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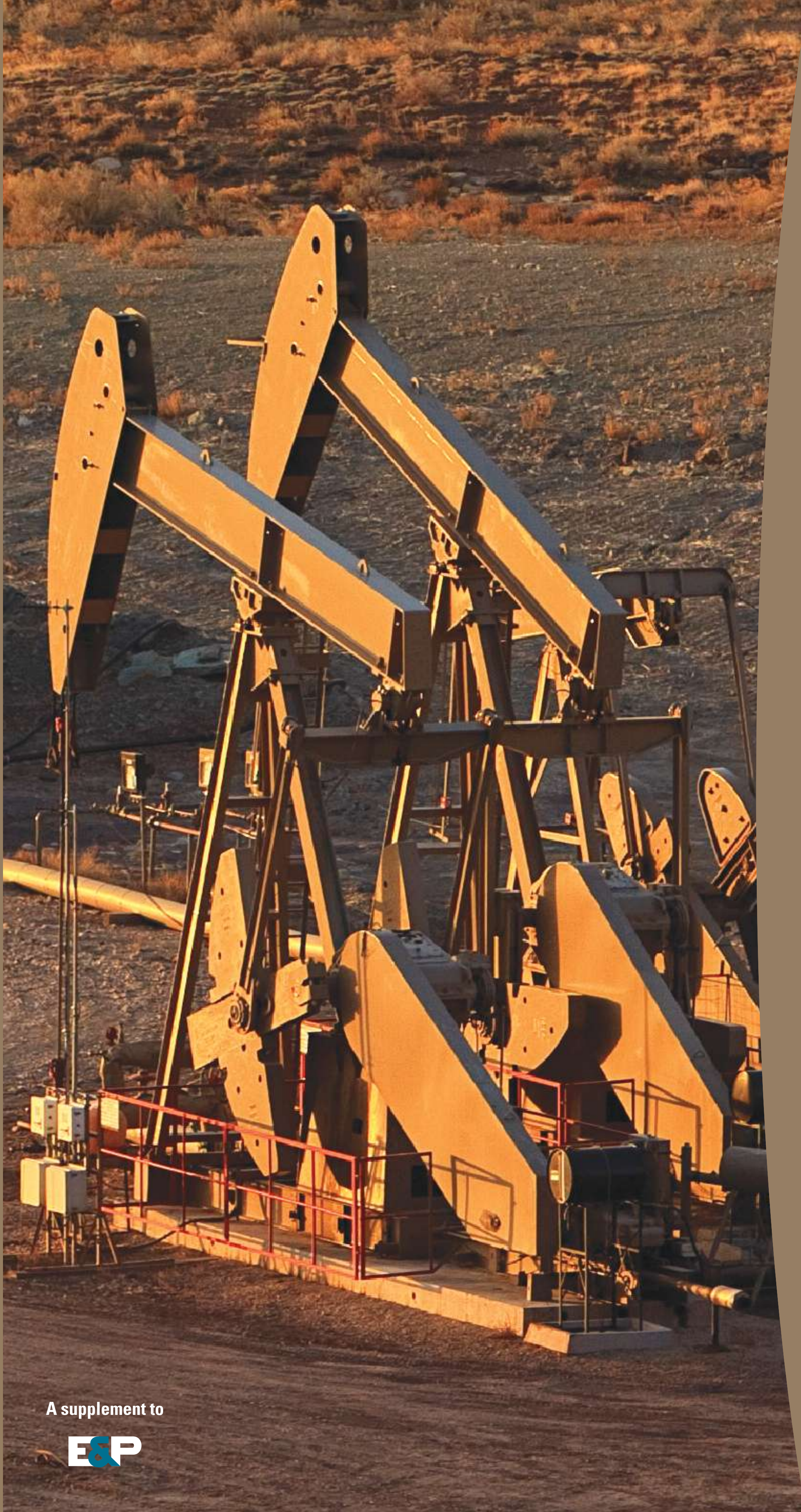
Artificial Lift Techbook



A supplement to

E&P

E&P

Artificial Lift
The 2014 Techbook

A supplement to *E&P*

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Hart Energy's Techbook Series

