HARTENERGY

2016 Artificial Lift Techbook

A supplement to E&P

E&P

Artificial Lift
The 2016 Techbook

A supplement to *E&P*

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Hart Energy's Techbook Series

The 2016 Artificial Lift Techbook is the ninth in a series of techbooks in which Hart Energy provides comprehensive coverage of effective and emerging technologies in the oil and gas industry. Each techbook includes a market overview, a sample of key technology providers, case studies of field applications and exclusive analysis of industry trends relative to specific technologies.

To learn more about E&P technology trends, visit *EPmag.com*.

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A lone pump jack at work in the Permian Basin scrub keeps production flowing. *(Photo by Tom Fox, courtesy of* Oil and Gas Investor*)*

Global Artificial Lift Market Growth Slows

Impact of low oil and gas prices on the artificial lift market is felt but not as drastically compared to other market sectors.

By Richard Spears
Spears & Associates Inc.

The oil field has been hurt by low oil and gas prices over the last two years; artificial lift, however, is one of the better performing sectors. Artificial lift is a $10 billion segment, or 4%, of the $280 billion oilfield equipment and service industry.

Spears & Associates has been measuring oilfield markets since 1965. The global artificial lift market's record year, 2014, saw $15.6 billion in sales, up from $4.5 billion a decade earlier. But constantly declining oil prices during 2015 and a dour outlook for the current year will set up a 2016 market of just $10.4 billion.

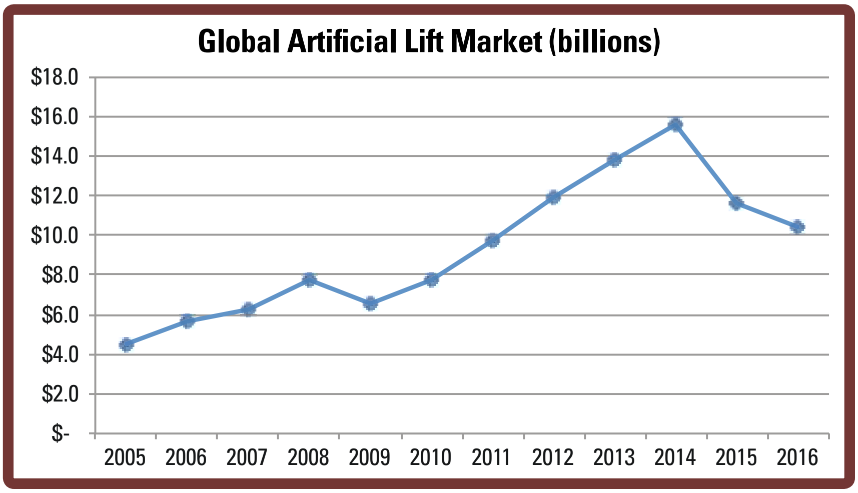
Two-thirds of the artificial lift market is found in North America and about half of the North American artificial lift market is driven by new well drilling. With new well drilling in the U.S. falling more than 50% since the 2014 peak, one-quarter of the demand for lift equipment disappeared in 2015.

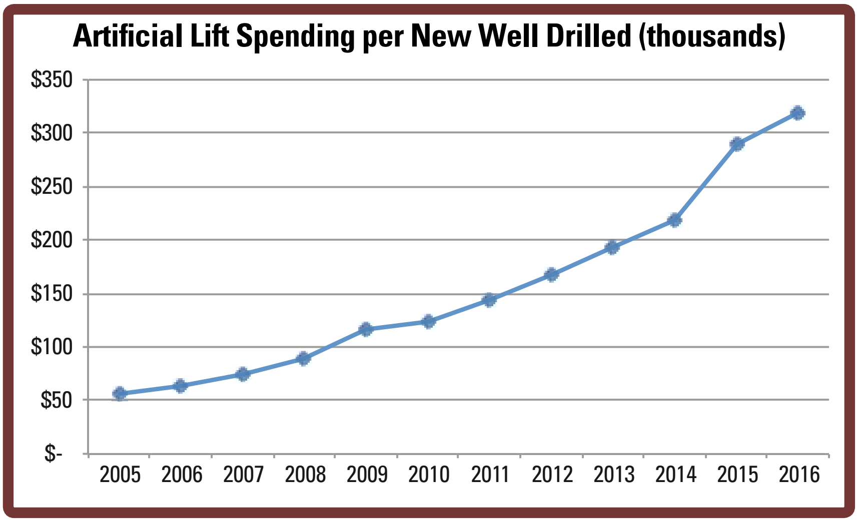
The need for artificial lift systems like this Bakken-based beam pump continues in spite of low oil prices. *(Photo by Stephen Collector, courtesy of* Oil and Gas Investor*)*

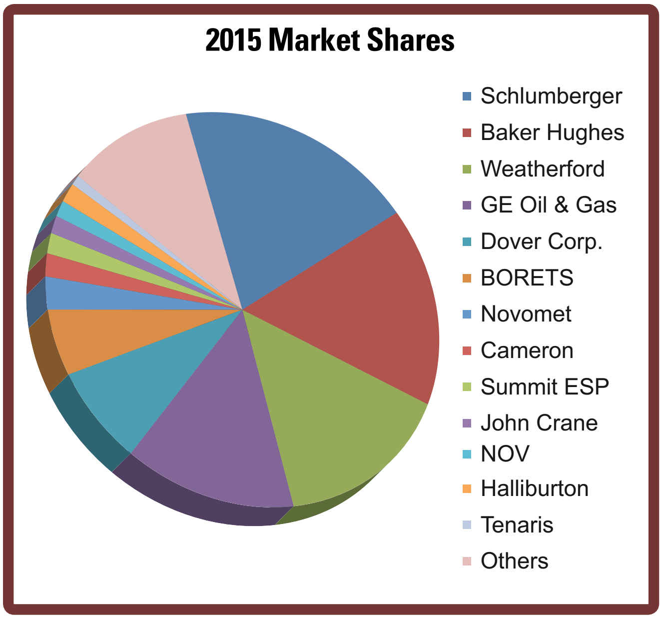
One year ago, Spears projected a 2015 artificial lift market of $12.5 billion, but the fall was harsher than expected, largely because oil prices kept declining. In 2009, which was the last market downturn, the artificial lift industry fell by 16%. By the end of the current downturn, the lift market will have fallen 35%. As tough as that is, the broader oilfield equipment and service market will fall more than 40% during the same period, and the worst segments will be down 80%. Lift is doing better than most.

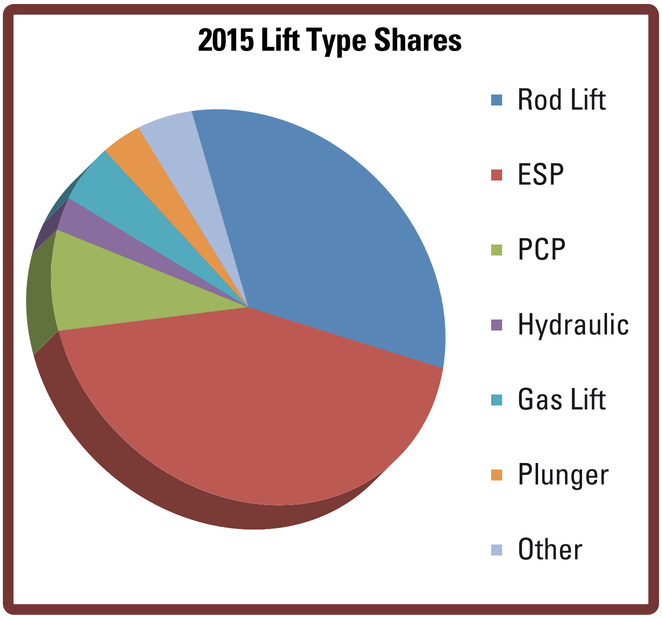
The use of artificial lift is growing more intense each year. Spears uses the simple ratio of artificial lift market dollars to total new wells drilled each year to quantify this growing intensity of use. As the "Artificial Lift Spending per New Well" chart shows, the amount of money spent on artificial lift each year per new well drilled has grown from just $50,000 per new well in 2005 to greater than $300,000 in 2016. The trend has been developing for decades, and Spears expects it to continue far beyond 2020, when the ratio will approach $500,000 per new well drilled.

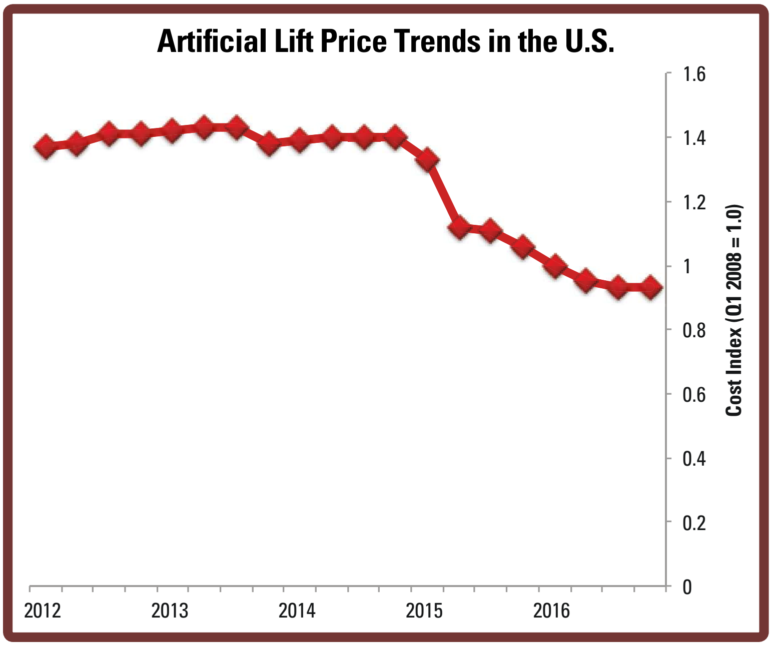
The artificial lift market is highly dependent upon sales of replacement pumps to wells that were drilled over the last 50 years,











wells that are still producing. The "Artificial Lift Spending per New Well" chart does not mean that each new well sees $325,000 of artificial lift spending. However, the industry's surge toward oil well drilling in the U.S. has been a big driver of this increasing intensity of artificial lift spending per well.

Schlumberger, via acquisition, is the current artificial lift market leader. After adding Cameron's lift product line to its own, Schlumberger's share will be 21%. If Halliburton is able to complete its acquisition of Baker Hughes, Halliburton will stand in second place with 18%. Weatherford will remain in third with 15%.

Spears' research points to six main types of lift system: rod lift, electric submersible pump (ESP), progressing cavity pump (PCP), hydraulic, gas lift and plunger. Since production-related "rope, soap and dope" and automation/monitoring systems also will be sold through many of these lift companies, Spears includes an "other" slice of the lift pie. For rod lift, 2014 was the peak year, but that lift technique has been declining in favor of ESP and PCP.

The price of an artificial lift system was fairly stable from 2012 through 2014, but heavy discounting started with the decline of oil prices and today lift products are sold for about 30% below their peak prices of two years ago.

Obviously, oil and gas development in North America has evolved over the last 100 years. A vast majority of onshore wells were drilled on a unique, dedicated pad: one pad, one well. Scattered throughout a developing oil field, one would find multiple well pads that ranged from 1 acre to 3 acres in size.

The success of horizontally drilled wells and multiple-stage fracture jobs onshore saw operators taking a page out of a wetter playbook. From large offshore platforms, several wells could be drilled and directionally steered to tap a reservoir from miles away from a single structure. While the onshore industry was geared to drill one well per facility, offshore could drill four, eight or 12 wells from a single facility.

Engineers sought ways to bring lean manufacturing to the drilling and completion process onshore. Multiple well pads provided the best solution to this need, as evidenced by its wide adoption across every major horizontal play in the U.S. One Colorado well pad drilled in 2015 has 25 wellheads, for example.

It is when artificial lift enters the picture that problems are introduced into the equation. While one drilling rig can drill all the wells, one fracturing crew can fracture all the wells and one coiled tubing unit can clean out all the wells, each well still requires a unique, dedicated lift system. One well, one lift system.

Two conditions might be driving operators toward less common, newer technology linear lift systems: proximity to urban living centers and the technical need for long-stroke rod lift systems. The look of the linear system technology is less intimidating since large pieces of steel are no longer whirling around and moving up and down. Spears sees the artificial lift industry combining these new types of lift technology with older, proven technologies as time goes by.

For 2016, Spears is forecasting a declining new oil well drilling number due to sufficiently high quantities of oil being delivered from within the U.S. market. After 2016, the oil oversupply should remedy itself and drilling should again rise. Meanwhile, ESP spending per new oil well continues to rise, helping the ESP market remain relatively stable while drilling drops. ■

Players Keep the Progress Pumping

These artificial lift key players stayed ahead of the game the past year via new technologies and services.

By Ariana Benavidez
Associate Managing Editor

Baseball is a simple game. Like the skipper said in *Bull Durham*, "You throw the ball, you hit the ball, and you catch the ball." While it is no game, making a living in the oil business is similar to baseball. You drill the well, you produce the well, and you send the oil down the sales line. Another is that both require a team dedicated to safety and hard work necessary to attain success. The following section is a roster of the leading players in the artificial lift market and an overview of their technologies and services ready to help oil and gas production teams knock low flow out of the park.

AccessESP

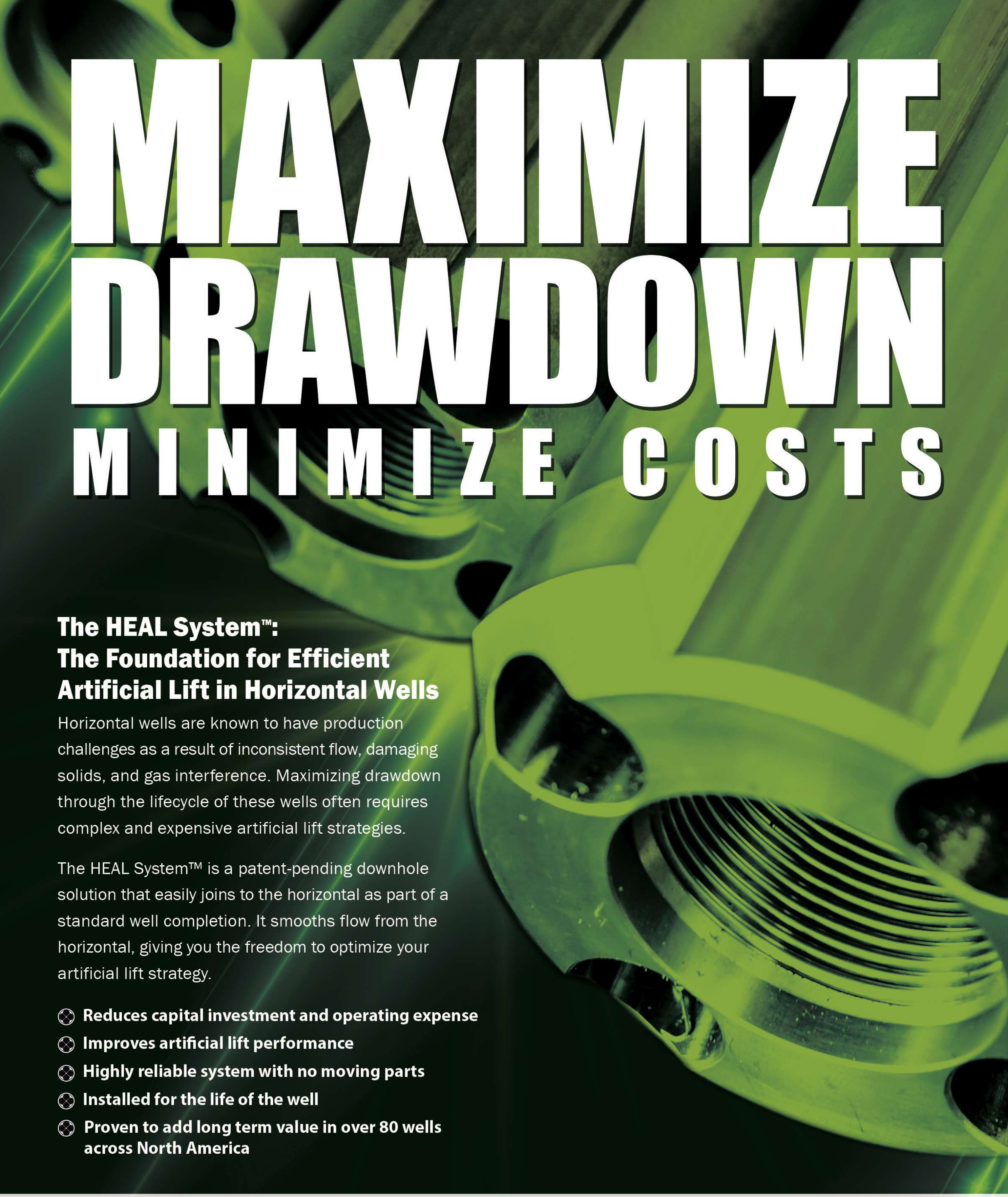
Access ESP is a provider of rigless electric submersible pump (ESP) conveyance products. The company combined two technologies—a permanent magnetic motor and a side-pocket wet connect system—into one tubing-mounted permanent completion and a slickline retrieval assembly. Running and retrieving an ESP is now similar to running a production logging tool or replacing a gas-lift valve. The company's technology makes the retrieval and replacement of an ESP system through tubing, using conventional slickline processes and equipment. No rig is required.

