibility. With the price of oil still recovering from the lows of recent years, increasingly expensive fresh water resources and the economies to be gained through produced water recycling have become common boardroom topics. Another hot topic concerns an emerging awareness of the power of automation in the field of water management. This article explores some of the ways unconventional shale play water management practices and capabilities can be improved.

It begins with a plan
Across all North American shale plays, operators are focusing on applying best practices and best-available technologies to provide water to the point of use in the field. Dedicated water handling facilities are becoming more common in support of simultaneous area-wide operations, and the layout and provisioning of these facilities is one focus of the water management plan. Additionally, in response to modern fracturing practices that include higher pressures, longer laterals and new techniques such as zipper frac and simultaneous well completions, operators are investing in water gathering and treatment infrastructure to reduce transportation, acquisition and disposal costs while maintaining the water resources they require to complete their projects.

TETRA Technologies has worked with customers to position critical water infrastructure in accordance with a water management plan that supports area operations. Figure 1 represents the water infrastructure arrangement employed during a recent reuse project. This representative layout includes fresh water storage (1), a produced water trunk line system (2), gathering and treatment facilities for produced water (3), and produced water storage and blending tanks (4). The entire arrangement is strategically located in proximity to several active frac locations (5).
The planning that supports the development of this water infrastructure increasingly includes the provisioning of critical infrastructure with the company’s automated systems and controllers.

**Comprehensive water management**

TETRA provides a range of services to transport, store, treat and recycle water for its customers. Those services were enhanced early in 2018 with the acquisition of SwiftWater Energy Services, a Midland, Texas-based water management company that had proven itself to be a valuable resource for operators in the Permian Basin. Consequently, TETRA is now in a better position to respond to the latest industry trends, including the increasingly popular use of non-potable and treated, produced water and the automation technology available today to optimise fluid processing. Today, the company offers the latest technology and expertise required to economically process alternative types of water, including subsurface saline water, produced water or effluent water.

Economics dictate that water sources should be located as close as possible within a given operating area. A key best practice at work across the industry is the utilisation of non-freshwater sources when possible, including produced water, low-quality water from underground brackish reservoirs, and wastewater from industrial, power and municipal plants. The challenge for operators is the wide variability in water quality and consistency, which necessitates careful planning, treatment and processing before use in fracturing operations. TETRA Technologies’ systems have been developed specifically for handling the high variability inherent with non-potable water supplies, which makes it possible for operators to optimise water resources and minimise disposal volumes.

**Optimised temporary and permanent transfer**

In addressing the age-old problem of getting water from ‘A to B’, the company provides a range of solutions for operators. In addition to other fluid management services, construction services for water and wastewater pipelines up to 30 in. in diameter, along with repair services for existing pipelines are also available.

Tetra provides fluid and water transfer solutions for hydraulic fracturing operations through 8, 10 and 12 in. lay-flat hoses, which meet the highest industry and environmental standards to help ensure no-leak operations. Experienced team leaders perform site assessments and hydraulic calculations before designing a plan that efficiently positions hose, manifolds, pumps, and road crossings in order to meet customer’s needs while avoiding negative environmental impacts.

For 3 in., 4 in., and even larger poly pipe specifications, the company serves as a turnkey contractor for a wide variety of jobs. The high-density poly pipe is lightweight and flexible, provides resistance to abrasion and corrosion, and is welded with the latest fusion techniques. It can be positioned above ground or trenched and buried.

The most significant developments in the fluid transfer business, however, relate to the economies to be realised through automated technology. Automated pump systems offer cellular-based communication, pressure limit controls, remote monitoring, real time data access, and data logging to verify results. Lower fuel and labour costs, paired with demonstrably higher overall efficiency, have positioned automated solutions as a new standard in fluid transfer.

**On-site water storage**

TETRA’s storage solutions ensure drilling and completion operations have a sufficient on-demand water supply onsite. The company offers above-ground storage tanks (ASTs) that are easy to assemble and engineered to the highest standards. The above-ground impoundments are reusable, versatile, and easy to relocate. The ASTs are polyethylene-lined and can be used in collaboration with the water transfer services or contracted separately.

The company’s pit lining service utilises a wide range of polyethylene liner services (up to 60 mm) that fully comply with all applicable EPA regulations (Figure 2).

In addition to the pit lining services, the company provides a variety of secondary containment services to safeguard against costly leaks, spills, and accidents. The containment structures may be
constructed with earthen berms, formed by experienced personnel. Another option includes portable structures placed around tanks, pumps, and equipment, complete with the appropriate liner.