The 2014 Artificial Lift Techbook is the fourth 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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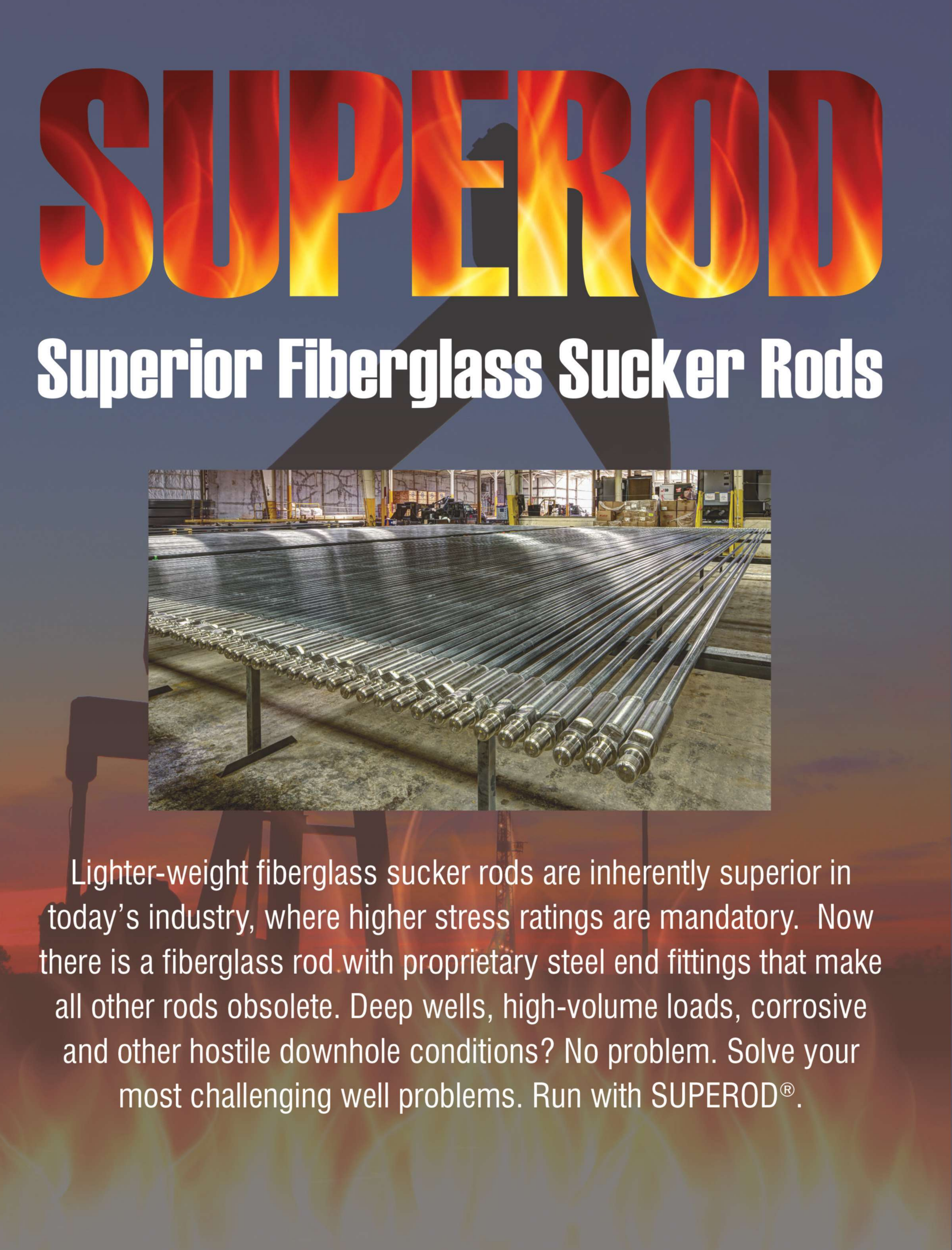
The sun rises as Newfield's dual pumpjacks work in the Greater Monument Butte area. *(Photo courtesy of Hart Energy's* Oil and Gas Investor, *by Tom Fox)*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An Unconventional Spotlight for Artificial Lift

With more than 90% of the world's wells using some form of artificial lift, the future is bright for the tried and true technology.

By Jennifer Presley
Senior Editor

Derricks and pumpjacks: icons of petroleum production. To many outside of the industry, one immediately follows the other into the field to help keep the oil flowing. Industry insiders, however, know that this is not always the case and that a beam pump nodding on the horizon is but one of the many different forms of artificial lift available.

The "Shale Gale" has brought the drilling of tens of thousands of new shale and other unconventional wells to the U.S. It is only a matter of time before artificial lift systems move in and take up the task of producing hydrocarbons from these wells.

According to a recent *Markets and Markets* report, more than 90% of the world's oil-producing wells currently are using several types of artificial lift systems. While artificial lift systems have evolved over the years, it is their current application in offshore wells or in onshore lateral wells—like the unconventional reservoirs themselves—that is serving up a new batch of technology challenges.

Electric submersible pumps (ESPs), rod lift, plunger lift, gas lift and progressive cavity pumps (PCPs) are the major types of lift systems used in the field. ESPs command the largest share of the artificial lift market, with rod lift following in second position, according to the *Markets and Markets* report.

In this first edition of Hart Energy's *Artificial Lift Techbook*, different aspects of the market, technology, challenges and more are reviewed.

The discussion opens with *Markets and Markets* providing an in-depth look at the current state of the global artificial lift market with updates on the status of the technology's use in the recovery of shale oil, coalbed methane and heavy oil.

In the Key Players section, a brief description is given for those companies that have demonstrated leadership with innovative technology and services to operators and that are ready to meet the artificial lift challenges ahead. Included in this chapter is a comprehensive listing of more than 30 companies as well as the lift solutions that some companies offer presented in a table format.

The Technology Overview section includes insights from Cleon Dunham, president of the Artificial Lift R&D Council, and other experts on the different types of lift, applications best suited for each and ways to optimize production.