AccessESP's equipment can be installed as a contingency for future ESP installations. The fullbore permanent completion can be deployed at the time of the initial completion. At any time in the future, an ESP can be installed using simple slickline operations. Typically the replacement can be completed in less than 72 hours. The technology provides fullbore access below the ESP system for easy remediation of the lower completion and reservoir.

AccessESP offers a simple wellsite rigup for quick installation and replacement in the field. *(Photo courtesy of AccessESP)*

Baker Hughes Inc.

Baker Hughes' artificial lift products and services include electric submersible pumping (ESP)


MAXIMIZE DRAWDOWN
MINIMIZE COSTS
The HEAL System™:
The Foundation for Efficient Artificial Lift in Horizontal Wells
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.
Reduces capital investment and operating expense
Improves artificial lift performance
Highly reliable system with no moving parts
Installed for the life of the well
Proven to add long term value in over 80 wells across North America

systems, progressive cavity pumping systems, horizontal surface pumping systems, gas-lift systems, surface electrical control systems, and monitoring and automation services.

One of Baker Hughes' latest artificial lift offerings include the FLEXPump series of ESP systems, which are designed to provide operators with operational flexibility in dynamic well conditions to minimize ESP system changeouts and nonproductive time. The pumps can be applied to conventional oil fields, low flow rate mature oil fields and unconventional resource plays. The pump designs reduce the total hydraulic thrust in both upthrust and downthrust conditions allowing the pumps to operate in a wider operating range.

In addition, the FLEXPumpER extended-range pump provides a wide operating range for ESP systems in applications with rapid production declines. This pump is designed to expand the operating range of the ProductionWave FLEXible production offering for unconventional oil wells. The FLEXPumpER offers a flow range from 50 bbl/d to 2,900 bbl/d.

Another product released in the last year includes the company's CENesis PHASE multiphase encapsulated production system (released in December 2015). The product is designed to help operators avoid production interruptions in unconventional wells by separating natural gas from the fluid stream before it can enter the ESP system.

Also in December, Baker Hughes began its first field trial of its LEAP adaptive production system. The system was installed at a depth of 5,200 ft in the Mississippi Lime in Oklahoma for SandRidge Energy and delivered 300% greater oil production and 200% higher natural gas production compared to the previous artificial lift system, according to a January 2016 press release.

Borets

Borets is focused on the design, manufacture, sales and service of electric submersible pumping (ESP) systems. Headquartered in Dubai and Houston, the company operates in 24 countries. The company's new products include the continued expansion of permanent magnet motor technology. These products include bottom-driven progressing cavity pumps, high-speed ESP systems and highly efficient ESP configurations, according to the company.

In addition, Borets offers a high-temperature system capable of operating in and designed to improve runlife in the steam-assisted gravity drainage environment.

In 2015, Borets released the WR2 ESP system. This system uses a new way of manufacturing an ESP stage, a permanent magnet motor and a universal drive capable of operating both induction and permanent magnet motors. It also includes a monitoring system integrated with Borets real-time monitoring capabilities. This ESP system can be used for offshore, high-horsepower and unconventional wells.

The WR2 "wear resistant wide range" ESP system offers a new stage design and manufacturing process for extended runlife and gas production. *(Photo courtesy of Borets)*

Direct Drivehead Inc.

Founded in 2006, Direct Drivehead Inc. is most known for its Smart Pumper, a web-based SCADA system with multiple software applications for the oil, gas and water industries. It is ideal for greenfields and to control and monitor artificial lift devices like electric submersible pumps, progressive cavity pumps, tower pumps as well as control disposal systems, pipelines, tank farms and more. The Smart Pumper platform, certified and released in December 2012, interfaces with and manages variable frequency drives. It has built-in communication that works with any cell provider in any country and provides radio and 802.11 options.

DistributionNOW's half-day artificial lift workshops facilitate learning and professional discussion for its customers across the country. *(Photo courtesy of DistributionNOW)*

DistributionNOW

DistributionNOW (DNOW) offers custom rod pump systems and services, hydraulic pumping units, variable frequency drives, wellhead components, progressive cavity pumps and plunger lift equipment. DNOW's artificial lift division primarily focuses on reciprocating rod pump systems and services in the major shale plays and has 62 rod pump repair facilities in the U.S. and Canada.

With the intent to extend run times on rod pump wells and reduce failures, DNOW has organized "Best Practices for Rod Pumping Horizontal Shale Wells" workshops throughout the U.S., where operators and vendors can discuss issues and solutions.

In addition, DNOW has released its Global Pump Tracking and Services software program.

Dover Artificial Lift

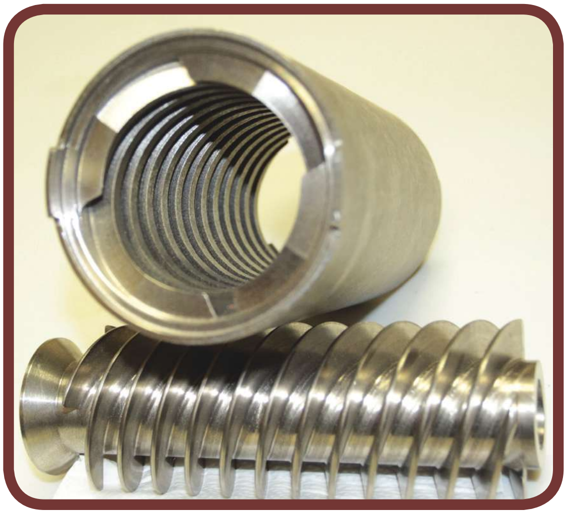
Dover Artificial Lift offers a complete suite of artificial lift products. Dover has been involved in artificial lift for 50-plus years with its Norris sucker rods and related products.

Driven largely by the unconventional shale boom in the U.S., the company has completed a number of product acquisitions. As a result, Dover Artificial Lift now offers rod lift brands such as Norris, Harbison-Fischer, Alberta Oil Tool and Upco. The company also offers progressive cavity pump systems.

Elite Multiphase Solutions

The V-Pump from Elite Multiphase Solutions (EMS) provides a technical solution for oil and gas wells in harsh producing environments. This pump is designed to eliminate the need for replacement equipment due to wear from high sand concentration, high gas volume fraction and gas slugging, which results in gas locking conditions, unpredictable production decline and repeat interventions.

The V-Pump design, which is engineered to have a wide operating range, enables uninterrupted production from a well's high initial rate to a more mature well's lower rate without having to pull and resize the electric submersible pump. The company's 538 Series V-Pump has an optimum operating range of 900 bbl/d to 5,000 bbl/d, and the 400 Series V-Pump has an optimum operating range of 200 bbl/d to 2,500 bbl/d. The pump also eliminates the need for a sand filter and tail pipe where sand is present as well as the need for gas separators.



The V-Pump is designed to handle solids, gas and heavy oil. *(Photo courtesy of Elite Multiphase Solutions)*

Extreme Telematics Corp.

Canadian engineering firm Extreme Telematics Corp. (ETC) designs and manufactures plunger lift controllers, sensors, solar panels, chemical injection controllers and general valve control products.

ETC's latest product, the Sasquatch plunger velocity sensor, was released in the U.S. in late 2015. The sensor signals the controller/remote terminal unit/SCADA system that a plunger has arrived and also provides the velocity and kinetic energy of the plunger on arrival.

In a February 2016 case study, ETC stated that one San Juan Basin producer had a well with a plunger being optimized to a target average velocity of 229 m/min (750 ft/min). After installing Sasquatch, the automation system recorded plunger surface velocities greater than 366 m/min (1,200 ft/min), which is 60% higher than the average velocity, according to the case study.

The ALiEn[2] plunger lift controller is designed to withstand extreme conditions. *(Photo courtesy of Extreme Telematics Corp.)*

Flotek

Flotek's corporate headquarters are in Houston, with the main production technology offices in Denver. The company is focused on introducing its new products in the U.S. market in the Rockies, Midcontinent and southern oil basins.

In January 2015, Flotek acquired International Artificial Lift LLC, which specializes in the design, manufacturing and service of next-generation hydraulic lifting units.

Flotek's technologies range from the proprietary Petrovalve standing and traveling valves for reciprocating pumps to patented single-well and dual-well Hydra-Lift hydraulic pumping units to a new Genius series of electric submersible pump (ESP) products and services.

GE recently released the LWM 2.0 rod pump controller. *(Image courtesy of GE Oil & Gas)*

GE Oil & Gas

GE's artificial lift portfolio includes automation, beam pumping units, completions, data management, downhole monitoring and sensors, electric submersible pumping (ESP) systems, gas lift, hydraulic pumping units, plunger lift, progressive cavity pumps, reciprocating pumps and surface pumping systems. GE recently released Lufkin Well Manager (LWM) 2.0, the next-generation rod pump controller designed to offer smarter, more efficient data-gathering capabilities and an intuitive interface. The new controller includes a full-color, user-friendly interface, complete with onboard Wi-Fi connectivity.

Global Production Solutions Inc.

Headquartered in Oklahoma, Global Production Solutions' (GPS) artificial lift products and services include electric submersible pumps (ESPs), jet pumping, well testing and repairs. In addition, the company's control and automation offerings for artificial lift include variable speed drives, motor controllers, switchboards and metering panels.

Recently, GPS developed a proprietary program to optimize water transfer and disposal costs. In testing, the company said it has reduced electric utilization by up to 50% while reducing mechanical wear.

The company's new reciprocating ESP system consists of a modified conventional ball and seat pump driven by a reciprocating downhole motor, combined with specific variable speed drive technology. This unit can be applied where flow rates are below conventional ESP systems, have a high gas-liquid ratio and high dogleg severity, and/or in horizontally completed wells where traditional rod-driven systems are inefficient and ineffective. The unit also can be applied in low-profile locations or where a small footprint is required.

Halliburton

Halliburton's artificial lift portfolio includes electric submersible pumps, surface rod pumps, progressive cavity pumps and the InteLift remote monitoring system. Each product is designed to maximize wellbore production at a variety of depths, volumes and conditions over different stages of the well life cycle.

Halliburton's REDLift XT production system is a total system concept that delivers artificial lift applications with service execution. The company's electric submersible systems—wide-range pumps, tougher motors and gas mitigation products—are designed to be reliable, efficient and durable and to

deliver better total well performance in unconventional and mature fields.

The four-step LIFTRight process defines Halliburton Artificial Lift Design of Service. First is LIFT Design, the application using the company's Simulift software application. It helps Halliburton size the necessary equipment to optimize production in a multiphase environment. Second is the LIFT Execution, which is flawless installation and commissioning of the ESP system at the wellhead. Third is LIFT Optimization, which extends uptime and runlife through the use of InteLIFT optimization. The fourth is called Lift Review, where the company combines the dismantle investigation of the equipment removed from the well and optimization data to determine how the equipment ran in the well. Then when Halliburton does the next installation, the company is able to leverage the learnings to drive the LIFTRight continuous process improvement.

John Crane

John Crane offers design, manufacturing, installation, commissioning, service and repair of rod pumps and sucker rod products for artificial lift systems.

The company provides numerous rod pumps for various applications. These include tubing pumps and rod pumps with heavy-wall barrels, tubing pumps and rod pumps with thin-wall barrels, hollow tube pumps, gas bailer pumps and self-cleaning plungers.

The company's sucker rod offerings include the Series 200 next-generation fiberglass sucker rod, corrosion-resistant fiberglass sucker rods for heavy loads and steel sucker rods that are available in a variety of grades.

The Series 200 removes stuck pumps with a one-time pull load capacity. *(Image courtesy of John Crane)*

In July 2015, John Crane released the next-generation Series 200 corrosion-resistant fiberglass sucker rods, which offer added flexibility, particularly in more challenging well conditions, according to the company. The Series 200 removes stuck pumps with a one-time pull load capacity. This line also features a predictive end fitting failure mode at the connecting pin that alleviates fiberglass splintering and broom-sticking.

Liberty Lift Solutions LLC

With more than 125 years of combined experience in the artificial lift business, Houston-based Liberty Lift Solutions provides beam pumping units, gas-lift systems and hydraulic jet pumps.

Liberty Lift also works with JJ Tech to offer hydraulic jet pump units that include a surface power fluid system, prime mover, surface pump and downhole jet pump. This provides "a solution to deviated or horizontally drilled wells at depths ranging from 1,000 ft to 18,000 ft [305 m to 5,486 m] and well production to 20,000 bbl/d, with high flowbacks of contaminated production fluids," the company said on its website.

In 2015, JJ Tech (with its design development) and Liberty Lift (with its distribution and service support) combined the Select-Jet pump with a Hydra-Cell T-series diaphragm pump from Wanner Engineering into the Ultra-Flo system. The Select-Jet pump allows the operator to run in normal or reverse flow without having to use a sliding sleeve and without having to pull the completion.

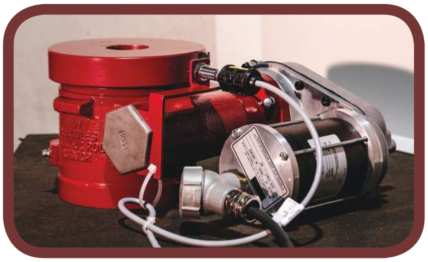
A pair of Liberty Lift HE pumping units are shown running in the Eagle Ford Shale of South Texas. *(Photo courtesy of Liberty Lift)*

National Oilwell Varco

Artificial lift technologies provided worldwide by National Oilwell Varco (NOV) under the

NOV Completion and Production Solutions segment include hydraulic rod pump systems, progressing cavity pump systems as well as production hookup equipment, tubing rotators, automation and monitoring.

NOV released its newest product, the Hercules ERR (electric rod rotator), in first-quarter 2016, The ERR is actuated using an electric motor coupled to a control system or standalone control box. By using an electric motor, the user no longer needs to install a traditional mechanical arm and cable. The new rotation sensor, coupled with the control box, monitors performance and alerts operators when failures occur.



NOV's newest product is its Hercules ERR. *(Photo courtesy of National Oilwell Varco)*

Novomet

Headquartered in Russia, Novomet has been manufacturing electric submersible pump systems (ESPs) since 2002. The company's technology includes slimline ESPs capable of fitting inside of 4-in. casing, PowerSave systems reducing power consumption by up to 50% and solutions for wells with high gas-oil ratios, scale, solids and H_2S.

The company's complete ESP offerings include downhole equipment, surface equipment as well as scale preventers and filters. Released this year, Novomet now offers a rigless cable-deployed, 2.17-in. outer diameter ESP system designed to fit inside of $2\frac{5}{8}$-in. tubing. This ESP system was designed to reduce operation costs for oil and water production.

Priority Artificial Lift Systems LLC

Priority Artificial Lift Systems, a division of Priority Energy Holdings LLC, manufactures a complete line

Schlumberger offers artificial lift products capable of handling a variety of flow rates in both mild and extreme environments. (Image courtesy of Schlumberger)

of gas-lift valves, mandrels, plunger lift and downhole equipment. In addition to the Houston-based company's artificial lift product lines, it also provides packer and completion tools and offers service and installation along with production optimization, production analysis and well modeling.

Priority can manufacture any size gas-lift or plunger-lift equipment with any material for worldwide distribution.