**Water treatment**

Water is the primary resource used in hydraulic fracturing and operators require the highest standards when formulating frac fluids. TETRA's advanced water treatment system generates an EPA-approved biocide, chlorine dioxide (ClO₂), to prevent and eliminate 100% of bacteria in fresh water, flowback and produced water. The system utilises a two-precursor method to produce ClO₂, which is then typically injected 'on the fly' into the target water stream for continuous treatment. Furthermore, since the system generates ClO₂ through the flow of water in the transfer line, the unit stops when the flow stops, ensuring a safe working environment. Other additives, such as BioRid® water treatment technology and TETRAClean™ oxidising technology, are fast-acting and quick to degrade after killing bacteria as frac water moves through the tanks.

The advantage to this type of treatment as compared to batch treatment is that the chemicals treat 100% of the water and not just that portion of the water column in the frac tanks.

In unconventional shale plays, produced water is transferred to a centrally located gathering and treatment facility, where it is stored in above-ground storage tanks. On-site analysis is critical, but lessons learned and experience within the specific shale play pay dividends for operators. For instance, the company’s experience in the Permian Basin allows technicians to anticipate produced water arriving at the facility with high levels of total dissolved solids (TDS) and total suspended solids (TSS). Additional components include dispersed oil and grease, heavy metals, radionuclides, dissolved gases, and bacteria, as well as traces of chemical additives used in production, such as biocides, scale and corrosion inhibitors, and emulsion and reverse-emulsion breakers.

An additional level of treatment is provided by oil recovery after production technology (ORappt™) water/oil separation units (Figure 3). These stand-alone, mobile units facilitate the separation with a chemical additive and deliver water with only trace amounts of oil at 50 - 100 ppm. The system allows operators to save money on disposal while making money through the sale of captured oil. In several cases, the volume of reclaimed oil has almost paid for the contract.

**Water blending**

Often there is not an endless supply of produced water aggregated in practical areas, so fracking companies use a blend of local fresh and produced water. The latest, most sophisticated frac-fluid systems perform optimally with water that exhibits uniform TDS and chloride levels. Large spikes over or under the nominally required TDS and chloride levels hinder cross-linking performance and reduce cost-efficiency in the form of chemical over-usage, thus negating any savings realised through recycling produced water. The goal of blending, therefore, is to use all the available produced water, as it represents a known cost saving under the right circumstances. To be able to achieve this optimal reuse, the blended water must be of consistent quality and must remain stable in terms of TDS and chloride concentrations.

TETRA’s automated frac-water blending system (Figure 5) is designed to provide accurate parameter-based blending and consistent blend quality, whether directly filling frac-water tanks or transferring water to another location. This system permits accurate and consistent blending of different sources of water in real time, removing the need for intermediate storage. Chemical injection ports are also available to be used for chemical addition upstream of the blending chamber. The typical automated blending setup is shown in Figure 4.

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**Case study**

Recently, the use of automated pumping technology enabled one Delaware Basin customer to achieve 50% labour savings and up to 60% savings in fuel costs during transfer operations. Using four pumps, the company was able to reduce costs and increase productivity for its customer while affording constant system visibility and pressure protection. For this operator, the automated controls, system optimisation and event mitigation translated into significant bottom line savings.

**Conclusion**

In the Permian Basin and across all North American shale plays, the combination of operators, fracking companies, frac-chemical schemes, and water qualities is ever changing. Some operators do not consider high-level blending accuracy to be necessary in their circumstances. Others demand it. However, all parties agree that the reductions in operating expenditures to be realised through automated control systems are significant. After all, dramatic reduction in fuel and labour costs paired with a rise in overall system efficiency speaks for itself.

These new technologies represent an opportunity for operators to identify previously hidden economies within already stretched-thin operating budgets. As has always been the case, developments drive the kind of savings that become the basis of real competitive advantage moving forward.

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**Figure 4.** Automated blending components. (1) Fresh water inlet; (2) Produced water inlet; (3) Automated blending controller; and (4) Blending manifold.

**Figure 5.** Automated blending controller and manifold.
DIGGING DEEPWATER

Clement Mochet and Dan Pedersen, Vryhof, Norway, review five key criteria for mooring and anchoring success.

As activity in the offshore sector continues to increase – albeit at a slow pace – offshore operators, drilling contractors and EPC companies are facing pressures like never before to increase efficiencies and revenue through new technologies and value-added services. This must also take place within the current capital-constrained environment.