Facing page:
Dual pumpjacks and a tank battery are seen at sunrise in Newfield's Greater Monument Butte Unit.
(Photo courtesy of Hart Energy's Oil and Gas Investor*, by Tom Fox)*

Lift types covered in this section include ESPs, sucker-rod lift, plunger lift, gas lift, chemical lift, PCPs and hydraulic pumping systems.

Case studies follow, with three providers sharing their solutions to common artificial lift challenges. This chapter includes case studies that address a variety of challenges encountered in unconventional wells, including:

- Sand production in unconventional wells and the need for filters when using ESPs in these types of wells;
- How an extended-reach gas-lift system brought success to a difficult well in Argentina; and
- Extending the life expectancy of sucker-rod-lifted horizontal and highly deviated wells using sucker rod guides.

In the Challenges section, many areas of R&D that currently are underway to address the common areas of difficulty in artificial lift are reviewed, including handling particulate matter and gas separation, automation and high temperatures. Collaboration between companies, academia and industry organizations is helping to uncover solutions and make technical innovations.

Artificial lift, like EOR, is a production technology that will long have a place in the brown and green fields of the world. Optimizing recoveries from these fields will always be the challenge that keeps operators and production engineers busy for many more years to come. ■

Artificial Lift: A Market Overview

The artificial lift market looks bright thanks to unconventional, subsea and heavy oil installations.

By Vineet Pandey
Markets and Markets

Globally, about 91% of oil-producing wells currently use or deploy several types of artificial lift systems to bring hydrocarbon resources to the surface from resource beds. In cases where there is sufficient reservoir pressure, natural lifting of the crude oil occurs. However, reservoir pressure often is found to be low in mature fields, and the number of naturally flowing wells also decreases. As a result, E&P companies use artificial lift systems to provide external pressure.

The technology for artificial lift has evolved over many decades, and lately these systems have been customized to suit the borehole conditions of the production well. The design of the lift and its capabilities are very critical for ensuring process efficiency and vary according to the physical standards of production wells. Major types of artificial lift systems used in the oil and gas sector are rod lift, plunger lift, gas lift, electric submersible pumps (ESPs) and progressive cavity pumps (PCPs).

ESPs command the largest share within the artificial lift market in terms of value and the second largest in terms of installation. Rod lift follows the ESP type in terms of value and leads the market in terms of volume with the highest number of artificial lift system installations worldwide. Major players in the artificial lift market are Weatherford International Ltd., Baker Hughes Inc., GE Oil & Gas, Halliburton Co., Borets Schlumberger and Kudu Industries Inc.

Shale oil and CBM: boon for artificial lift

Shale oil and heavy oil are driving the demand of artificial lift. The demand for these oil resources is expected to dramatically increase in the coming decade. These resources are hard to extract and require sophisticated recovery methods and machinery for successful production rates. Growth of production activities for unconventional hydrocarbon directly affects the demand for artificial lift. The share of artificial lift installed in unconventional oil-producing wells is collectively rising. Primarily, PCPs, ESPs and rod lift are found useful in carrying out production activities in unconventional wells.

U.S. shale plays like the Eagle Ford, Bakken and Monterey are major producers of shale oil, and production of this kind has grown about 26% annually from 2004 to 2012. Rod lift and ESP manufacturers are expected to generate higher levels of revenue from countries like the U.S., Russia, China and Australia due to a high level of production activities of shale oil in these regions.

Growth in coalbed methane (CBM) production will result in increased demand for PCPs. This is because gas dewatering wells for CBM are one of the applications for PCPs. The U.S. produces about 80% of the global CBM production and has the largest installed base of CBM gas dewatering wells for PCPs. Future demand is foreseen to be high in countries such as Russia, China and Indonesia, which have plans to increase CBM production. Russia and China aim to reach a production of 400 MMcf/d by 2020 and 2 Bcf/d by 2015, respectively.

Subsea installation, heavy oil resource development

Seventy percent of the world's oil and gas production is derived from mature fields, including an appreciable percentage of fields in the secondary or tertiary production phases. One reason for this is several E&P companies have started venturing into deep and ultradeep offshore development and heavy oil resource development. In 2012, deepwater oil and gas production accounted for 6% of total oil and gas production. Offshore Brazil, the Gulf of Mexico and West Africa are the most active deepwater crude oil production regions and are estimated to have an additional 320 Bboe of unexplored deepwater reserves. Production activities in these regions are undergoing a continuous revision to evolve into economically viable processes and yield desired profits. Subsea installations are a part of deepwater resource development and are expected to grow exponentially in the coming years. There has been a threefold growth in the number of subsea wells in the last decade. This assures growth within the ESP market in these regions.

In past years, key market players have been focusing on expanding their product portfolio and venturing into submarkets; this has resulted in the consolidation of the artificial lift market.

Heavy oil resources mostly are found in Canada, Venezuela, Nigeria, Iraq, China and Russia. Canada and Venezuela account for 66% of the global oil in place and have a high demand for ESP and PCP systems, which can aid in the development of their heavy-oil resources. Canada and Venezuela combined hold more than 57% of the global PCP market, and Venezuela's ESP market is expected to experience growth of more than 15% annually from 2014 to 2018.