In November 2015, the company released its INSTEP lubricator. The multipurpose lubricator is the control center of the plunger-lift system. It manipulates the operation of the plunger by means of a catch using inputs from manual operation or an automatic controller. It harnesses the energy of a returning plunger and diverts sales fluids/gases to production storage facilities. It was tested as working up to 3,000 psi. The company is increasing its focus on production and optimization products in 2016. In January 2016, the company released its new Free Cycle Plunger, which is designed for gas-lift assist (e.g., to cut paraffin).

Schlumberger

Schlumberger offers a variety of artificial lift products that include electric submersible pumps (ESPs), a rigless ESP replacement system, gas lift, horizontal surface pumps, surface electrical equipment and services, sucker rod pumping, production lifting services and progressive cavity pumps (PCPs).

Schlumberger's ESP systems include the REDA Maximus ESP system, REDA Continuum unconventional extended-life ESP, REDA Hotline high-temperature ESP system, REDA Coil coiled-tubing-deployed ESP system, EZLine low-temperature ESP system, MaxFORTE high-reliability ESP system as well as ESP system components. Schlumberger also offers the DesignRite artificial lift design and optimization software, LiftPro well optimization service and LiftWatcher real-time surveillance service.

The company's Maximus system, released in 2010, uses exclusive ESP flange connection technology for simpler and more reliable mechanical connections of motors and protectors, according to the company's website. The system features an ESP quick-plug motor lead extension that ensures a leak-tight connection and eliminates the process of taping in the pothead terminals at the well site. Variable-rated for different operating conditions, Maximus system motors offer flexibility across all ESP wells and applications, including severe weather conditions. Maximus system protector heads feature the same abrasion-resistant bearing system successfully implemented in REDA ESP systems for more than 15 years. Cameron, a Schlumberger company, offers sucker rods and progressive cavity pumps.

The Datalogger-4200 is a high-performance surface monitoring and automation system designed to interface with Sercel-GRC's digital downhole sensors. *(Photo courtesy of Sercel-GRC)*

Sercel-GRC

Sercel-GRC provides downhole pressure/temperature gauges to artificial lift and permanent monitoring markets worldwide. The company's artificial lift products service electric submersible pump (ESP), progressive cavity pump (PCP), gas-lift, sucker-rod pump and jet pump applications.

Sercel-GRC recently released its Spy Pro ESP gauge with uCommand technology. Spy Pro features a waterproof connection design. The gauge also offers 11 channels of sensor data, including a well fluid ingress measurement that might indicate pending ESP motor failures.

The Spy Pro ESP gauge is compatible with all ESP providers, including slimhole applications with a 3.75-in. equipment diameter. The Spy Pro product family includes multiple configuration options, including corrosion-resistant metallurgy, various motor adapters and discharge pressure measurement.

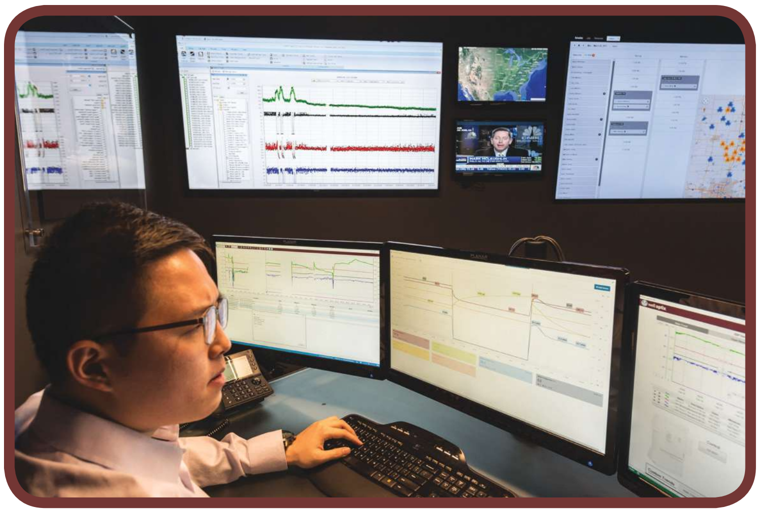
Summit ESP

Summit ESP provides electric submersible pumping systems (ESPs) and surface pumping systems as well as a variety of products and services to meet ESP needs. The company offers extended range pumps, advanced gas handling, abrasion-resistant technology, harmonic mitigation and high-performance motors.

In April 2015, the company completed its 4,000th ESP installation in the Permian Basin, and in October 2015, the company completed its 5,000th installation, this time in North Dakota.

In July 2015, Summit ESP released its Sentry Well Surveillance & Optimization Services, which is backed with in-person monitoring services. Sentry collects data from artificial lift operations and then provides operators with critical information necessary to optimize production and minimize field downtime. The company's Sentry surveillance team continuously monitors an operator's production from its monitoring center in Tulsa. The surveillance team has access to a complete 360-degree view of every well's operational information, downhole equipment, application design and field service history.

Summit ESP's Sentry Well Surveillance & Optimization Services are backed with in-person monitoring services. *(Photo courtesy of Summit ESP)*



Superior Energy Services

Superior Energy provides fit-for-purpose artificial lift products, and Superior's Gas Lift division includes onshore and offshore gas-lift equipment.

Superior offers gas-lift design, troubleshooting and optimization classes in the field and in the office for engineers, pumpers and interns. The company's manufacturing facility, located in Belle Chasse, La., manufactures conventional and retrievable equipment including conventional injection pressure operated (IPO) valves, retrievable IPO valves, reverse flow check valves, retrievable latches, orifice valves, dummy valves and more.

The gas-lift group works alongside IPS, a Superior Energy Services Co., to offer plunger lift as well as gas-lift-assisted plunger-lift systems. IPS provides an assortment of plungers including a single-pad, dual-pad, brush, spiral, spiral with rifling and the Pacemaker plunger. The Pacemaker plunger is designed to eliminate the need for any shut-in time, to remove more wellbore fluid by making more trips per day, and it has the ability to fall in the well against flow, according to the company.

Tenaris is a supplier of premium sucker rods and related services for the energy industry. *(Photo courtesy of Tenaris)*

Tenaris

Tenaris, a supplier of premium sucker rods and related services, has production facilities in Argentina, Brazil, Mexico and Romania. A new U.S. mill is under construction in Conroe, Texas, that will bring the company's global production capacity to more than 4 million units (30.4 million meters [100 million feet]) once completed.

Tenaris offers two new technologies: the BlueRod premium sucker rods and the HolloRod Series. BlueRod technology addresses beam pumping failures related to high loading by providing a connection with the same loading capacity as the rod body.

The HolloRod Series consists of hollow sucker rods developed by the company's R&D team to increase the reliability of progressive cavity pump operations and offer an alternative to unconventional beam pumping applications.

The HolloRod sucker rods decrease premature failures due to rod pin breakage caused by over torqueing during well operations and have fewer tubing wear failures. They also reduce backspin effect and handling problems because installation does not require special tools.

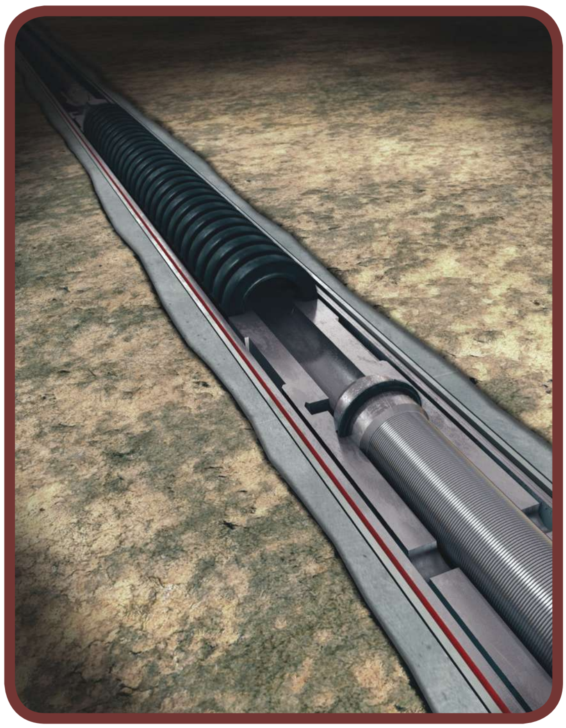
Unico

Unico Inc. provides variable frequency drives and controls for electric submersible pumps, hydraulic pumping units, progressive cavity pumps (PCPs) and sucker rod pumps. The company's mechanical lift systems include its LRP linear rod pumps, PCPs, CRP crank rod pumps and HAP hydraulically actuated pumps. The company also offers pump controllers and remote monitoring.

In 2015, Unico released its Pump Clean algorithm, which is installed within the company's LRP units to clear debris from pumps. Pump Clean vibrates the pump at strategic frequencies for about two minutes to dislodge debris. This is accomplished entirely with software, not requiring any additional hardware or equipment beyond a standard LRP unit itself. It can be executed in one of three ways: remotely (through telemetry), at the drive keypad or automatically.

Weatherford

Weatherford, which offers multiple forms of artificial lift, designs optimized artificial lift systems



The STP is an alternative to standard rod pumps in wells with high sand production and temperatures up to 182 C. *(Image courtesy of Weatherford)* according to a systematic optimization cycle to proactively increase production and reduce costs. The company's lift systems include reciprocating rod lift, capillary injection, gas lift, jet-pump lift, hydraulic piston-pump lift, plunger lift and progressing cavity pump (PCP) lift. Weatherford also provides electronics, sensors, software and consultants for production optimization.

In September 2015, Weatherford released its sand-tolerant pump (STP), an alternative to standard rod pumps in wells with high sand production. The STP can perform in temperatures up to 182 C (360 F) and has a self-cleaning filter to keep damaging sand out of the plunger-barrel sealing surfaces.

In November 2015, Weatherford released its Production Optimization Consulting services, which provide optimization solutions to enable proactive well, reservoir and asset management. After comprehensive analysis of the well or field, consultants recommend the most suitable artificial lift systems, surface and downhole sensors, controllers, production optimization software and workflows appropriate to the assets.

Zedi Inc.

Zedi is an oil and gas technology and services company that offers automation, artificial lift, field instrumentation and data management technology as well as consulting, field and support services.

The Zedi SilverJack artificial lift system is an advanced hydraulic pumpjack with a local graphics-based optimization controller and Zedi Access web-based data management system that provides remote monitoring, alarming and control. This allows both local and remote optimization and the resolution of common rod pumping problems without site visits or labor-intensive manual processes.

Released in November 2015, the SilverJack 8000 includes the same controller, data management system and optimization capabilities as the SilverJack 6000 with the addition of nitrogen gas assisted lift. The SilverJack 8000 has double the capacity of the SilverJack 6000 (up to 45,000 lb rodstring weight and 240 in. [6 m] of stroke length). ■

The SilverJack 8000 has double the capacity of the SilverJack 6000 (up to 45,000 lb rodstring weight and 240 in. [6 m] of stroke length). *(Photo courtesy of Zedi)*

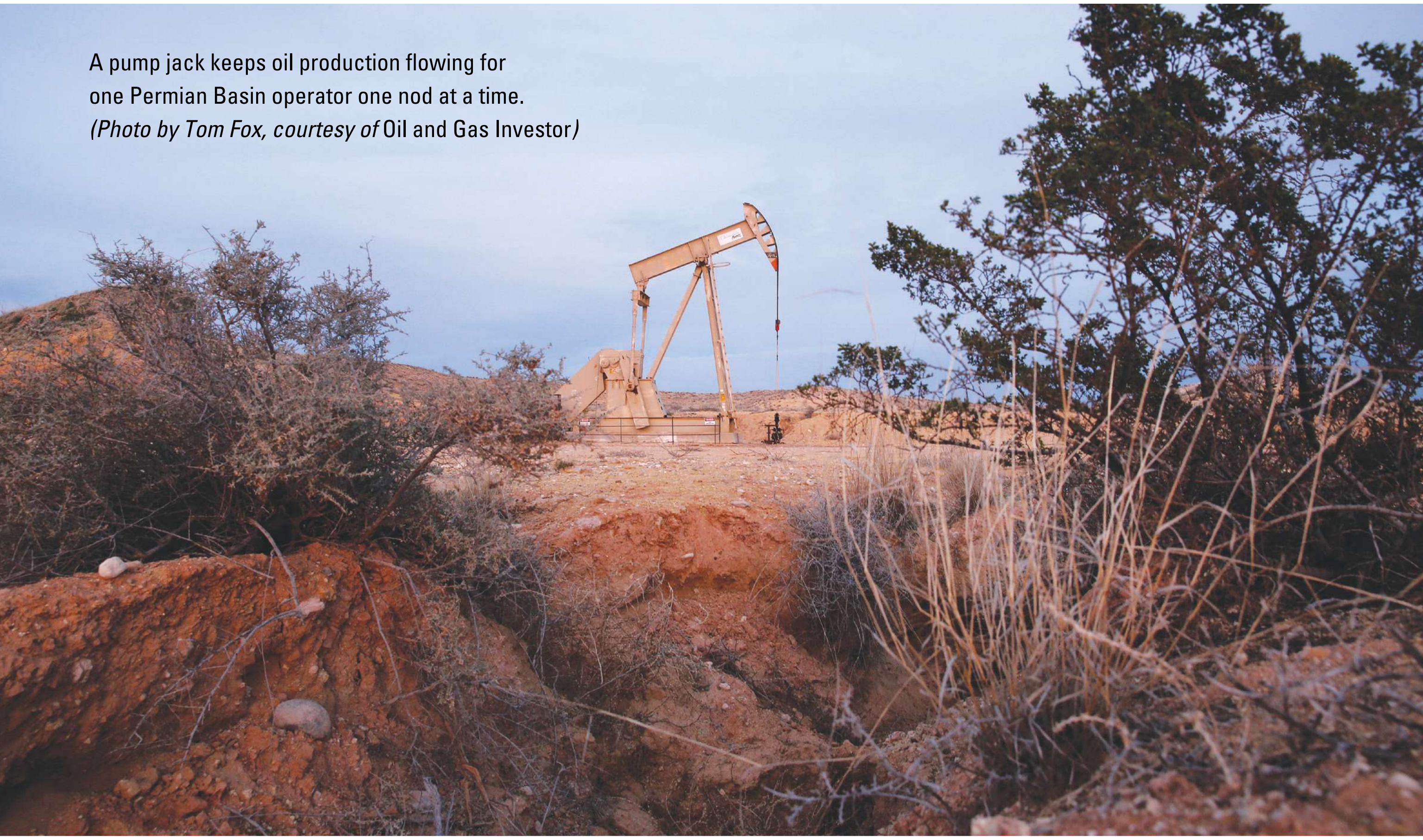
An Unconventional Look at Artificial Lift

Providers look to collaboration and new technologies to keep production flowing in unconventional wells.

By Jennifer Presley
Senior Editor, Production Technologies

Lower oil prices and cost reduction pressures have prompted operators, service companies and equipment manufacturers to develop new technologies and approaches in artificial lift that are more efficient, reliable and robust. All are qualities that can help deliver lower initial and operating costs to battered budgets. Accomplishing this task is no easy feat, especially for those working in the North American shale plays.

The steep learning curve that unconventional plays presented over the last decade required drillers to learn fast and adapt quickly to find success. For example, longer laterals contacted more of the reservoir. Multiple wells on a single pad lead to



A pump jack keeps oil production flowing for one Permian Basin operator one nod at a time. *(Photo by Tom Fox, courtesy of* Oil and Gas Investor*)*

increased drilling efficiencies. More sand downhole helps prop fractures open for longer.

However, those improvements delivered a new set of challenges for production teams to manage in the remaining years of a well's life.

In a fashion similar to the one patterned by drilling and completions teams, the technologies and techniques used by production teams are also evolving. Earlier and more open communication between the teams paired with new or improved technologies for challenges like sand is expanding artificial lift applications considerably.

Early planning

In the beginning of what would become known as the "shale gale," it was common to hear tales of wells coming in with staggeringly high rates of flow. Also common was the bark of the naysayer pointing out the rapid drop-off of production shortly after the well was brought online. Like an agitated bottle of champagne, once its cork was popped and its bubbles bubbled out, unconventional wells were left needing a lift option far earlier in life.

"In conventional production from vertical wells the production declines gradually over time such that lift selection can be delayed and the best lift to use is usually fairly obvious. Also, the well geometry is fairly uniform and easy to work with," said Bill Lane, vice president of emerging technologies for artificial lift systems at Weatherford.