Whether it be for floating production storage and off loading units (FPSOs), floating storage and regasification units (FSRUs), semisubmersibles, or fixed platforms, all services, hardware and software must be put under the microscope to ensure maximum operational effectiveness.

Mooring and anchoring is one such example. When the offshore market was buoyant, mooring and anchoring was viewed primarily as something that just ‘had to be done’ to ensure that infrastructure was secure and in position to drill and produce oil and gas, today much more is demanded of mooring and anchoring in terms of improving commercial operations.

Yet how can this be achieved?

This article details five key criteria for success in mooring and anchoring operations and how Vryhof, a provider of total mooring solutions; Deep Sea Mooring, a provider of temporary mooring; and Vryhof Anchors, a provider of permanent mooring and anchoring, are delivering.

Asset integrity

Asset integrity covers all elements of the project lifecycle including equipment, people, processes and specialisms and is a vital element of today’s mooring operations.

As a result, Deep Sea Mooring has recently entered into an agreement for the development of mooring integrity management systems for offshore operations in a collaboration with Diamond Offshore Drilling Inc.

One key element of mooring integrity is that all mooring components require regular inspection and servicing throughout their operational life to ensure the very highest performance standards. This includes everything from mooring lines, such as chain, wire rope and synthetic fibre, through to connectors, such as shackles and swivels, and other ancillary equipment.

To this end, Deep Sea Mooring allows clients to access a full-service history of every single mooring component and also has a radio-frequency identification (RFID) marking and identification system for the complete traceability and identification of all equipment. As well as improved mooring integrity, this leads to greatly reduced risk from misreading identification information.
and correct documentation, less effort needed to handle equipment, and a crucial reduction in operational time when it comes to pre-lay operations and rig moves.

Deep Sea Mooring also provides DNV GL-certified chain inspection services. Inspection results can also be reported directly on tablets and smart phones, are supported by HD video cameras with WiFi connection, and final documentation is immediately completed when the last link leaves the inspection unit.

**The need for precision**

Precision in mooring and anchoring operations is also vital.

With operations taking place in mature areas, such as in the North Sea, and the need to navigate around existing subsea infrastructure, such as pipelines, wellheads and umbilicals, mooring and anchoring arrangements must be more precise and accurate than ever before.

With this in mind, Deep Sea Mooring’s advanced distance and positioning system (ADAPS) is a powerful tool for monitoring real-time anchor positioning – a crucial factor when the distance between the anchor and any subsea infrastructure is critical.

ADAPS uses a specially reinforced transponder fitted to the anchor to monitor anchor position and seabed penetration during installation. The transponder can be used to verify correct positioning and orientation in accordance with mooring and geotechnical analyses in addition to reducing and sometimes eliminating the need for ROV work during pre-lay operations and rig moves (resulting in cost and time efficiencies).

This need for precision is also reflected in anchor designs and deployments. Vryhof Anchor’s STEVTENSIONER® chain-shortening clutch technology, for example, enables operators and contractors to install anchors with smaller leads in more constrained areas. This also allows operators to use smaller and cheaper vessels in mooring installations, allows two opposing anchors to be cross-tensioned simultaneously, and brings down installation time by up to 40%.

**Engineering expertise**

Engineering expertise is also a crucial part of effective mooring and anchoring today, not just in the design and construction of products and equipment.

Such expertise includes mooring or dynamic positioning analysis for floating structures, thruster assisted mooring analysis, and vessel motion analysis that includes; for example, wave drift coefficients and response amplitude operators (RAOs) are used to predict the behaviour of a semisubmersible drilling unit or an FPSO.

Deep Sea Mooring is also a leader in forecast response analysis where motions are predicted in addition to weather. One application is to forecast gangway motions for different headings of floating accommodation units (known as ‘flotels’) to avoid disconnections and increase connectivity.

In one North Sea application, availability analysis provided by Deep Sea Mooring saw the input of hindcast data – over 50 years of historical weather data – in order to estimate the expected availability of the flotel at a specific location. Over the course of a few months, this led to an increased gangway connectivity of 2%. The flotel’s ability to house hundreds of personnel on high day rates demonstrates how engineering solutions can lead to significant cost savings.

**Operational know-how and global deployment**

Another key criteria for operations today is global operational ‘know-how’ and the ability to deploy mooring and anchoring operations as and when needed and in all parts of the world.