Consolidation

In past years, key market players have been focusing on expanding their product portfolio and venturing into submarkets; this has resulted in the consolidation of the artificial lift market. Major oilfield equipment and service providing companies have begun manufacturing artificial lift and its components or have acquired companies that manufacture artificial lift and its components.

A distinct trend of market consolidation was observed with the number of market participants witnessing an approximate 50% shrinkage in number. This trend started in 2009 and has continued through 2013. This current market situation projects a cluster of only a few major oilfield equipment and service providers participating in the artificial lift business in the near future. A series of acquisitions started when Baker Hughes acquired Tanroc Equipment Ltd. and Russian ESP major Oilpump Services in 2010. This acquisition was followed by Halliburton acquiring Boots & Coots Inc. in September 2010. GE Oil & Gas acquired ESP manufacturer John Woods Plc in 2011 and rod lift major Lufkin in 2013.

This market consolidation trend hints at the reassured growth of the artificial lift market.

Rental market

Run life and cost of equipment are the primary factors that influence the rental market. Other than rod lift systems, these factors have not favored any other artificial lift system in the past. With technological advancements in the adaptability of the design and increased efficiency of the components, the average run life of some of the lifts has increased drastically. This situation also has made the rental market as yielding as the lift-selling market among lift manufacturers.

The artificial lift equipment rental market has a high penetration in the U.S. and Canada. The rental market acceptance trend is high for rod lift and ESP equipment. This trend is expected to create a huge opportunity in technical service agreement-based fiscal regimes like Oman, Iraq and Egypt.

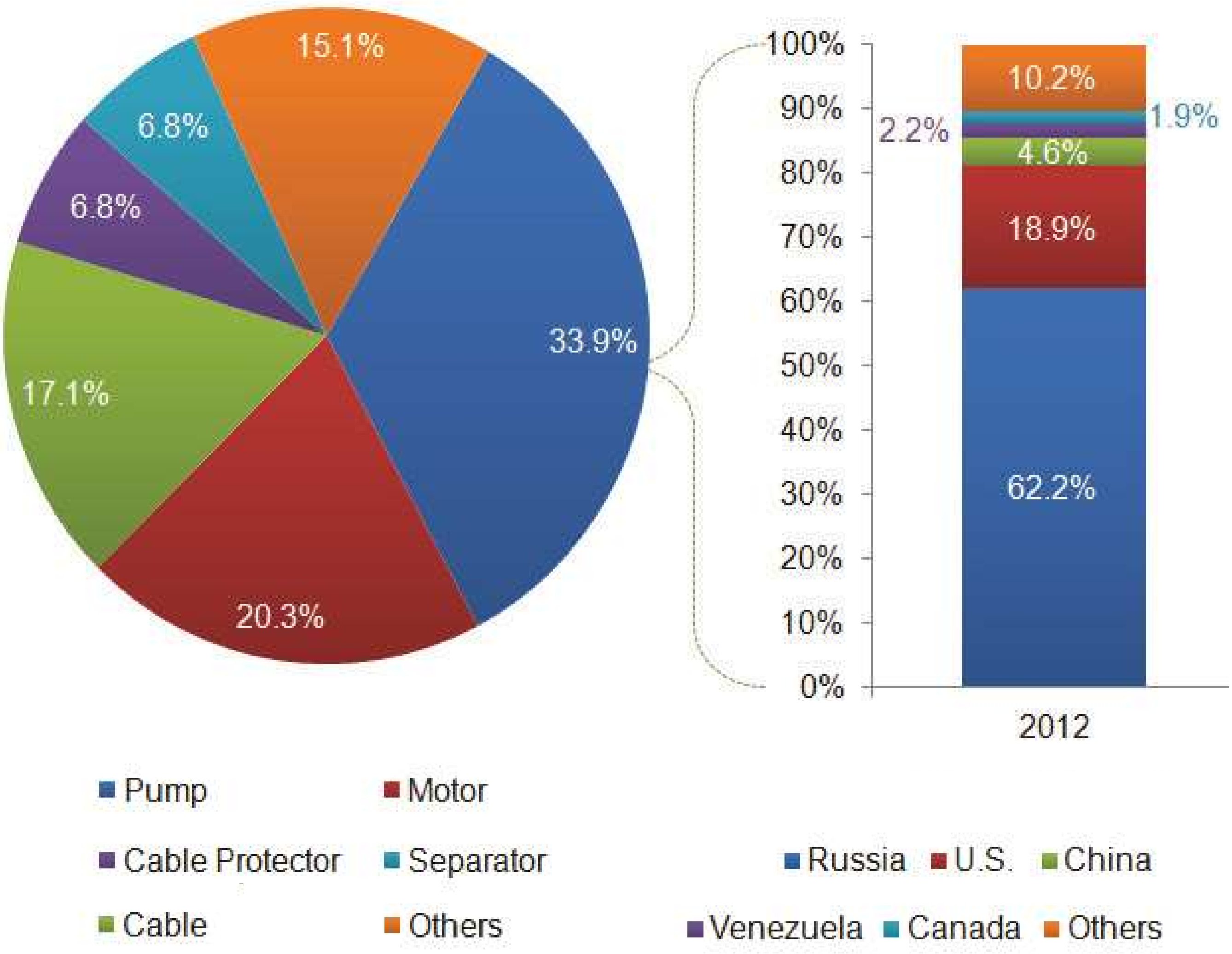
Aftermarket

The aftermarket for artificial lift also is growing with the increasing number of installations. The market exhibits a cyclic fashion, which

involves new system installations and component replacements due to differences between run life of components and the number of producing wells. Pump replacement is the largest segment within the ESP, PCP and rod lift component aftermarket.