"However, in unconventional production, lift selection is more challenging. Production rates can be highly variable and are characterized by slugging of gas and liquids. Lift systems must be able to handle significant amounts of gas, including long gas slugs. Hydraulic fracturing of low-permeability shale results in high initial production rates followed by a rapid decline in production. Therefore, lift systems must either be flexible and capable of operating efficiently over a wide range of production rates, or lift systems must be easily resized or replaced.

"All of that needs to be considered upfront, during the well-planning stage, rather than as an afterthought. The wells can require artificial lift within three to six months of initial well production, sometimes even sooner," he said. "It usually makes sense to go ahead and have the artificial lift system in place, rather than having to come back on the well within a few months of the commissioning."

The need for earlier involvement in field development planning was seconded by Neil Griffiths, business development manager for artificial lift technologies for Schlumberger.

"Wells must be designed, drilled and completed with their life cycle of free flow production and inevitable artificial lift in mind. Often this is not the case," he said. "All field development plans should include artificial lift considerations and, wherever possible, the wells should be designed from 'inside out' to accommodate them—first the ideal completion and then casing design. Again this is often not the case," he said.

"Typical shortcomings and compromises include casing or liner size and wellbore trajectory. The old adage of 'drillers and well engineers have love affairs with wells, whereas production engineers are married for life' is as true now as it ever was. Examples include 7-in. and smaller casings limiting artificial lift selection, where 7-5/8-in. casing would offer so much more opportunity," he said.

"Also wells drilled too quickly result in tortuous wellbores that cause problems with pump operations throughout well life, for example, rod or tubing wear, pump or cable damage, bent shafts, and reduced run life."

Building straight

According to Lane, deep unconventional wells often require long artificial lift pumps that are incompatible with high deviation build rates, adding that some operators are building in straight tangent sections within the build section in order to have a straight section in which to land the lift pump.

The formation of multidisciplinary teams to tackle tough challenges has become more common as the need for collaboration across disciplines has become more accepted within the industry. That approach can help influence how wells are constructed to result in greater recovery, according to Jonathan Nichols, unconventional market segment manager for Baker Hughes.

"ESP systems have to operate in a relatively straight area, but the deeper you can get in the well and the closer you can get to the producing zone the more reservoir pressure draw is going to be achieved, resulting in greater production in reserve recovery," said Nichols.

"By working with multidisciplinary teams, we are able to influence the well design including, creating an ESP-friendly tangent in the curve section and the size of the completion of the unconventional wells.

"Ultimately what we're trying to do in that ESP-friendly zone—in that curve section—is create a spot where you have a lesser deviation or you have lesser dog legs. That allows us to reduce the torsional stress on the equipment which is going to result in greater reliability in production. For example, our CENesis CURVE system is designed to get through up to a 25-degree per 100 ft deviation, which allows us to get closer to the producing reservoir," he said.

Selection, design considerations

For Halliburton, delivering reliable lift application with flawless execution at the lowest total cost to the customer through the use of ESPs in high gas, high sand environments is a primary focus, according to Chuck Ervin, vice president of artificial lift.

"LIFTRight defines Halliburton artificial lift design of service. First is LIFT Design, the application using our Simulift software application. It helps us size the necessary equipment to optimized production in an multiphase environment. Second, is LIFT Execution, flawless installation and commissioning of the ESP system at the wellhead and the third is LIFT Optimization, extending uptime and run life through the use of InteLIFT automation," he said.

"The fourth—LIFT Review—is where we combine the dismantle investigation of the equipment removed from the well with optimization data to determine how the equipment ran in the well so that when we do the next installation, we're able to leverage the learnings to drive the LIFT Right continuous process improvement."

While unconventional wells do present rapidly changing conditions and significant production of solids and abrasives, the selection of an appropriate artificial lift system is no different from any other well, according to Schlumberger's Griffiths.

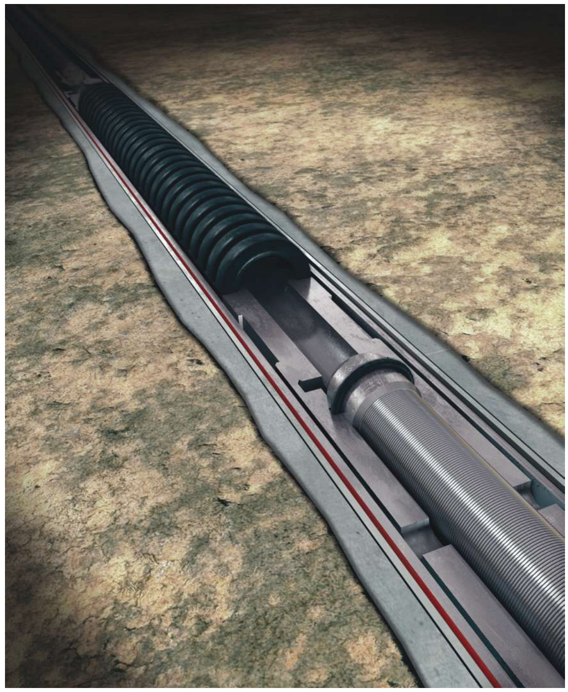
"A diligent artificial lift engineer will ensure that the right artificial lift system is deployed in the right well at the right time by adopting a production system life cycle value perspective. Life cycle value may be defined as life cycle revenue, from ultimate recovery, minus the total cost of ownership phased/discounted over the life cycle," he said.

"This may sometimes conflict with short-term production targets particularly in times of industry downturn. To evaluate the life cycle value of the various options, the artificial lift engineer must determine and respect the numerous constraints on the well and/or the production system. Some constraints may be related to flow rate, some to drawdown, and some may be nontechnical in nature. The prevailing constraint will change with time. Only when these matters are considered and continually reassessed will the selection and design of artificial lift system be optimum."

In addition to the numerous design constraints, there are other factors to consider in the design process, said Mike Berry, an independent petroleum engineer.

"These wells have such a rapid drawdown. For example, you'll start off with a jet pump or an ESP [electric submersible pump] and you'll get a high production rate early in the life of a well," he said. "But then the well drops off so fast that if you are using an ESP, you're going to drop below the design rate of the ESP before it should, theoretically, meet its end of life. You're going to have to either change to a smaller ESP or go to something like a rod pump. You end up installing two different infrastructures.

"You need to think ahead of time what facilities are going to be needed and then ask if it is really necessary to build multiple infrastructures. You should determine if you can live with the lower rate until you get down to something you can handle with just a single lift system," Berry said. "While time is money and it is critical to get that maximum rate right away, you need to determine how much of an economic gain are you losing by having to put in and learn how to use multiple lift systems?"



By utilizing a unique wiper and filter coupling assembly, the STP helps reduce damage caused by sand to the barrel/plunger interface in reciprocating pumps. *(Image courtesy of Weatherford)*

Sandy challenges

Long a nemesis to pumps and motors, the abundance of sand and proppants used in unconventional wells has added another dimension to the common challenge of wear and erosion. Gas lift, jet pumps, ESP and rod pump systems are commonly applied in unconventional wells.

"A gas lift system can handle sand and any kind of debris. Sand will pretty much kill a pump. When putting a well on a pumping unit, if the well's not cleaned up enough, you'll have sand issues with your downhole rod pump as well," said Kelly Raper, vice president of sales and corporate development for Priority Energy Services. "Gas lift, although in many cases can't produce the fluid that an ESP can, we can obviously produce various rates, from very high rates to very low rates, so gas lift is probably the most economical way to look at doing this because we can vary so much in the different rates."

However, there are critical questions to consider before going with a gas lift system.

"These wells are, for the most part, hard on artificial lift, because they've got a lot of gas. You immediately say, 'well, we need to put them on gas lift, we've already got a lot of gas' but you have to have an injection gas supply from somewhere," said Berry. "Compression can be expensive if a high-pressure gas well is not available to supply the gas for gas lift. Maybe you want to forget about the gas lift and maybe even the ESPs and just pump what you can with the rod pump? You lose a little triangle of potential production, but you don't have to run this huge power system for an ESP or gas lines for a gas lift system. You need to run the economics to see if it will pay out."

For jet pumps, ESPs and rod lift systems, advancements in technology and materials are helping each to be more robust in design and in applications.

"Unconventional production has caused us to rethink which tools were used for initial production," said Weatherford's Lane. "For example, the first fluids that must be removed are the frack flowback fluids. Typically they're full of particulate matter, frack sand and produced sand. Jet pumps are very effective at removing these materials, and so jet pumps have become a leading technology for cleaning up wells. They can then be used for initial high production rates before transitioning to other types of artificial lift."

In addition to cleaning up wells during flowback, jet pumps have been used to get production flowing again. A South Texas operator contacted Dover Artificial Lift to get a well back online that was damaged due to a "frack hit" from an adjacent well workover without a large opex cost, according to a company-issued press release. The solution used a 1.25 in. jet pump installed inside the existing 2.875-in. production tubing just above the lateral. Power fluid was pumped down the integral joint tubing to the jet pump, where it combined with the formation fluid to exit the jet and travel back to the surface through the created annulus. The revived well generates $250,000 worth of production per month, according to the company. Costs were reduced overall to the operator, with produced natural gas being used to power the power fluid pumping unit with no additional costs.

For Charlie Fowler, vice president of technology for Dover Artificial Lift, there are three ways to deal with sand, and recent advances in new products demonstrate that approach.

"One is to eliminate as much as possible through separation before it enters the pump. Another is to use materials in the pump that are harder than the sand. The third is to optimize the geometry of the pump so that the sand passes right through it with minimal effect," Fowler said.

For wells on rod pumps, the accumulation of sand can cause significant abrasion to the barrel/plunger.

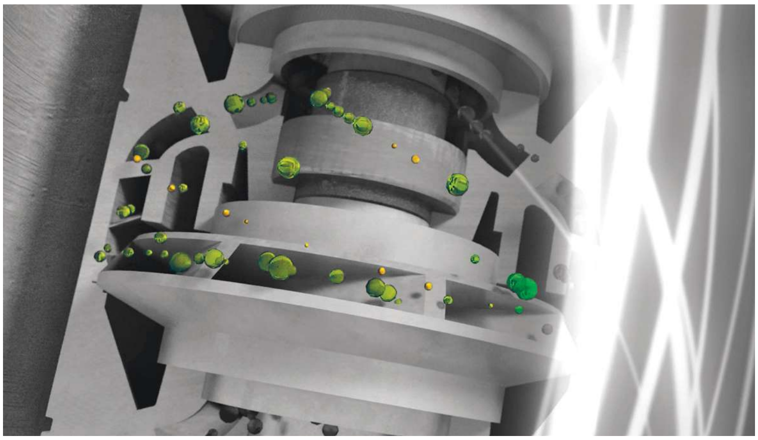
"Producing sandy fluids has been a problem in both conventional and unconventional production. Weatherford now offers a sand tolerant pump [STP], which is the first rod pump to dramatically improve pump run life in very sandy environments. The STP represents a paradigm shift in pumping technology," said Lane.

The company released its STP onto the market in 2015 although it had been in field tests since 2012. The STP prevents abrasion caused by sand accumulation in the barrel/plunger sealing areas by filtering the fluid film between the barrel and plunger. The filter screen is designed to prevent sand buildup on the screen, and the pumping action washes the screen clean on each downstroke. A pressure-balanced wiper assembly and filter coupling creates a barrier to prevent sand from falling back into the pump-sealing areas.

For wells equipped with an ESP, frack sand and other solids can lead to severe erosion and wear. In addition, sand accumulation, plugging or contamination can also wreck havoc on a well.

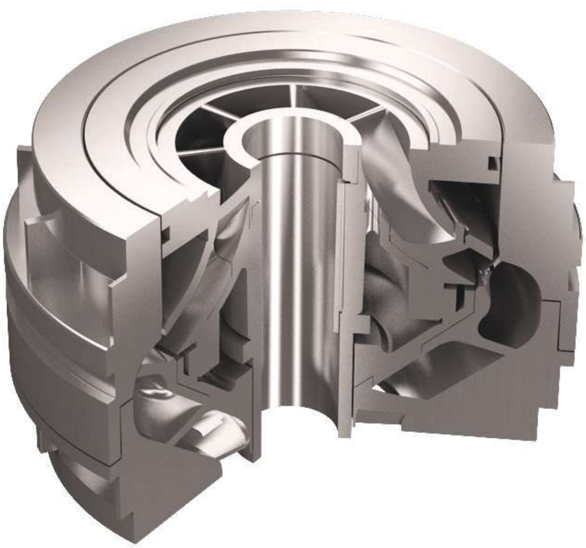
"Though it could reasonably be argued that the majority of failures are unnecessary, the failure modes of artificial lift systems, and particularly of pumps and ESPs, are varied. Consequently, there are numerous initiatives to increase system run life," Griffiths said. "The Schlumberger MaxFORTE high-reliability ESP system is aimed to increase run life tenfold by paying meticulous attention to detail at every stage of the system life cycle from design through manufacturing, QA/QC, and installation to surveillance and optimization."

The approach to understanding wear and tear on pumps is built on collaboration, analysis and material science.



The high-performance FLEXPump series pumps are specifically designed to maximize production and ultimate reserve recovery from unconventional resource plays in which the production index declines rapidly. (Image courtesy of Baker Hughes)

"We take a two-pronged approach to addressing abrasives the pump–erosive and abrasive resistant enhancements. The first step, however, is to perform what we call a sand analysis, where the abrasive is characterized with five different metrics, and based upon that, we can then recommend the best solution," said Lawrence Burleigh, technical support director, artificial lift systems for Baker Hughes.



Components for the WR2 ESP system are manufactured through metal-injection molding, allowing engineers to use geometries in design that cannot be economically produced in a foundry. *(Image courtesy of Borets)*

"From the erosive perspective, different geometries in the pump can minimize the effective velocity of the sand and the impact of the sand on the vane surfaces. When designing the FLEXPump series pump line, the hydraulics and vane geometries were optimized to minimize erosive wear. The sand will pass through the pump more easily due to wider vane openings and more direct hydraulic path. Coating the stages also minimizes erosive wear. As far as the abrasive wear, various carbide bearings that have a hardness greater than quartz can be selected," he said.

Another product tackling the challenge of frack sand flowback is Borets' new ESP system that uses a unique material and process to produce a new stage that resists abrasive wear in most wells by the geometry of the stage, the materials and the manufacturing process. The Wide Range Resistant (WR2) ESP system is suited for harsh well conditions and has the ability to handle a wide range of production, abrasives and gas, according to the company.

The WR2 stage material is stronger and harder than traditional ESP stage materials on the micro level which allows it to resist erosion from sand and proppant. The WR2 stage material has a hardness rating near that of ceramic bearings and a hardness close to quartz, according to the company. The special construction allows for unique vane geometry that helps prevent gas locking and provides efficient operation at high RPM.

The future of lift

With Big Data playing a much greater role in day-to-day operations, artificial lift systems have and will continue to adapt and evolve to bring greater efficiencies and production at lower costs.

"In terms of artificial lift overall, what we're seeing is just the envelope being stretched. There are currently no dramatically new types of artificial lift. However, we're seeing lift systems produce fluids from deeper, or produce at higher rates or in higher temperatures," Lane said.

As Richard Spears noted in his market overview, proximity to urban living centers and the technical need for long-stroke rod lift systems are driving operators to new technologies.

Liberty Lift Solutions introduced its XL model long -stroke rod pumping unit in early 2016. The product incorporates numerous features designed to promote extended life, operational advantages, energy efficiency and minimal maintenance.

The XL unit has a size designation of 320-500-306 and operates at slow speeds with constant velocity, providing fewer strokes per minute with high production rates, according to the company.

"The thought process in rod pumping has always been long, slow strokes; the longer the stroke, the slower you can go. The XL model has a 306-in. stroke, with a top end speed on this unit at about 4.3 strokes per minute," said Don Crow, vice president of sales for the company. "This allows horizontal wells to pump at slower speeds, typically resulting in less rod wear and more fluid produced with the longer stroke."

The pumping unit incorporates an efficient, clean oiling system for internal parts, according to the company. The unit was designed with easy access in mind for maintenance as the system incorporates safety features to protect operating personnel and the environment. For example, the unit's integrated rollback system allows easy movement and repositioning for safer workover operations.

Well intervention is another area where significant advances have been made.