Deep Sea Mooring and Vryhof Anchors have seen a number of new contracts in Norway, Australia and Trinidad. On the Norwegian Continental
Shelf, Deep Sea Mooring is providing pre-lay mooring products and services to the Deepsea Bergen semisubmersible drilling rig, operated by Austrian oil and gas company OMV. The company is also serving numerous operators and drilling contractors with pre-lay and mooring services throughout the North Sea.

Deep Sea Mooring has also secured contracts offshore Australia – one to provide turnkey pre-lay mooring solutions to the Transocean GSF Development Driller 1 – a continuation of previous work for Quadrant Energy – and the other for Cooper Energy, the first time Deep Sea Mooring has secured contracts in Cooper’s main target drilling area – offshore Victoria.

Furthermore, the two companies have recently commenced operations for Maersk Drilling and the Maersk Developer rig in Trinidad. This consisted of providing high quality mooring equipment, mobilisation and demobilisation services, mooring design including mooring analyses and geotechnical assessments and the STEVSHARK®REX anchor to block E of the East Coast Marine Area (ECMA).

The project will be served from Deep Sea Mooring’s Norwegian base, demonstrating the company’s ability to deploy quickly and effectively anywhere in the world.

**Pushing the boundaries**

The last criteria for mooring and anchoring operations the capacity for pushing boundaries. One example of this is the STEVSHARK REX anchoring solution.

Previously, hard soil conditions caused significant operational and cost challenges in anchoring operations. Multiple anchors and complex arrangements were often required and anchors sometimes needed to be redeployed a number of times with an impact on both drilling, production and costs.

Launched at the Offshore Technology Conference in Houston in May 2017, the new anchoring solution with its fluke and shank geometries is designed for application in the hardest of soil, with testing showing a 47% increase in holding power compared to other anchors.

Targeted at the oil and gas, offshore construction, dredging and marine renewables energy sectors, the anchor is having an almost immediate impact, enabling operators to develop fields and renewable projects which – until now – could not be economically developed using conventional moorings.

For some time, mooring tended to be focused on deep waters and usually soft soils. Over the last few years, however, operators have moved towards more remote areas in shallower waters where harder soils are more common. The anchor expands the suitability domain of drag embedment anchors in challenging geotechnical areas.

**Applications**

In addition to successful testing in the North Sea and the UAE, further deployments have led to a number of deals for the STEVSHARK REX – ranging from 3 to 60 t – within a period of just a year and confirming that the new anchor has become the industry standard in hard soils.

As well as Maersk Trinidad, other deployments include long-term mooring systems (FPSO, FSRUs), cutter suction dredging vessels, installation barges and even floating marine renewable devices from the North Caspian Sea to the North Sea, and from the Indian Ocean to the Caribbean.

Vryhof Anchors also initiated an anchor test at four different locations within the Angel oilfield in the North West Shell of Australia. The tests were executed in cooperation with the Australian oil and gas company Woodside Energy with the Angel Field selected due to the presence of calcarenite – a cemented rock which can be brittle and hard, making it very difficult for an anchor to embed. All four tests were faultless, the anchor being able to keep the 243 t bollard pull AHTS vessel in position during proof load tests.

Another customer is offshore EPC company CNGS Group. “Formerly we used concrete anchors and 18 t delta flipper anchors for mooring purposes but due to the big weight and size we decided to buy the 3 t version of the STEVSHARK REX,” said CNGS Group Construction Manager Levgenii Ivankiv (operating in the Caspian Sea). He continued: “Apart from the huge holding capacity, the anchor is easy to handle, the weight is relatively light, and it needs less space on the aft deck of the anchor handler. We do not have to go back and forth all the time to harbour to reload.”

Finally, independent oil and gas company. Perenco Congo SA recently awarded Vryhof Anchors a contract for the delivery of twelve 16 t STEVSHARK REX anchors with internal and external ballasts. The anchors will be deployed to support the La Noumbi FPSO in an area where the seabed is irregular, due to hard outcropping sediments and where there is presence of pockmarks interpreted as remnants of dewatering and/or degasification processes within the hard sediments.

**Improving operations, managing costs**

In today’s cost-conscious and challenging marketing environment, it is more important than ever for product and services companies to the oil and gas sector to deliver in improving operations and managing costs.

Companies are achieving this through a combination of asset integrity, precision, engineering expertise, operational know-how and global deployment capabilities, as well as a commitment to pushing the boundaries of mooring and anchoring.
In the oil and gas industry, the flow of liquids and gases must be monitored during every phase of exploration, production and transportation. Upstream operations, in particular, require the highest flow measurement accuracy and reliability, as well as long-term stability and a low cost-of-ownership.