ESPs, motor and cable segments are anticipated to be the revenue pockets for the ESP market and collectively contributed about 71% to the total ESP market. Sixty-three percent of ESP, motor and cable sales in 2012 were generated through the component replacement market. Out of the total installed PCPs in 2012, about 74% were installed to replace old, inefficient PCPs, while 48% of the rod lift market's revenue was generated through the pump component for rod lift. ■

ESP Component Market Share and ESP Market Share by Country



(Source: Markets and Markets)

Market to See Extensive Growth in Next Five Years

Artificial lift key players are ready to meet challenges.

By MJ Selle
Contributing Editor

According to a recent report, the market for artificial lift systems will grow to $13.7 billion through 2018 due to the development of unconventional shale plays and liquids-rich resource plays worldwide.

The artificial lift market hosts a variety of pumping systems including electric submersible pumps (ESPs), rod lift, gas lift, progressing cavity pumps (PCPs), hydraulic lift and plunger lift. Statistics show that at least 94% of oil wells will need pumps or lifts at least once in their lifetime.

The report is titled "Artificial Lift Systems Market by Types (ESP, PCP, Rod Lift), by Component (Pump, Motor, Separator, Cable, Pump Jack, Sucker Rod), by Countries (U.S., Canada, Russia, China, Venezuela)—Trends & Forecast to 2018" and is published by *Markets and Markets*. It estimated that the ESP market in Russia and the U.S. will grow collectively 10.5% by 2018. Russia and the U.S. have the largest installed base of ESP systems.

More than 50% of the global rod-lift market was based in the U.S. in 2012, and this segment is estimated to grow at 6.7% in the period due to unconventional oil production. This growth in rod lift will sustain the sucker-rod market, which was projected to grow by 8% during the 2013 to 2018 time period.

Another area of industry growth is in the optimization of lift technologies through remote monitoring systems that provide 24/7 control of pumps and the ability to shut them down immediately if problems are detected.

The following key players have demonstrated leadership with innovative technologies and services for operators and are ready to meet the challenges ahead.

Accelerated Production Systems

Headquartered in The Woodlands, Texas, Accelerated Production Systems has grown from its inception in 2008 to encompass 500 employees working in 30 locations across the U.S. and internationally. Accelerated provides hydraulic-lift solutions along with pump systems, critical process equipment and systems, and design, engineering and support services.

According to the company website, Accelerated operates in 17 U.S. states and such international locations as Canada, Indonesia, Australia and New Zealand, India, Pakistan, the Middle East and Latin America.

In 2013, the company acquired Texas Systems & Controls Inc., along with DynaFlo Artificial Lift Systems and Five Star Equipment.

The addition of Texas Systems & Controls Inc. allowed Accelerated to strengthen its capabilities in the design and manufacture of artificial lift equipment. The facility in Tomball, Texas, triples the company's fabrication space, said President of Accelerated David Martin in an April 2013 press release.

Accelerated noted in its June 2013 press release that DynaFlo and Five Star Equipment brought

Accelerated a line of field-proven electric submersible pumps (ESPs) and related services geared for unconventional wells. DynaFlo, based in Skiatook, Okla., has field locations in Oklahoma, Wyoming and Kansas while Five Star operates out of Ramona, Okla. Available ESP equipment includes pumps, motors, cables, surface controls, pump testing and field service capabilities.

Accelerated offers artificial lift solutions that are suited for horizontal and deviated wells, high levels of abrasive sand, increased amounts of flowback and produced fluids that collectively make traditional artificial lift solutions less efficient, said Brad Goebel, Accelerated's CEO, in the press release.

The company's core business line includes hydraulic-lift (jet pump) systems, gas-lift systems, surface pumps, offshore FPSO solutions, filtration, separation, heating and other fluid handling applications.

Accelerated's hydraulic-lift systems can be used in deep wells that present challenges such as solids, sand, paraffin, heavy oil, water, gas or corrosive fluids. The pumps also can be installed in deviated wells, offshore platforms, remote jungle areas, urban areas and environmentally conscious areas. Special pump designs are available for completions as sliding sleeves, gas-lift mandrels, coiled tubing, drillstem testing and well cleaning and testing.

The hydraulic jet pump is typically used with higher pressure reservoirs, while the hydraulic piston pump is geared toward lower reservoir pressure applications. Hydraulic piston pumps operate similarly to sucker-rod pumps but are actuated hydraulically from the surface rather than mechanically with a sucker rod. The system uses the well fluid rather than hydraulic oil as the power fluid.