"Though it may be claimed that surveillance and optimization have improved over the years, the only real step change in the last decade is the introduction of alternatively deployed "rigless" ESP systems," said Schlumberger's Griffiths.

"The ZEiTECS Shuttle rigless ESP replacement system from Schlumberger, for example, allows ESPs to be replaced on wireline, coiled tubing or rods without a rig. This minimizes production deferment, operating cost and disruption to operations while significantly reducing HSE exposure and risk. The alternatively deployed ESP technologies mitigate risk and improve the customer value proposition of standard ESPs."

So what could the artificial lift technologies look like in the future?

"I think we'll see some hybrid solutions," said Ron Holsey, digital commercial leader for GE Oil and Gas Surface business. "For example, one of the weak points of a pumping unit today is actually just the physical rod. If you can still do a reciprocating pump downhole that is rodless, I think that is something you may see sooner rather than later. It is a real possibility because you eliminate the one major point of failure within that system.

The ZEiTECS Shuttle allows standard ESP interventions without a rig. *(Image courtesy of Schlumberger)*

"You'll see some evolution to systems that can handle the in-between. When we punch a hole in the ground—once we get the initial production—we ride that initial decline curve, then we start making decisions on how to artificially lift it. You talk to the ESP guys, and they can do down to 20 barrels a day, but it's not very efficient. I think what you will see that technology will start to fill those gray areas a little bit more—rod pump systems able to bleed more into where the initial ESP business is and you'll see ESPs bleed into where the rod pump is today."

The need for automation will continue to increase as the demand for more data to better optimize production increases.

"In addition to how much fluid we move, probably more important, is how we can help customers manage their production in the field. It is going to be at the enterprise-wide level and at the field-wide level optimization and we also will see tighter integration between what's in the reservoir and what's in the production system," Holsey said. "Those two areas are pretty much walled off today for what, I would say, are not very good reasons other than that's just the way it's always been. The advent of being able to take real time-data and do real-time production optimization based off the reservoir data is where we will be going to in the future." ■

Automation Leads to Optimization

The digital oil field is overtaking artificial lift, and the industry is a better place because of it.

By Rhonda Duey
Executive Editor

The evolution of automation in the oil field has been an interesting one to watch. Artificial lift methods have been around for decades, but only recently have operators begun to adopt the types of technologies that truly help optimize their production.

"Starting out, switchboards were used for sub-pumps," said Stewart Reed, Ph.D., artificial lift engineering discipline manager for Halliburton. "A switchboard is just a switch—it's either on or off. There is no mechanism to speed up, slow down or respond to any kind of dynamic event.

"It's a dumb device, but a lot of fluid was produced using that technology."

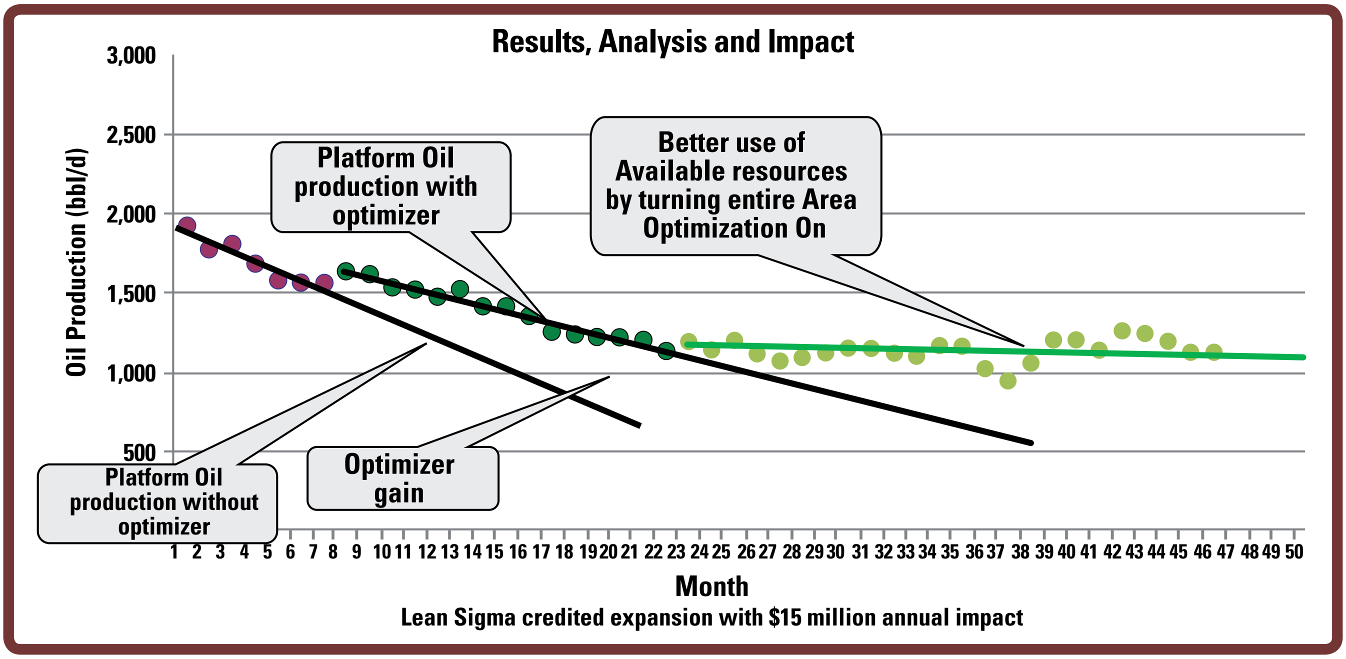
Variable speed drives (VSDs) have since entered the fray, and with systems like electric submersible pumps (ESPs) that can be dramatically affected by gas slugs or solids events, these drives have the potential to provide a second step change, Reed said.

Automation and improved technology result in increased production, uptime and runlife. *(Photo courtesy of Schlumberger)*

VSDs have now been in use for ESP operation for many years, but it's taken operators a while to catch on to their true utility, he said. "Real automation is there if we choose to use it, but our culture needs to keep evolving so that we continue going down a more refined path," he said. The initial benefits of VSDs were soft starting, the ability to change the pump's operating speed during operation and automatic fault protection. Now there is a movement to actually use the more sophisticated abilities of the VSD, mainly dynamic control to respond to spontaneous load changes. "Most advanced usage of VSDs in the recent past were, at best, dabbles in the industry," Reed said. "What we are now experiencing is an undeniable universal need and awareness brought on mostly by the dynamics common to unconventional wells."

Older fields are less likely to require enhanced automation, he added, but unconventional wells need all of the bells and whistles. "These are the most challenging wells we've seen for artificial lift," he said, adding that the presence of unpredictable dynamic events can wreak havoc on an ESP if it's not optimized using sound methodologies and a total system approach.

"You can have phenomena like gas locking, which causes immediate heating problems throughout the entire ESP string, not just the motor," he said. "You have to plan for dynamic events and rapid well changes. Expectations for responsiveness and timely communications need to be established



Real client data demonstrate that fully employing automation and optimization technologies can almost flatten decline curves. *(Data courtesy of Emerson)*

prior to any install. ESP application designs should be interrelated with a thought-through control strategy. The customer's ground-level desires and abilities must be incorporated into the design and the control strategy." Halliburton has used this approach to more than double average run times where more conventional strategies were failing.

Better control, better data

The move to automation is resulting in operators and service companies having much more remote control over their fields. Steve Seale, director of software and automation at Weatherford, described the basic "digital oilfield" setup.

"We kind of view the structure for the digital oil field in three different layers," he said. "One, you have a set of equipment at the well site that's collecting real-time information and doing control. Depending on the artificial lift technique employed, it's going to have a different set of equipment.

"That information feeds into the customer's SCADA system, and meanwhile the customer is doing management of the field, managing downtime, trying to keep the wells operational, etc., in some type of data center."

Weatherford has a set of lift optimization modules that couple the real-time data and allow the engineers to do nodal analysis with the information, he added. This is referred to the "analysis workbench," and the company has a different workbench for each type of lift. Seale said that the analytics space is really twofold, involving not only an engineering perspective but an IT perspective in terms of predicting well behavior.

On top of this is an asset management view of things, more of a business perspective for managing the asset. This is managed through Weatherford's Intelligent Daily Operations.

"By the time it gets to the desktop, there's typically some type of human interaction to analyze the situation," he said. "But more and more analytics are being pushed out to the controller or the field devices. Even the well models, techniques that traditionally have been done with a desktop nodal analysis tool, are being pushed to the controller."

Rod pumps

Rod pumps are probably the most widely used form of artificial lift and are benefitting from the new technologies. Seale said that some operators have saved up to $6 million a year by optimizing their rod pump operations. This is partly being driven by the use of variable frequency drives (VFDs).

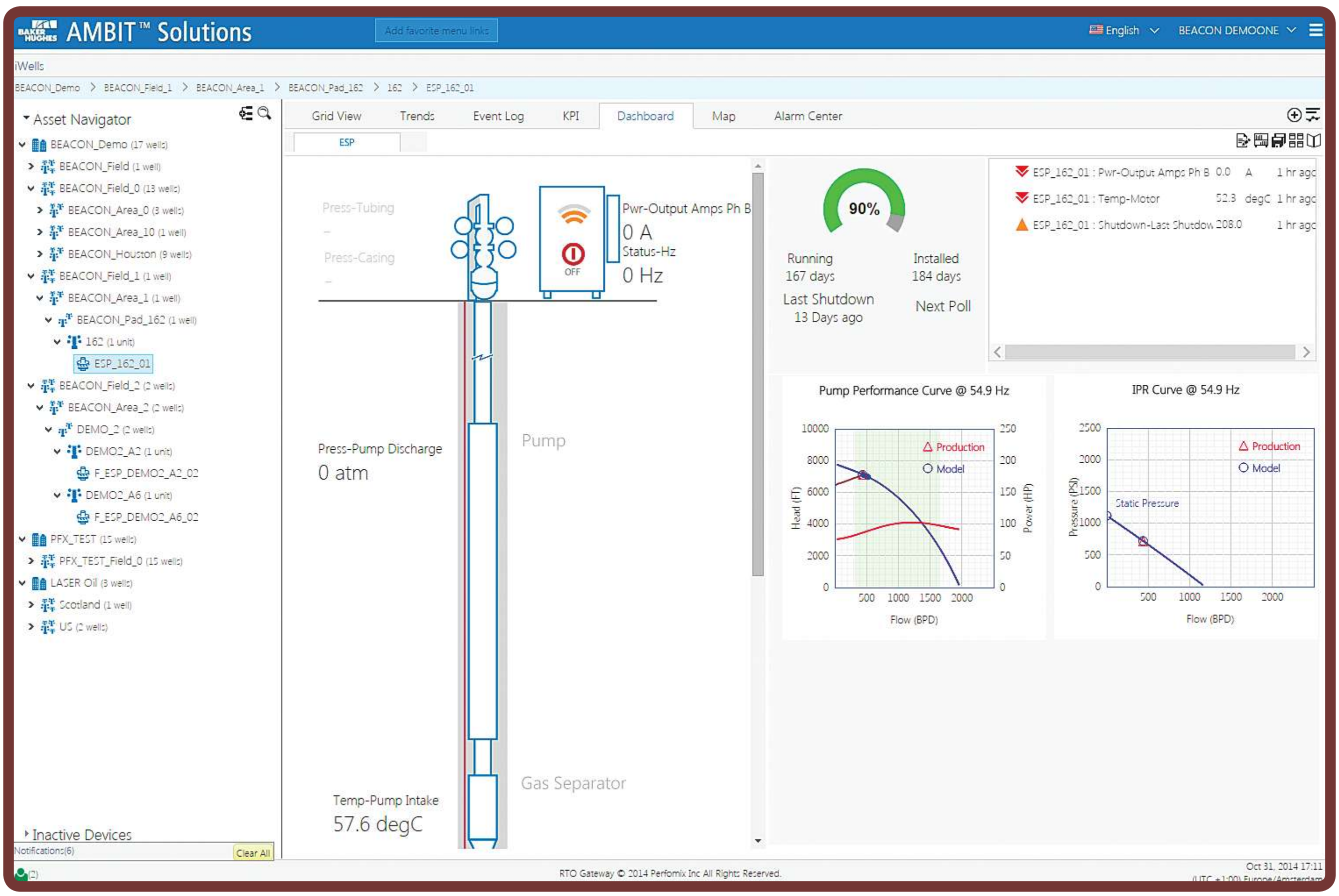
SPOC Automation offers VFD technology to help operators save electricity and eliminate penalties at the well site. In a recent presentation, John Smith of SPOC outlined the benefits of this technology, which include the ability to use NEMA B motors on the pumps, which save about 3% to 5% in energy costs, and the elimination of regeneration. Smith explained that when the heavier side of the beam is moving down, it actually generates energy, but operators don't get credit from the utilities for this.

"We talk about optimization, but there are all different forms," Seale said. "There's improved control at the wellhead, there's optimizing electricity usage, there's optimizing uptime of the wells, there's optimizing delivery for the oil or gas contract—almost every area you can think of can be optimized." Even people can be optimized since these types of automation require fewer visits to the well site, he said. "You can do it all remotely, even having video or camera images at the well site. You can monitor everything remotely no matter where it is."

Schlumberger's automation technology can be used on a variety of lift systems, according to Rajkumar S. Mathiravedu, marketing and technology manager for Schlumberger Lift Solutions. "Our UniStar downhole protection VSD automation solutions utilize sophisticated algorithms to provide real-time control and diagnostics of rod-pumped wells," Mathiravedu said. "A variety of control parameters can be employed to protect surface and downhole equipment, providing flexibility for our clients to program and select parameters to meet their desired optimization strategy."

ESPs

While rod pumps are widely used, Reed said that ESPs are arguably "the number one method of artificial lift," primarily due to the ability of providing range and volume, a necessity in the unconventional market. Halliburton brings a strategy to bear on optimizing ESPs in unconventional plays.



The Baker Hughes AMBIT system allows ESPs to dynamically respond to downhole situations. *(Image courtesy of Baker Hughes)*

"At the meat of it, we're very sincere about developing a working relationship with our customers," he said. "Optimization is going to work best when you develop a strong customer affiliation and you team up to produce their assets. If you don't work together, you're not going to achieve the results desired, and that in essence is driven by the nature of an unconventional well. It takes a true team effort and vendor-customer partnership to not just succeed with unconventional wells but to deliver a thriving solution."

Halliburton has responded to the evolving times with LIFTRight, a design of service process that harnesses the customer relationship while employing proprietary tools, processes and updated methodologies to elevate ESP applications. LIFTRight incorporates four key elements: design, service execution, monitoring and optimization, and review. Linking these elements is a multidisciplined team that works in step with the customer to expedite utilization of the immense amounts of data that already are available along with technologies that already have been introduced or will be available in the near future. LIFTRight is designed to help maintain fiscal practicality by providing the lowest cost product.

Baker Hughes has created a production monitoring and optimization platform called AMBIT solutions with ESPs in mind. According to Tommy Denney, product line manager for the company's Production Decision Services, ESPs don't inherently present challenges, but their applications do. Reliability improvements over the past 20 years have made them the system of choice in more complex environments such as high-temperature conditions, subsea wells and unconventionals.

"To extend the runlife of the ESP, increase fluid production and minimize deferred production and downtime, advanced automation, surveillance and continuous optimization of the ESP is recommended," Denney said.

AMBIT ESP monitoring services come as a tiered offering, where the base level system allows users to visualize all of their ESP data in an intuitive web interface, receive alarms, trend data and subscribe to reports. The AMBIT plus ESP optimization system adds qualified experts who monitor pump performance and provide recommendations. The top tier, AMBIT 24/7 production surveillance service, is a full-time service in which experts proactively respond to any issues with the ESP and control the pump to ensure that issues are resolved before they become critical.

The systems include a controller, either switchboard or VSD; a downhole gauge; a communications modem; a data center to process and store the data; and an interface that allows users to set and receive alarms, trend the VSD and downhole sensor parameters, record memos, develop custom reports, control the ESP remotely (optional) and track key performance indicators. It also comes with a fully functional application available on Apple or Android devices.

Again, the key is to allow the ESP to dynamically respond to downhole situations to avoid shutdowns and overheating and to improve production. "Real-time modeling and diagnostic algorithms are used to better understand ESP behavior and recommend possible actions," Denney said. "It's highly recommended that an experienced ESP engineer is employed to review the VSD settings regularly and make the proper changes to prevent a premature failure."