During the exploration and drilling stages at oil and gas fields, accurate and dependable flow metering equipment is essential to ensure production is optimised.

Peter Vander Grinten and Jim Braxton, Badger Meter, USA, investigate electromagnetic flow meters as a solution for demanding oilfield applications.
This article describes how instrumentation manufacturers have responded to the needs of oilfield operators by enhancing the practice-proven electromagnetic flow meter to meet today’s demanding flow measurement requirements.

**Current climate**

In today’s oil and gas market, it is a constant challenge to keep a balance between operations, maintenance and compliance, while also delivering production targets on budget and schedule.

Fluctuating prices of crude oil have reduced the profitability of exploration and production. However, experience has shown that employing new and improved measurement technologies can lower operating costs by improving efficiency.

Oil and gas producers are under pressure to meet stringent environmental regulations affecting oilfield operations. Increasingly, they are seeking solutions for treating produced water and other by-products at the drill pad without incurring the expense of off-site disposal.

A key priority for upstream companies is to minimise labour-intensive operations, reduce trips to the field by service personnel, and lower costs through low-maintenance metering of production processes.

Many different technologies are used to measure flow rate in oil and gas applications. Differential pressure flow meters are among the most common, but they are sensitive to pressure changes. Coriolis flow meters can provide high accuracy, but they are large and expensive. Ultrasonic flow meters are reasonably small and low cost, but have limited accuracy.

In many cases, older mechanical flow metering techniques do not provide the efficiency or reliability that oilfield operations demand. Petroleum producers need a measurement technology that can deliver flexibility and accuracy to compete safely and cost-effectively in the current competitive environment.

**How the technology works**

Electromagnetic flow meters measure the velocity of conductive liquids in pipes, such as water, acids, caustic, and slurries. They are the solution-of-choice for various upstream oil and gas liquid applications due to their accuracy and hazardous area approvals.

Although there are numerous types of electromagnetic flow meters available for measuring liquid flow rates, all of them function according to the fundamental principles of Faraday’s Law. In the meter, a magnetic field is generated and channelled into the conductive liquid. The flow of this liquid through the magnetic field causes a voltage signal to be sensed by electrodes located on the meter’s flow tube walls. When the fluid moves faster, more voltage is generated. Faraday’s Law states that the voltage generated is proportional to the movement of the flowing liquid.

Modern electromagnetic flow meters are comprised of a detector and converter that together measure flow. The detector is placed inline and measures the induced voltage generated by the fluid as it flows past electrodes in flow tube. The converter takes the voltage generated by the detector, converts it into a flow measurement displayed as a local rate and total, and transmits that information to a control system.

The electromagnetic measurement technique eliminates the need for moving parts, which can lead to performance and maintenance issues when used in fluids with high solids content. Electromagnetic meters measure virtually any conductive fluid or slurry, and are known for extended turndown and excellent repeatability.

Some electromagnetic flow meters have been designed to achieve ±0.25% accuracy. Their use of a non-intrusive, completely open flow tube virtually eliminates pressure loss. The meters are relatively unaffected by viscosity, temperature and pressure when correctly specified. They also carry intrinsically safe and explosion-proof certifications that are mandatory for usage in the oil and gas industry.

Recent developments in electromagnetic meters combine general-purpose detectors with amplifiers to enable significantly improved signal processing capabilities. The latest design enhancements also provide a high signal-to-noise ratio, thus ensuring measurements remain accurate and stable without increased damping.

**Typical industry applications**

Electromagnetic flow meters are a reliable, cost-effective solution for aggressive chemicals and slurries, and provide highly accurate volumetric flow measurements in support of various oilfield processes. They are aggressively growing in oil/water separator, fracking water, drilling mud and produced water applications.

For example, oil production requires millions of gallons of water. Water management is essential for operating wells as economically as possible. Besides sourcing, transportation and storage, there are different ways to handle water, wastewater and other by-products.

Water produced in well operations is highly conductive, and as such, an electromagnetic flow meter is one of the most popular approaches for measuring its flow. The water from wells must be transported to an offsite facility where it can be treated for re-use or disposed of. The costs associated with these processes can adversely affect the economics of the producing wells, thereby discouraging further development and leaving substantial reserves unrecoverable.

Due to sediment and particulates in produced water, a flow line may need to be pigged, making the
electromagnetic flow meter an ideal choice. Because these meters have no moving parts in the line, they can be pigged without shutting down the process to remove and reinstall the unit.