The company's piston pumps have been used for more than 35 years to produce some of the deepest oil wells in North America. In remote and urban locations, the self-contained units give operators the option of using natural gas produced by the source well to run the unit. As a low-profile unit, the piston pump does not interfere with irrigation systems and, when used with a packer, the piston pump can be the solution for testing and operating in multiple zones.

Hydraulic pumping's main advantage is that the subsurface pump can be retrieved by reversing fluid flow, eliminating the time and cost for wireline or workover rigs. The hydraulic piston pump also allows controlled changes in the pumping rate over a wide range of capacities, bringing rapid "trimming" of the system to accommodate changing well conditions such as the effect of waterflooding or declines in well production capability.

Combining technologies is possible, since Accelerated offers multiple artificial lift solutions. This combination system is generally run when gas lift is considered to be the long-term form of artificial lift for a well but there is no makeup gas available. A combination system allows an operator to use jet lift initially to kick off the well and dewater the fracture until gas starts being produced.

Accelerated also offers customized designs featuring ESPs. The DynaLift series pump line uses tungsten carbide for increased pump longevity. Features include:

- 300, 400 and 500 series pumps for 4.5-in. to 7-in. cased wells;
- Stainless steel or carbon steel configurations with monel coating options available;
- Pumps with 75 bbl/d to 9,000 bbl/d rates readily available; and
- Highest quality type 1 Ni-Resist and K500 monel components.

Baker Hughes Inc.

Baker Hughes' portfolio of artificial lift products and services includes electric submersible pumps (ESPs), progressing cavity pumps, horizontal surface pumping systems, gas-lift systems, power supply and control systems, and monitoring and automation services.

These artificial lift solutions are present in many challenging environments, from deepwater subsea boosting systems to extreme temperature steam-assisted gravity drainage oil sands projects to unconventional oil wells to high-pressure/high-horsepower, high-flow rate wells.

In addition to Baker Hughes' application engineering and installation services, the company also offers artificial lift monitoring and automation.

Newly introduced Baker Hughes artificial lift technologies are geared for unconventional oil wells with challenging production profiles, conventional wells with high gas-oil ratios or high-gas content in the production stream, and wells with quickly changing flow rates.

Baker Hughes said it designed the ProductionWave FLEXible production solution to provide operators with greater production rates at lower operating costs compared to traditional rod-lift systems. The solution also includes technology designed to minimize the impact of gas on ESP systems. Since unconventional oil plays often contain gas that can reduce the pumping efficiency and increase the power consumption of ESPs, this gas mitigation technology can help boost ESP performance.

A Baker Hughes' employee installs part of the FlexPump system. *(Images courtesy of Baker Hughes)*

The ProductionWave solution features several technologies including the FLEXPump series pump, the Gas Avoider pump intake, the Centrilift Multiphase Pump (MVP) and the GM Performance Series rotary or vortex gas separators.

When free gas is present in the production fluid, ESP systems can suffer performance degradation, which leads to lower efficiency or downtime due to gas blocking, gas locking, gas surges or gas slugs. The FLEXPump series pump design offers wider stage vane openings, which reduce pump plugging and give ESP systems better capabilities to handle solids and gas. Baker Hughes has found that the FLEXPump can handle up to 70% free gas compared to the industry's standard free-gas-handling capability.

To specifically prevent production interruptions and boost performance, the Gas Avoider pump intake's gravity cups swivel to close off upper entry ports during system installation. Gas can then migrate past the intake while the lower gravity cups open to allow entry of higher amounts of fluid. The intake keeps gas from entering the pump, no matter where the ESP system is oriented in the well.

In extreme gas conditions, the Centrilift MVP can be installed in conjunction with the FLEXPump series pump. The MVP reduces the tendency for underload shutdowns due to gas interference through its split-vane impeller design.

The GM Performance Series rotary or vortex gas separators are used to separate free gas from the production fluid, thereby providing added protection against gas entrained in the production fluid.

When gas accumulation in the pump prevents fluid progression through the ESP system, gas locking occurs and the system shuts down. Repeated shutdowns have a negative impact on the longevity of the system. However, Baker Hughes believes gas locking can be managed to prevent wear and tear as well as deferred production.

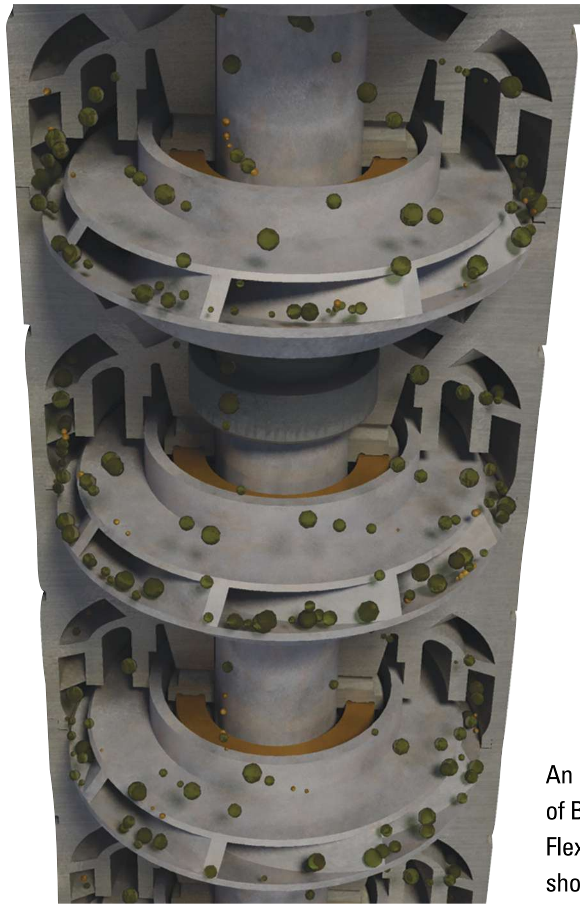
To manage gas locking, the company has developed gas-handling software that is installed in its Electrospeed Advantage variable speed drives (VSD).