He added that the AMBIT platform also can be used for progressing cavity pumps (PCPs) and surface pumping systems and in the future will be available for gas lift, rod lift and plunger lift systems.

Schlumberger's ESP automation solutions can be set to meet the client's production strategy, Mathiravedu said. "This could be a controlled drawdown; sustained operation to cope with unsteady flow via feedback controls on motor current or bottomhole flowing pressure; or severe, unsteady multiphase flow and gas slugging," he said. "In addition, local support for Schlumberger's pumping unit, PCP and ESP divisions provides extremely reliable control systems and high-tier remote monitoring to allow technical and operation experts to see real-time data and history trends wherever needed. This enables proactive optimization to improve production and avoid shutdowns when possible."

Gas lift

Gas lift systems face slightly different issues than ESPs and rod pumps since they require a source of gas to lift the hydrocarbons to the surface. But they're widely used in unconventionals.

"On the shale plays, because the pressures are pretty low, operators start using gas lift from the beginning," said Sudhir Jain, senior oil and gas consultant for Emerson Process Management. "Otherwise that oil will never come up."

Gas lift pumps require a different form of optimization than ESPs. "The interesting thing about this is that, generally speaking, the more lift gas you use, the more oil you can produce—up to a point," said Lou Heavner, a consultant for systems and project engineering at Emerson. "That point is where the backpressure created on the well by too much lift gas is actually inhibiting the flow of oil up the well. There is a natural optimal point for any given well for producing the maximum amount of oil."

Another challenge is the availability of the lift gas itself. "Sometimes if you have a number of wells, you may have a limited supply of gas for the gas lift," Jain said. "That is the time you have to allocate the distribution amongst all of the wells in a way that maximizes total production."

This is addressed by optimization, he said. "Every well has a well test curve, which is basically production rate vs. gas lift at different gas-lift rates. That is one of the essential things you need to have. You want to achieve the optimal flow for each well, but sometimes you don't get to the optimal point because you have insufficient gas."

In a single-well situation where gas is plentiful, added Heavner, the optimal flow rate is determined by the production curve fitted to well test data. With multiple wells and constrained gas supply, or in some cases by other considerations like water production, it's harder to allocate that gas in an optimal way. "That's the optimization problem that we're most enthusiastic about right now," he said.

The solution is offered as either an open-loop or closed-loop system that gives the optimal set points to open or close lift gas valves to vary the lift gas flows for all of the wells using gas lift. "That gives our customers the maximum revenue," Jain said.

Another advantage that Emerson provides in its systems is the wireless component. "Our ability to make communications among the field devices wireless can rapidly improve the deployment of these types of solutions," said Deanna Johnson, global wireless marketing manager at Emerson. "When the unconventional patch was on a tear, you couldn't find electricians to lay wires or people to dig ditches to put the wires in so that they would be protected. Wireless has made a huge difference in people's ability to cost-effectively and rapidly deploy these types of solutions."

The human element

Automation is changing the way people view artificial lift systems. The ability to collect data in real time and control equipment remotely is having an enormous impact on productivity in the field.

"One of the things I've seen on platforms is that even if you have highly trained staff, they can't take full advantage of these systems," Jain said. "And you don't have these kinds of experts all over the world. It's not that it can't be done manually. But modern automation is real-time and does all of the calculations by itself."

While adding automation efficiencies does cost money, the benefits are obvious. "The artificial lift industry as a whole has historically been late to adopt this technology, but those who did adopt new artificial lift technology and automation processes are now in the majority," Mathiravedu said. "Clients are very receptive to automation and improved technology, which ultimately results in increased production, uptime and runlife. In the modern age of remote operations and high-efficiency requirements, smart controllers with real-time optimization and solutions have been adopted and are now heavily relied on."

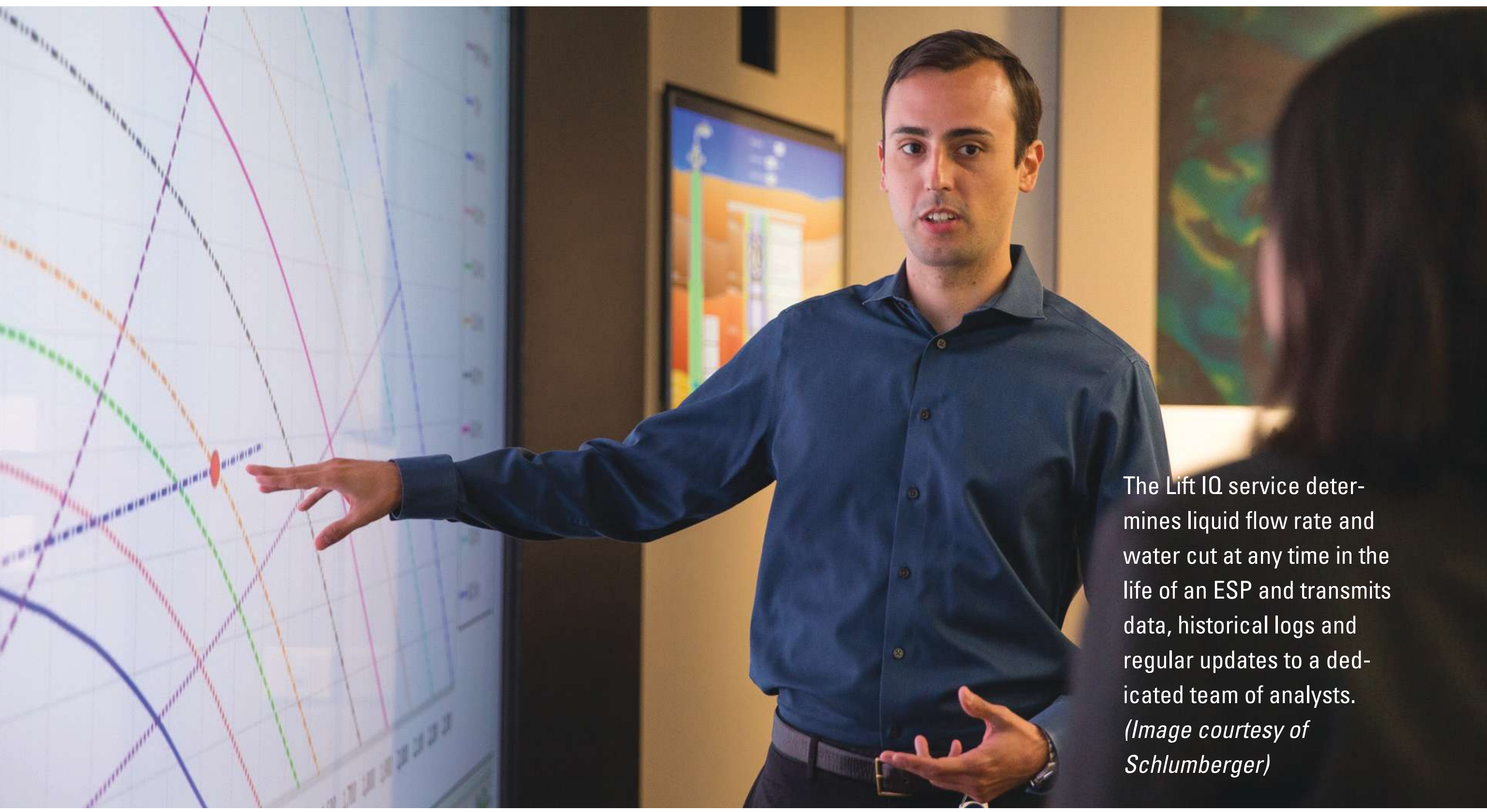
Added Seale, "Just the sheer volume of digital oilfield projects has increased, and customers have really started seeing the benefits of having a real-time center or a collaborative work environment and the value that it gives from an improved workflow and the way that people work." ■

Testing the Untestable

Accurate production trends on inaccessible remote ESP wells are obtainable.

By Lawrence Camilleri
Schlumberger

Measuring well flow rates is arguably the most fundamental form of oilfield production and reservoir surveillance. Even in the most mature oil fields, operators continue to perform production testing even when other forms of surveillance are abandoned for economic reasons, which illustrates the importance of flow-rate data for both the production and reservoir engineering functions. This type of testing provides periodic measurement of oil, water and gas rates per well, which are traditionally obtained using test separators, however multiphase meters are gaining in popularity. Typically, a testing frequency of once per month is targeted, especially where it is a legal requirement. Unfortunately this is often not attained due to logistic due to logistic difficulties such as remote wells in the desert, jungle, unmanned offshore platforms and subsea wells. Obtaining reliable production trends can be further frustrated by test separators being either over or undersized for the well rates, making well production and/or reservoir management virtually impossible at the well scale.



The Lift IQ service determines liquid flow rate and water cut at any time in the life of an ESP and transmits data, historical logs and regular updates to a dedicated team of analysts. *(Image courtesy of Schlumberger)*

2011, the first breakthrough

Where the well cannot be tested by conventional means or a reliable production trend cannot be obtained, the operator can only resort to virtual flowmeters, which use existing downhole and surface instrumentation to estimate flow rates in real time based on physical models, correlations or neural networks. Schlumberger's Lift IQ real-time production flow-rate analysis service is one such proprietary virtual flowmeter specifically developed for electric submersible pump (ESP) wells. The algorithm uses real-time gauge data, which provide the necessary measurement frequency, resolution and repeatability to capture transients. The liquid rate calculation is based on the principle that the power absorbed by the pump is equal to that generated by the motor, which provides an equation that can be resolved for rate.

Analytical equations are used throughout the process ensuring that physics are respected at all times, which yields greater confidence than analogous methods based on correlations and artificial intelligence. Two key features of the liquid rate calculation are:

- The liquid rate calculation is independent of changes in water cut and gas-oil ratio (GOR), which is valuable as they are both difficult to measure and vary with time. In actual fact, the energy conservation principle takes into consideration the changes in fluid properties, as they are implicit in the equations, although not explicit and therefore not required as inputs.
- A single calibration is valid for long periods of time of up to four years in time as demonstrated during the 2011 field trials. Most other virtual flowmeters used within the industry require recalibration every time there is a significant change in water cut and/or GOR, which defeats the purpose for most applications. The single calibration feature is essential to using the flow-rate calculation algorithm in predictive mode.

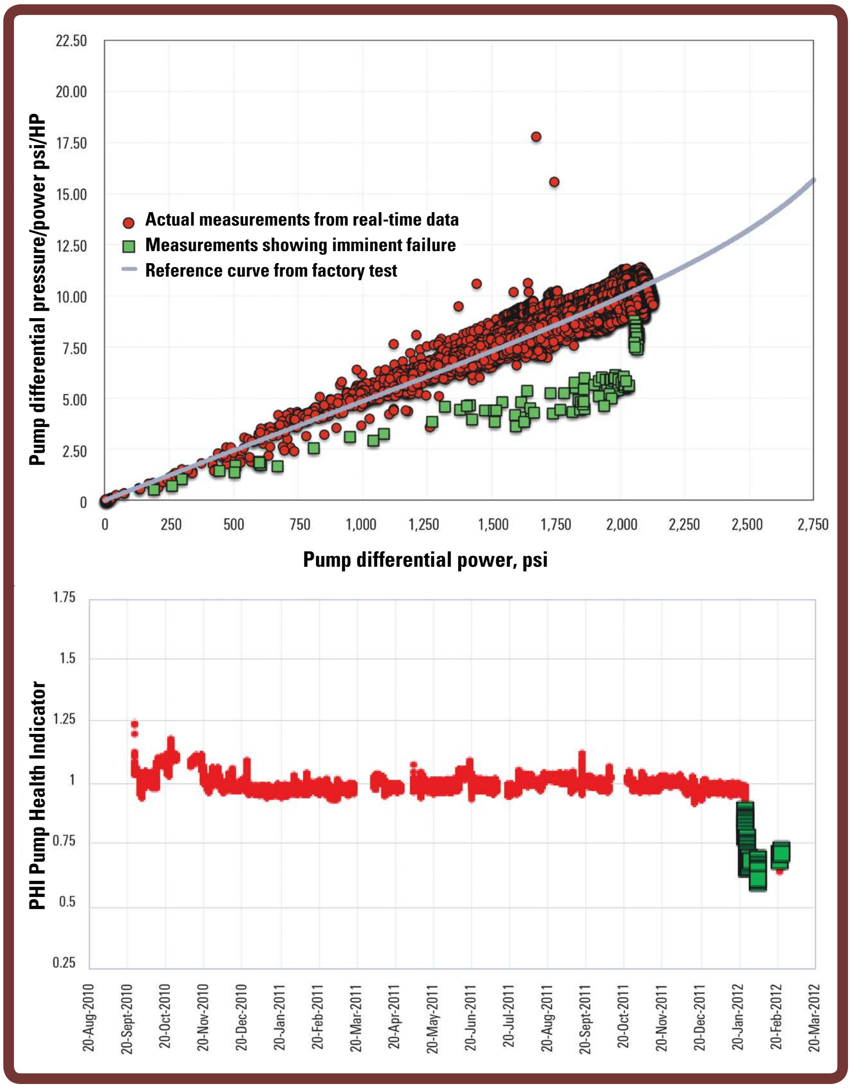


FIGURE 1. An example of the new Schlumberger PHI shows an excellent match. *(Data courtesy of Schlumberger)*

These features were key to enabling the automation of the real-time production flow-rate analysis service and spurred Schlumberger to develop a true real-time liquid rate and water cut calculation process as opposed to post processing gauge data. The Lift IQ engine is located in the Cloud and can be accessed by any well that is connected to the Internet.

2015, the second breakthrough

Even though only a single calibration is required over long production intervals, the real-time flow-rate calculation algorithm had two potential weaknesses up to 2015.

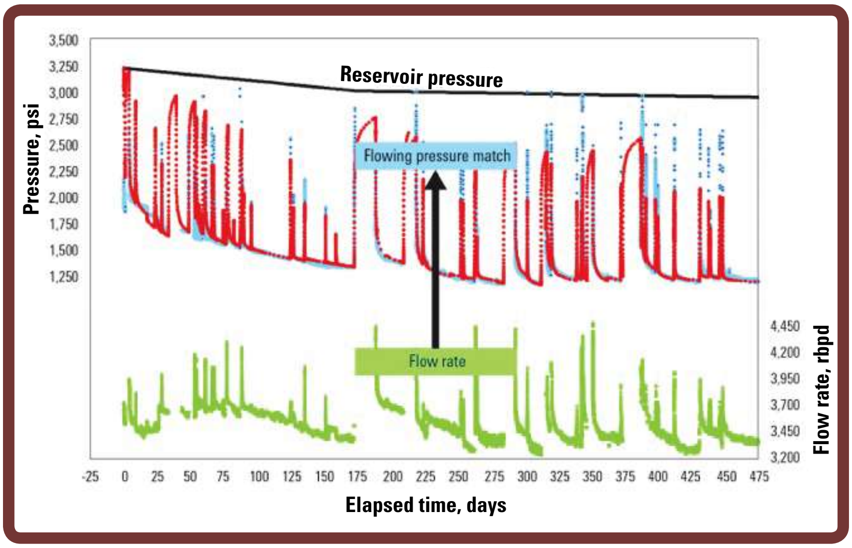


FIGURE 2. A high-frequency flow-rate trend, including transient flow rates, enables pressure simulation and matching during both steady and transient state conditions thereby quantifying depletion. *(Data courtesy of Schlumberger)*

First, how does one know when to recalibrate the flow-rate model? This would be required if there is a degradation in pump performance, which could be caused by either wear, free gas and/or viscosity.

Second, how does one calibrate the algorithm if no physical test is possible at all using a test separator and/or a multiphase flowmeter?

The solution to both these problems was provided by a new Schlumberger proprietary pump diagnostic algorithm called the Pump Health Indicator (PHI). Traditional pump condition monitoring is based on comparing the measured pump differential head with the "as new" head at a given flow rate. The weakness of this process is that it not only requires an accurate flow-rate measurement but also an *in situ* measurement of pump specific gravity to convert measured pump differential pressure to head, both of which often are unavailable. The new method also compares "actual" to "as new" condition, but instead of performing the analysis at a given flow rate, it is done at a given pump differential pressure, which is readily available from real-time data and removes the dependence on flow rate.