Recent developments in produced water evaporation technology provide operating companies with an efficient, economical and environmentally responsible way to minimise wastewater transportation and disposal. Key to this solution is accurate measurement of the evaporation process provided by electromagnetic flow meters.

During the operation of a produced water evaporator, the volume of high total dissolved solids (TDS) water entering the system is metered, followed by a measurement of the amount of salt crystals or concentrated water exiting the unit. The delta of these two measurements is used to calculate the evaporation total, which is the basis for a per barrel service charge billed by the evaporator system provider to the oilfield operator.

Accurate flow data is particularly useful in enabling remote operation of the evaporator system without the need for a full-time operator – simplifying site personnel training and reducing overhead costs. Additionally, a programmable logic controller (PLC) can employ flow measurement information to automate the evaporation process and present relevant information on a human-machine interface (HMI).

Hydraulic fracturing is another common application for electromagnetic flow meter technology. During this process, a mixture of abrasive sand, gel and/or water is pumped into underground rock layers where oil or gas is trapped. Gelling agents are used for lubrication to increase fluid viscosity and make it better able to carry sand. This is a key step in holding fractures open. Additional chemical injections are used to reduce friction, attack microbes and minimise equipment corrosion.

By using electromagnetic flow meters, operators can maintain precise control of the fracturing fluid and the blending of additives. This application wears out many flow meter technologies and can result in an unstable flow signal, making the measurement unusable. Once the fracturing process is complete, production can begin.

During drilling and wellhead installation, precise control of the flow rate of drilling mud going down the borehole to cool the drill bit is a critical step in preparing the well. The drilling mud is typically a mixture of water, sand and a range of chemicals. The flow meter used in this application must be able to withstand abrasive materials as well as harsh environmental conditions.

The use of electromagnetic flow meters to measure drilling mud can allow oilfield operators to meet rigorous production requirements, reduce risk and avoid unnecessary downtime. The meters utilise long-lasting detector lining materials to ensure resistance to chemical corrosion and abrasion, resulting in extended service life. Unlike many other flow instruments, they have no rotating parts inserted in the pipe. This can help do away with premature wear, frequent maintenance and associated service costs.

Finally, cloud-based software solutions paired with wireless electromagnetic flow meters enable unmanned monitoring of produced water consumption, storage and transportation at remote oilfield locations. These systems utilise endpoints to capture interval meter reading data through cellular, fixed network, or mobile communication technologies. They employ data from the wireless mag meters to provide operators with readings of flow rates and hourly/daily/monthly totals, tank levels and other key parameters without visiting the well site. Production decisions can then be made at a central operations centre to help optimise large producing fields.

**Benefits to operating companies**

Whether it is improving accuracy, decreasing system maintenance or meeting the demands of challenging liquid conditions, electromagnetic flow meter technology delivers the performance that critical oil and gas applications require.

There are numerous benefits to using electromagnetic flow meters to perform fluid flow measurements in oilfield operations. They are generally non-invasive and have no moving parts, reducing the risk of breakdowns and the frequency of repairs. A decrease in flow meter pressure is also usually no greater than that of an equivalent pipe length, reducing piping costs.

Some of the other major advantages provided by electromagnetic flow meters include:
- Relatively low electrical power usage.
- Abrasion-resistant liners for measuring erosive fluids.
- Handles changes in temperature, density, viscosity, concentration and electrical conductivity.
- Compatible with both very low flows and very high volume flow rates.
- Measurement of multidirectional flow, either upstream or downstream.
- Maintenance-free operations reduce asset lifecycle costs, eliminate truck rolls and minimise the need to send personnel into the field.
- Available in large pipe sizes and capacity as well as in several construction materials.

Once an electromagnetic flow meter has been calibrated with water, it can be used to measure other types of conductive fluid with no additional correction. This provides an advantage over other types of flow meters.

**Conclusion**

Oil and gas companies often deal with troublesome applications, including produced water and fracturing fluids. Such applications can be difficult for traditional flow measurement instrumentation to handle.

Sticking to the old adage of ‘if it ain’t broke, don’t fix it’ – and not utilising the best available technologies – could cost petroleum producers and other support companies millions of dollars. For many oilfield operators, advanced electromagnetic flow meters are the meter of choice when considering cost, accuracy and the service life of installed equipment.

![Figure 2. Unmanned upstream monitoring can be accomplished using cloud-based solutions paired with wireless electromagnetic flow meters.](Image)
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- Wireline logging
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