The MaxRate software adjusts the frequency of the VSD to mitigate gas locking or pump-off conditions by running through sequences triggered by the system's torque. The software automatically resets the VSD to slow down the ESP system to a rate where fluid is no longer being produced to the surface. Backflow through the pump begins, and gas accumulations are "flushed" from behind the impeller vanes. Once the gas lock is cleared, MaxRate signals the VSD to ramp up the speed to begin pumping. If the software determines that the gas lock situation has not cleared, it will stop the system to prevent any damage.

In one case study after the MaxRate technology was deployed and the ESP system was stabilized, Baker Hughes found the ESP production improved by three times compared to the rod-lift production.

The MaxRate software also contains logic to manage drawdown in challenging situations such as horizontally completed wells and long-duration gas slugging.

In addition to the MaxRate software, the Advantage VSD operates with other intelligent production software to increase the uptime and reliability of ESP systems.



An upclose view of Baker Hughes' FlexPump is shown.

Borets

Founded in 1897, Borets is a key player in artificial lift systems engineering, manufacturing, sales and servicing. Having started production of electric submersible pumps (ESPs) in the early 1950s, today Borets is one of the largest ESP manufacturers worldwide. With its head office in Moscow, Russia, Borets and its 9,000 employees work in more than 24 countries, providing equipment and services to more than 500 clients, operating in nearly 42,000 wells.

According to the company website, Borets' key product lines include ESP and progressing cavity pump (PCP) systems as well as surface horizontal pumping systems designed to boost formation pressure and fluid transportation.

The company's facilities in Russia, the U.S., China and Slovakia manufacture, assemble and provide maintenance services for ESPs. From raw materials to the finished product, Borets provides traceability and quality control for each ESP system. Its ESPs are designed with flow rates of 63 bbl/d to 38,542 bbl/d and head of 328 ft to 11,500 ft.

Borets' ESPs can be deployed in challenging operating environments, including more demanding downhole conditions such as high-solids content, gas-oil ratio (GOR) and increased temperatures of produced fluids. To improve operational reliability in harsh, abrasive conditions, the company offers different pump configurations, namely compression, abrasion-resistant compression and packet assembly pumps.

In describing its manufacturing process, Borets said its ESP stages are manufactured with advanced casting techniques and powder metallurgy methods to ensure high resistance to corrosion, friction pairs wear and hydroabrasive wear.

The pumphead and base are made of high-strength steel. The heads and bases of pumps operated in aggressive well conditions are made of corrosion-resistant steel. To avoid radial wear and vibration when operating in harsh environments, pumps are fitted with radial tungsten carbide bearings.

A Sampling of Artificial Lift Providers

Company	Sucker Rod Lift (Beam Pumping)	Electrical Submersible Pumps (ESP)	Gas Lift	Hydraulic Pumping Systems	Plunger Lift	Progressive Cavity Pumps (PCP)
Accelerated Production		*	*	*		
Alnas, part of Rimera Group		*				
American Completion Tools			*		*	
Baker Hughes		*	*			*
Borets		*				*
C-Fer Technologies		*		*		*
Cameron	*			*	*	*
CAN-K Artificial Lift		*				
Dover Artificial Lift, a Dover company	*		*	*	*	*
Flotek	*	*				
Global Production Solutions		*		*		
GRC, a Sercel brand		*				
Gyrodata	*	*				
ICI Artificial Lift				*		
JJ Tech				*		
John Crane Production Solutions	*					
KUDU Pumps						*
Liberty Lift Solutions	*		*	*		
Lufkin Industries	*		*	*	*	
Novomet		*				
Patriot Artificial Lift			*		*	
PCM	*					*
Priority Artificial Lift LLC			*		*	
Robbins & Myers Energy Services Group						*
Schlumberger	*	*	*			*
Sercel-GRC	*	*				*
Sogiant Pump Jack	*					
SPOC Automation	*	*		*		*
Summit ESP		*				
Superior Energy Services			*			
Tenaris	*					*
Torqueflow-Sydex		*				*
Weatherford	*	*	*	*	*	*
Zeitecs		*				

(Source: Hart Energy)

The company offers corrosion and wear-resistant metal coatings applied to ESP housings, heads and bases that address aggressive well conditions. Increased hardness and ductility prevent these coatings from flex cracking when installing and pulling out the downhole equipment.