Furthermore, the value compared is the pump differential pressure divided by pump absorbed power ratio (DP/Power). This value also can be measured with existing instrumentation and most importantly is independent of specific gravity. Where the actual and reference DP/Power values are equal, the pump is deemed to be in good condition. Conversely, where the values differ, it is an indication that there is pump degradation. In actual fact, one can demonstrate mathematically that the PHI is equal to the ratio of head, flow and efficiency degradation factors thereby providing a holistic indicator of pump performance.

In a recent remote well case study, there was insufficient traditional testing over the 16-month production period to know whether a single calibration of the calculated liquid rate provided a reliable trend or whether recalibration was required. The PHI was calculated (Figure 1) and an excellent match obtained over the entire 16-month period with the exception of the last nine days prior to ESP failure, thereby confirming that a single calibration was sufficient.

Furthermore, as fluid analysis confirmed the absence of gas and/or viscosity, it was possible to use the PHI to calibrate the power model during the first few months of the ESP life when one knows that pump wear is negligible and therefore PHI must be equal to 1.0. In other words, the PHI enables calibration of the liquid rate model if there is no gas, viscosity or wear degradation of the pump, which is the case on most ESP applications during the first few months of operation.

The resulting liquid rate trend is shown in Figure 2, which illustrates how flow-rate transients are captured thereby enabling reservoir simulation to match the flowing pressures both during transient and steady state conditions. This becomes a powerful tool for monitoring depletion at the well scale and thereby optimizing drawdown. ■

References available.

Gas-lift Optimization Solutions for Boosting Operating Margins

Solution uses real-time well data to dynamically optimize production while operating within process and resource constraints.

By Lou Heavner
Emerson Process Management

With today's changing market conditions, oil and gas companies are shifting their focus from capex for development of new well sites to boosting production at existing assets. These companies are implementing strategies that boost profits and lower costs by seeking an investment option that can pay for itself quickly, often in just a few weeks. Today, a vast majority of well operations utilize an artificial lift method such as gas lift to boost output of wells. However, the gas-lift systems on many wells are often poorly operated and infrequently adjusted. They rarely utilize real-time well data making it virtually impossible to respond to changes in well operating conditions in an optimum way. Some assets do not have the advanced functionality required to perform optimization when the site is operating under multiple constraints. Emerson offers a gas-lift optimizer (GLO) solution based on the use of real-time data gathered from wells within an area and dynamically optimizing the performance of the entire production area while operating within process and resource constraints. Oil and gas companies that have implemented Emerson's GLO solutions have experienced an increase of 4% to 15% or greater in operational improvements by optimizing use of existing assets.

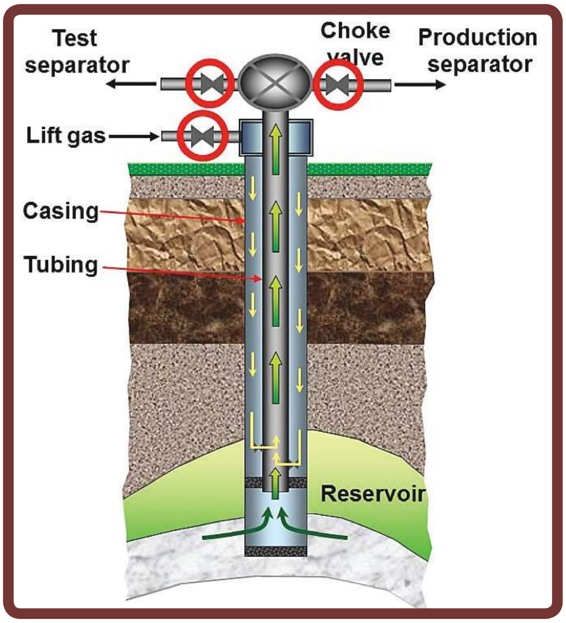


FIGURE 1. Gas lift boosts well production by injecting gas into the well tubing-casing annulus to reduce hydrostatic pressure. *(Images courtesy of Emerson Process Management)*

Optimizing opportunities at multiwell sites

The gas-lift technique of boosting well production works by injecting gas into the well tubing-casing annulus to reduce the hydrostatic pressure that inhibits the movement of the wellbore fluids to the surface (Figure 1). The relationship between gas-lift injection rate and well output flow rate (Figure 2) indicates that increasing the gas-lift injection rate above a certain value might negatively impact the production rate as the backpressure created by the lift gas exceeds the lifting effect. Emerson offers an

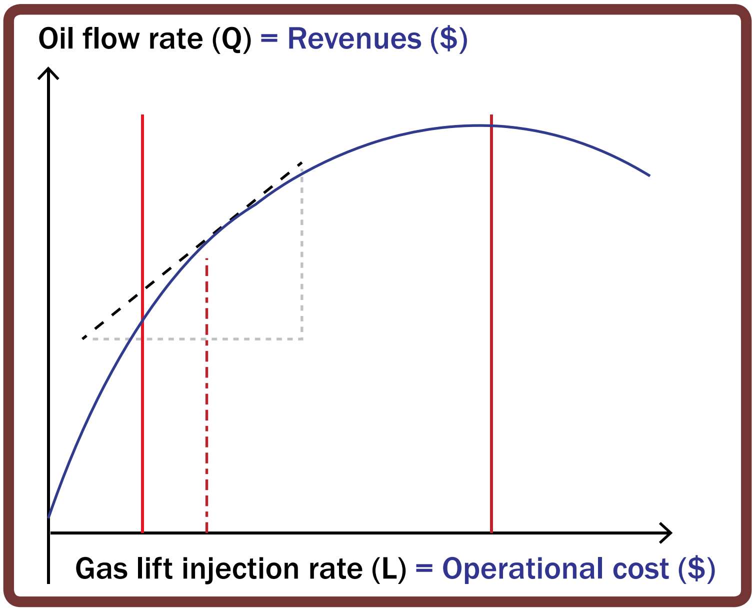


FIGURE 2. Increasing gas lift injection rate above a certain value might negatively impact the production rate as the backpressure created by the lift gas exceeds the lifting effect.

automation solution to optimize lift gas at a well. Controlling the gas-lift injection to maximize production is more complicated when a production area has limited resources such as lift gas that is shared or must be allocated between multiple wells (Figure 3).

It has been common practice to initially set the gas injection rates based on expected well production. However, the lift gas rates remain static and are infrequently adjusted as production changes occur in each well. In some cases well production operators overseeing a production area might adjust the gas injection rates based on weekly or monthly production data making it virtually impossible to respond to continuously changing well performance conditions. Optimal allocation of limited lift gas between multiple wells is even more challenging since each well is unique and has differing production characteristics that change with time.

This argues for closed loop control of lift gas. Automatic flow control valves and flowmeters must be connected to a control system platform such as a SCADA system. The operator sets a lift gas flow rate to the controller instead of manually stroking the lift gas valve. The next step in the hierarchy is for a supervisory controller to adjust the set point. A gas-lift optimizer can set the lift gas for a single well to maximize production of the well. However, a multiwell gas-lift optimizer can optimize the allocation across multiple wells. That can produce real benefits.

There is always concern about closed loop control down at the well pad, which might be unattended for periods of time. So any optimizer solution must be able to operate in open loop or advisory mode. In this case the optimizer does not directly change the lift gas flow set point. Rather it alerts the operator to a need to change the set point and the operator makes the change. Closed loop or open loop, the optimizer is slow compared to a dynamic controller. It recognizes when a constraint is about to be violated and recommends (or makes) an immediate change to the lift gas flow set point, but otherwise it is slowly and continuously seeking the optimal allocation of lift gas. This slow and steady approach minimizes any disruption or introduction of variability to the process. This tends to be “easier” on the reservoir than making periodic step changes typical of a manual operation.

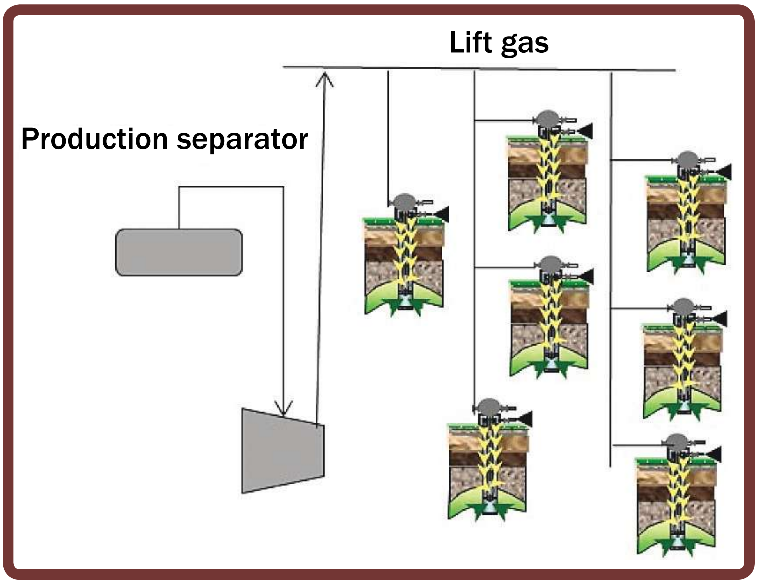
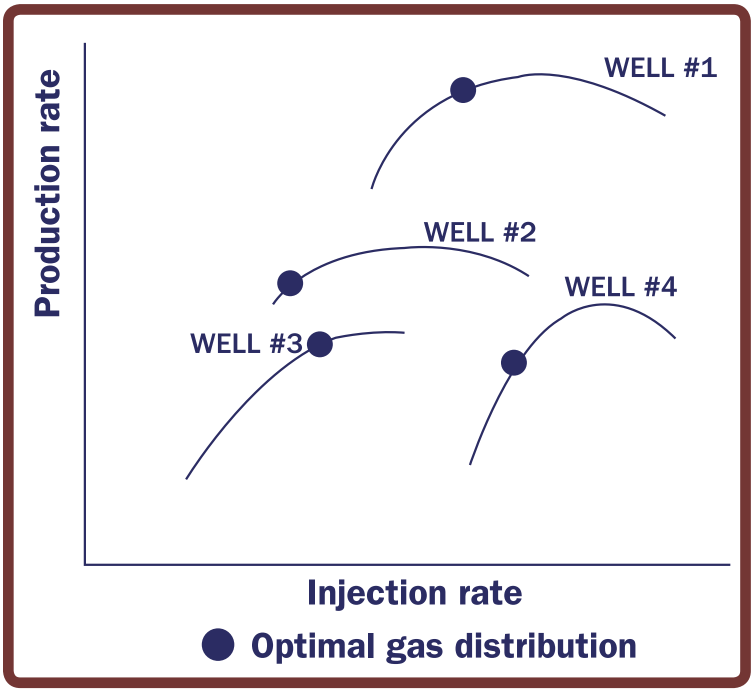
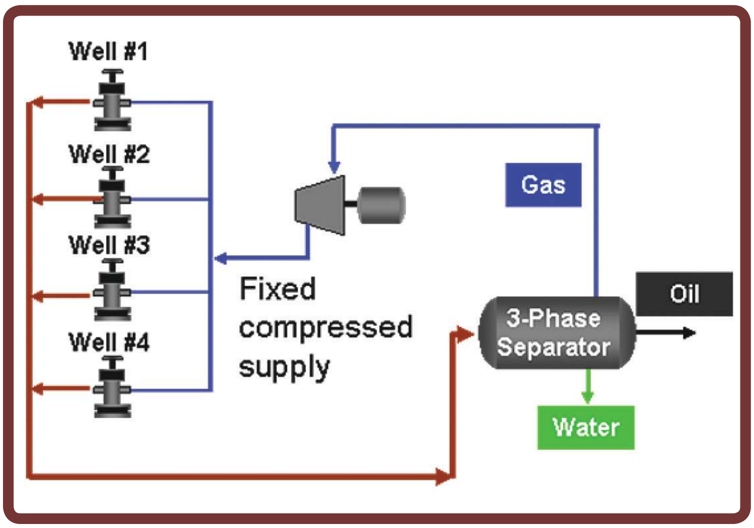


FIGURE 3. Maximizing production is more complicated when a production area has limited lift gas that must be shared or allocated between multiple wells.

Boosting production at multiwell sites

The foundation for the GLO solution is based on gathering accurate and reliable real-time data that measures process related measurements for each well in the area to be optimized. These might include various pressure and flow measurements





FIGURES 4A and 4B. Emerson's GLO solution builds on the real-time-data foundation and includes an online multivariable optimizer that handles complexities like dynamically changing operating constraints for all wells located in the area.

and ratio/volume computations for variables like injected gas lift, wellhead casing/tubing pressure, wellhead output volume, gas-to-liquid ratio and others. Emerson also offers automated well test solutions to support the data requirements for a GLO. Periodic well test data for each well at different gas-lift flow is the key to obtaining good results from a GLO. The well test data need to be validated by an experienced production engineer or equivalent before it is sent to the optimizer. A GLO has a scheduler that can trigger well test notification. It has the capability to determine which wells are flowing freely, lifted by gas or shut in. This is essential to allocate available resources.

The GLO solution builds on the real-time-data foundation and includes an online multivariable optimizer that handles complexities like dynamically changing operating constraints for all wells located in the area (Figures 4A and 4B). The objective is to maximize operating margins for the entire area by equalizing incremental costs for each well vs. lift gas consumption. What that means in simple terms is that no improvement can be obtained by moving an increment of lift gas from one gas-lifted well to another. The optimizer dynamically allocates available lift gas to each well based on overall profitability while honoring all constraints. For example, the gas-lift allocation between the wells is changed automatically in response to changes in constraints such as reduction in gas-lift supply or water disposal capacity. If the available supply is further limited, the optimizer reprioritizes the wells and the lift gas is reduced from the lowest least marginally profitable wells and reallocated to the most marginally profitable.

Abnormal events, such as blockage resulting from flow line freezing or hydrate formation, are detected and the gas-lift allocation is automatically adjusted. Emerson's GLO solution also includes a simulator module that compares simulated performance vs. actual performance for each well to flag excessive deviations. The GLO solution, which might include valves, measurement devices, hardware, software and services, is customized for each site and is easily integrated with any existing automation infrastructure. ■

The Artificial Lift Gap

A new system combines the benefits of gas lift, multiphase flow conditioning practices, research, field testing and operator experience to close the lifting gap.

By Camille Jensen, Dave Kimery and Jeff Saponja
Production Plus Energy Services Inc.

It is common practice in many high initial rate horizontal wells in deep unconventional plays to transition through multiple artificial lift systems. Historically, operators attempt to minimize operating costs by transitioning to rod pumping as soon as possible. However, rod pumping often cannot bridge the gap from natural flow; therefore, a phase of gas lift is today's norm. Multiple lift systems require several planned workovers over the life of the well while challenging producing characteristics increase the necessity for unplanned workovers. As a result, per barrel capex and opex over the life of the well are higher than desired.

> Sometimes the technical envelopes and capabilities of the lowest-cost artificial lift systems overlap and sometimes they do not, leaving a "lifting gap."

The lifting gap

How to combine systems and effectively switch systems while producing the most oil at the lowest cost per barrel is not a simple task for the production engineer. Sometimes the technical envelopes and capabilities of the lowest-cost artificial lift systems overlap and sometimes they do not, leaving a "lifting gap." Maximizing production rate often requires a higher-cost, intermediate-stage artificial lift system like gas lift to fill this lifting gap. This results in a typical strategy of natural flow, followed by gas lift, and finally rod pumping for the remaining economic life.

Natural flow

Natural flow occurs when the reservoir pressure exceeds the total pressure loss through the wellbore from the reservoir level to surface, both hydrostatic and frictional, plus any pressure applied at surface. This can occur when a well is initially brought on production and will terminate when neither of the following conditions are met:

- Normally or overpressured reservoirs where the full hydrostatic column of the reservoir fluids exerts a pressure that is less than the reservoir pressure.
- Sufficient gas production that the fluid velocities and multiphase flow regimes in the wellbore are adequate (above the critical rate) to transport produced liquids to surface.

Rod pumping

Rod pumping is industry proven as cost effective and reliable. Under ideal conditions, rod pumps are highly efficient over a broad operating envelope of production rates and depths. However, they are challenged by gas interference, solids production, the extreme depths of today's unconventional plays and the extra load caused by placing the pump in the deviated section of the wellbore. In practice, these problems limit the rod pumping operating window of rod pumping, thus opening up a lifting gap.

Closing the lifting gap

Gas lift is the common method to close the lifting gap. Production Plus has developed an enabling technology that closes the lifting gap by expanding the operating windows of natural flow and rod pumping, allowing the most hydrocarbons to be produced at the lowest cost.

For all intents and purposes, gas lift is the extension of the natural flow period where the injected gas makes up for the shortfall in produced gas to get the well above the critical rate required to naturally flow to surface.

There are intrinsic benefits of gas lift. It is solids tolerant and manages gas interference. Deviated wells present no issues and corrosion is not a typical problem. Gas lift has the capacity to lift deep wells with a broad technical operating window. For operators with infrastructure and equipment already in place, gas lift is an easy and obvious solution.

Although gas lift is reliable and can handle high initial production declines, it is limited by high bottomhole pressures, restricting drawdown and production, comes with relatively high opex and has additional capex due to the installation of an additional lift system.

Solution

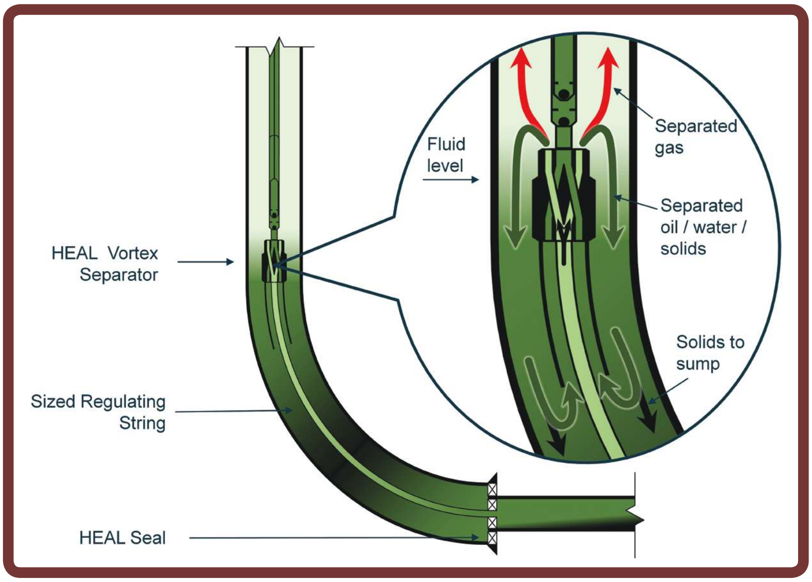
Production Plus discovered that the root cause of lifting inefficiency in horizontal wells is sluggy and inconsistent flow that presents as rapidly fluctuating gas and liquid rates. This complex fluid flow behavior creates an environment for gas interference, is the mechanism for transporting damaging solids and is a root cause for encouraging undesirable proppant production into the wellbore. These struggles of conventional pumping systems result in reduced efficiency, poor runtime and reliability, excessive workover costs and limited drawdown. Gas lift is a fallback solution because it is tolerant to these struggles, although at a high cost.

The company applied the benefits of gas lift, multiphase flow conditioning practices, research, field testing and operator experience to develop an enabling technology, the HEAL System, that closes the lifting gap.

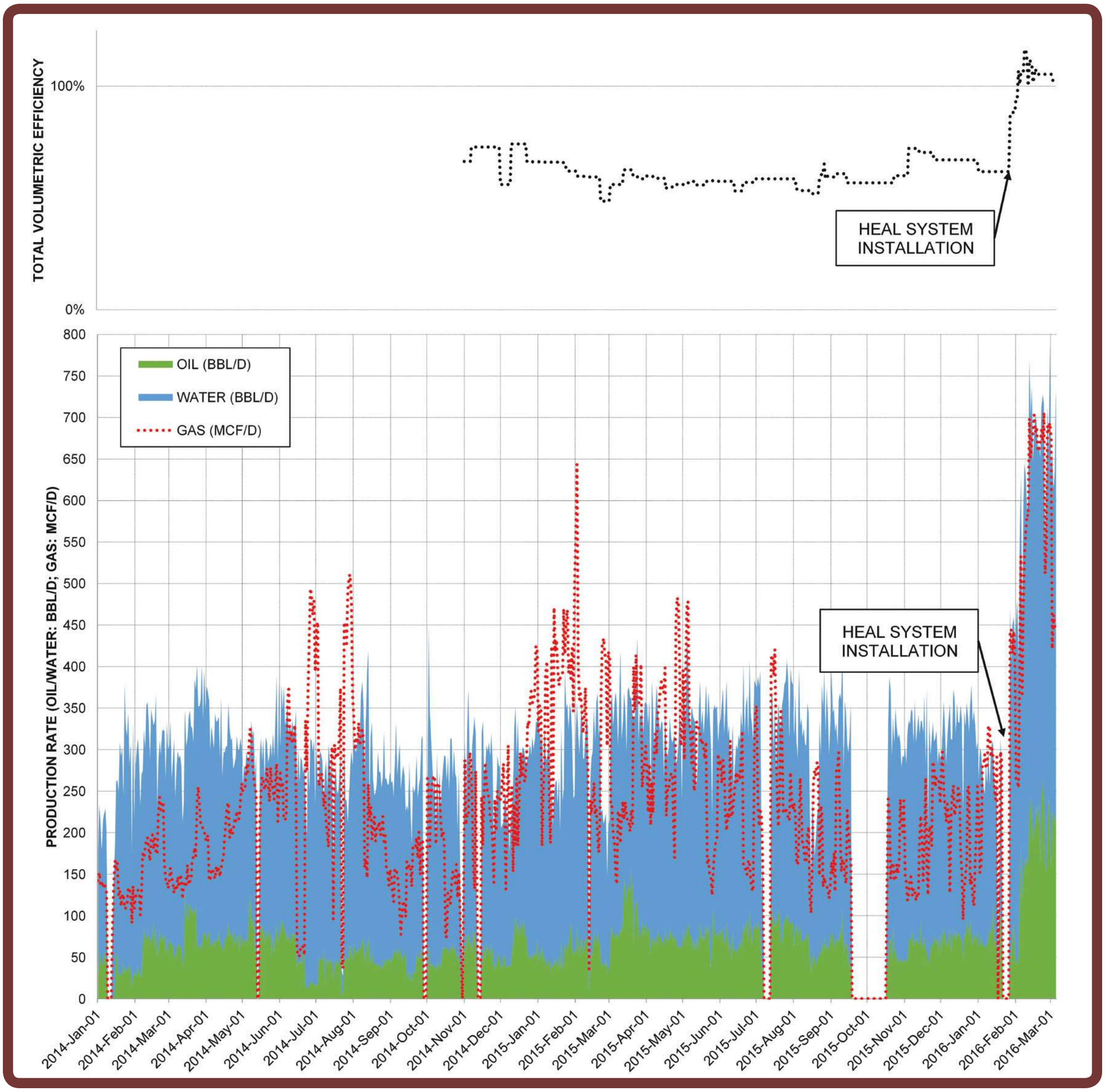
The system lowers a section of production tubing into the bend and reduces tubing internal diameter to achieve critical velocity and fluid flow stabilization from the horizontal to the vertical above the kickoff point. In turn, a conventional artificial lift system can be placed higher and out of the bend, in the vertical where it is designed to be most efficient and reliable.

The system is a mechanical system comprised of three main components: a HEAL Seal, a sized regulating string (SRS) and a HEAL Vortex Separator. The SRS has a sized internal diameter and length specific to the reservoir pressures and anticipated production fluid rates over the well's life cycle. The system is designed to minimize operational risk and maximize reliability, with no moving parts and does not extend into the horizontal.

Smooth, even, liquid flow to the pump offers exceptional conventional artificial lift system reliability and pump efficiency. With higher pump



The cyclonic effect of the Vortex Separator efficiently separates gas and solids from the liquid and protects the pump from damage. *(Image courtesy of Production Plus Energy Services Inc.)*



Applying the HEAL System to a well in British Columbia increased its production rates. *(Image courtesy of Production Plus Energy Services Inc.)*

efficiency, higher production rates are achievable or smaller equipment can be used to at the same production rate.

Case study

A horizontal well in Northeast British Columbia was struggling to maximize production from the well with a typical rod pump. The well had a total measured depth of 2,750 m (9,022 ft) at a TVD of 1,317 m (4,332 ft) and was troubled with gas interference in the pump due to the gas-liquid ratio of 2,500 cf/bbl.

By installing the system the operator was able to move the pump above the well's kickoff point and achieve complete pump fillage, resulting in a much higher production capacity from the existing equipment. Consequently, the operator was able to greatly increase production from the well.

Acknowledgements

This article has been abridged from the original paper and case studies published as part of the 2016 Southwestern Petroleum Short Course. ■

Enhancing Value by Maximizing Production, Minimizing Operational Cost

New continuous capillary line tool helps deliver chemical downhole with improved efficiencies and reduced operational costs.

By Darren Wiltse
Progressive Completions Ltd.

In these trying times, enhancing operational value is of primary importance. In the uncontrollable and persistent low commodity price environment that the industry is currently faced with, the only way to enhance value is to focus on operational costs.

Oil and gas assets that provide operational challenges like corrosion, organic/inorganic deposition, emulsion and other naturally occurring challenges that reduce production by interfering with and reducing the efficiency of the concerning artificial lift system can be efficiently controlled with a cost-effective chemical placement system. The performance of which is greatly enhanced when the appropriate chemical is placed at the inlet of the bottomhole pump.

A very successful way to transport chemical downhole is with a continuous capillary line. When properly controlled, a capillary line injection system can reduce chemical costs by as high as 80% when compared to batch and casing annulus injection from the wellhead. A capillary line is proven to greatly reduce downtime, improve efficiency and ultimately reduce operational costs.

Rod pump challenges

When considering a reciprocating rod pump artificial lift system there is additional complexity for chemical conveyance in that the production tubing is anchored and placed in tension. The anchor is positioned above the reciprocating rod pump and therefore acts as a

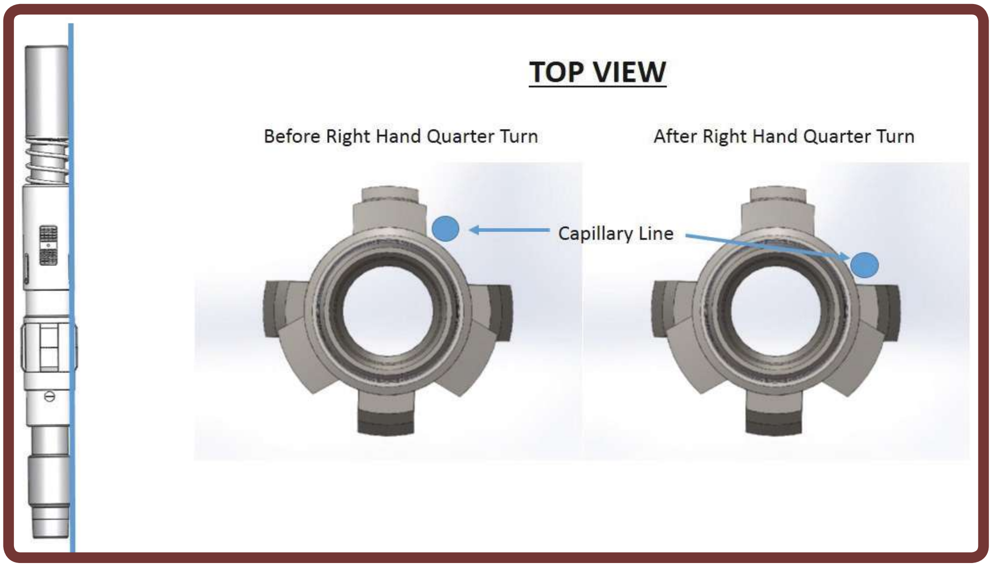


FIGURE 1. A capillary line bypasses the anchor to ultimately terminate into the rod pump inlet, and the anchor requires a quarter turn to set protecting the capillary line. *(Image courtesy of Progressive Completions Ltd.)*

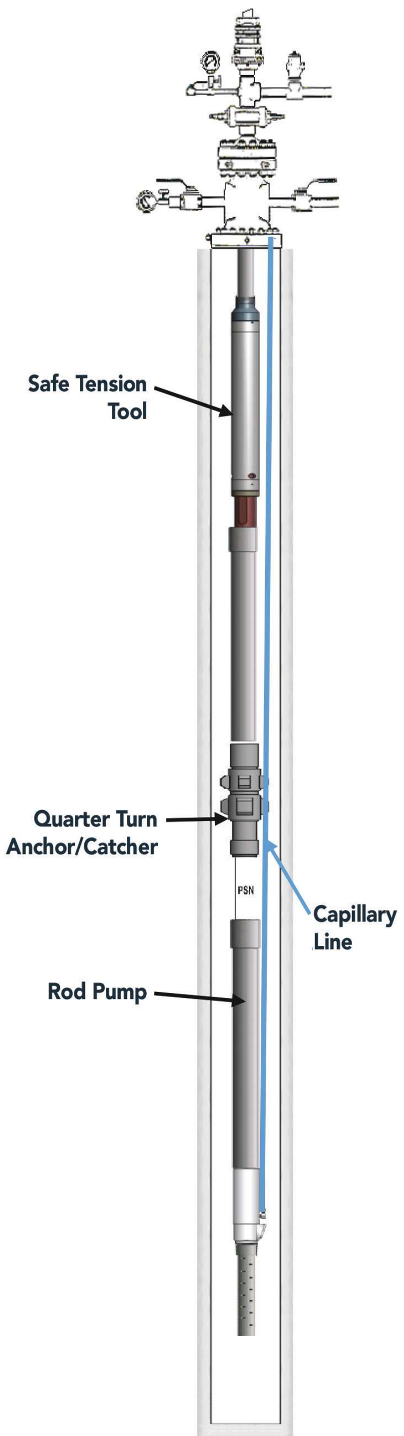


FIGURE 2. A capillary line extends past the Quarter Turn Anchor/Catcher terminating in the chemical injection sub beneath the rod pump. Tubing is set in tension with the Safe Tension Tool. *(Image courtesy of Progressive Completions Ltd.)*

barrier, preventing chemical capillary lines to run into the inlet of the bottomhole pump.

Adding to this challenge is the way in which anchors are set. Conventional anchors require many turns of the production tubing during setting operation, which would in turn compromise the capillary line.

For wells that require a second barrier of well control, specifically requiring BOPs to be engaged, threading capillary line through the wellhead is extremely unsafe and is in contravention to the requirement.

Solution

A twofold improvement to the mechanical anchor design has been made to facilitate the successful application of the capillary line (Figure 1).

Part one of the two-part solution includes a major redesign of the anchor body to provide sufficient annular area for the capillary line to bypass it and terminate into the rod pump beneath. It also included a major redesign to the setting system that only requires a quarter-turn to set the anchor.

The capillary line is no longer in jeopardy during anchor setting procedure. Finally by adding a "catcher" capability, tubing is prevented from falling should it fail above the anchor.

The second part to the solution was to develop a tool that allows the threading of the capillary line through the production tubing hanger with the BOPs engaged and placement of the production tubing string in tension with full well control.

The Safe Tension Tool was developed to do just that (Figure 2). It is a patented telescopic tool that connects directly beneath the wellhead production tubing hanger. With BOPs installed with full well control, the tubing hanger and capillary line are pulled through the BOPs allowing the safe plumbing of the capillary line through the hanger. The hanger is then lowered back through the BOPs and into the wellhead.

The system is then ready for setting the Quarter Turn Anchor/Catcher. Once the anchor is set the Safe Tension Tool is then pulled and retracted sufficiently to place the entire production tubing string in tension without compromising the capillary line.

History

This system is now being used throughout North America. Examples range from successfully incorporating the system in an entire field to greatly reduce the effects of paraffin to the bottomhole rod pump, to enhancing the performance of problematic wells, and everything in between.

It recently has been recognized as a solution by an operator in the Permian Basin. The application there required chemical to be conveyed toward the inlet of the reciprocating rod pump artificial lift system so as to reduce the effects of scale buildup.

Creating more value

Reciprocating rod pump lift systems are by far the most popular artificial lift system in the industry. Because of its popularity and effectiveness it continues to be used in more extreme applications. A cost-effective chemical placement system helps rod pumping systems overcome the negative effects of corrosion, paraffin, scale, emulsion, and other rheological and mechanical challenges. The system will help improve operational performance of rod pump lift systems, reduce down time and enhance production volumes. ■