Borets also has developed an anti-scaling polymer coating that allows for reduced scaling and reduced corrosion of ESP components that are used in high-temperature, aggressive environments. This coating is applied to pump stages, tubes, fasteners, heads and bases to protect against scaling as well as improve corrosion, wear and chemical resistance.

In cases where ESP operating conditions limit ESP applications due to factors such as solids content, scale, high GOR, viscous fluids and low production rates, Borets offers submersible PCPs.

The company's electric submersible progressing cavity pumps (ESPCP) with permanent magnet motor (PMM) include:

- Single ESPCP;
- Twin-opposed ESPCP; and
- Twin-opposed ESPCP with fixed direction of residual thrust load.

The operating components of the PMM-PCP include a stator filled with elastomer and a steel rod. Elastomer material and clearance between the rod and stator are selected based on specific operating conditions.

Borets' R&D centers, located in Moscow and Tulsa, Okla., are engaged in the implementation of new artificial lift technologies and pump materials to aid operators in enhancing oil production.

The Tulsa R&D center is equipped with test benches for testing downhole and surface equipment and two 239-ft-deep vertical wells for testing completely assembled systems in close-to-real conditions. To test existing and new products, including high-speed motors and high-flow pumps, automated horizontal benches are used, including benches equipped to simulate pump operation in the steam-assisted gravity drainage mode (SAGD). The SAGD technology is applied for heavy-oil production when the operating temperature reaches 482 F. These advanced testing capabilities help to expand the application range and improve the quality and design of the company's manufactured equipment.

Borets' servicing network is comprised of 28 centers and 3,500 field personnel managed through Borets Service Co., operating in the main oil-producing regions in Russia (Nizhnevartovsk, Muravlenko, Nefteyugansk, Noyabrsk, Usinsk, Neftekumsk, Buzuluk, Krasnodar and the Irkutsk region) and worldwide (U.S., Canada, Brazil, Venezuela, Colombia, Egypt and Europe).

Borets Service Co. performs field trials and provides various services to enhance oil production in harsh well environments. The results of such trials are used in application engineering (ESP and PMM-PCP systems) and in developing the most efficient well operation techniques.

Dover Artificial Lift

Dover Artificial Lift is part of the Energy segment within Dover Corp., a global manufacturer with annual revenues of more than $8 billion. Formed in 2009, Dover Artificial Lift brings together artificial lift and surface production companies to deliver comprehensive solutions for optimizing oil and gas production.

Previously known as Norris Production Solutions, the company recently changed its name to Dover Artificial Lift to highlight its focus on artificial lift and reinforce its relationship with parent company Dover.

The company has been delivering artificial lift and surface production equipment for more than 125 years and has recently expanded its capabilities in artificial lift with a number of acquisitions and new products and services, said Paul Mahoney, president of Dover Artificial Lift.

Beginning with its founding company, Norris, the Dover portfolio has expanded to include a wide range of companies including Oil Lift Technology, PCS Ferguson, Spirit Global Energy Solutions, Theta Oilfield Services, Harbison-Fischer, Alberta Oil Tool, C-Tech, Pro-Rod and several others.

Over the years, strategic acquisitions armed Dover Artificial Lift with increasing expertise in various artificial lift applications. The acquisition of Oil Lift Technology in September 2011 expanded the company's reach into progressing cavity pump applications. Oil Lift Technology has more than 10 field service facilities in Canada, the U.S., Australia, Colombia and Oman.

Oil Lift recently had a debut of a Dual Ram 5000 PSI Rod-Lock BOP for shale oil and gas wells. "This joint rod-lock/BOP system provides redundant protection to reduce the risk of a blowout in high-tubing-pressure conditions," said Shane Latoski, project and operations manager.

The Rod-Lock BOP for shale wells is customizable and can include blind rams, threaded- or flanged-bottom mount, and installation of the stuffing box directly to the top mount. Larger API flanges reduce the number of components in the wellhead assembly. The BOP has a lower overall height, which allows for longer stroke length of a rod pump and results in more produced volume per stroke. The standard rod lock features eliminate the need for a rig during servicing as well as allow for the safe and secure suspension of the rodstring during servicing or to perform stroke length changes.

Dover Artificial Lift's acquisition of PCS Ferguson in 2012 expanded the company's capabilities further to include plunger lift, gas lift, nitrogen generation and wellsite automation services.

PCS Ferguson offers Well Site SCADA, a fully integrated automation solution for the well site. By collecting real-time data from each well, the system allows operators to manage by exception and best allocate limited resources.

On pad well sites, Well Site SCADA uses a single master controller to optimize and synchronize production of multiple wells and accurately allocate gas production for each. The solution's open architecture allows for integration with host systems' gas measurement solutions and other third-party devices. The system provides control of plunger-lift and gas-lift operations and also can monitor tank levels, chemical injection systems and other site facilities.

PCS Ferguson's iChem solution allows operators to take control of their chemical injection programs. The solution currently has two offerings within the family of automated chemical injection products, iChem Classic and iChem Revolution.

iChem Classic provides logical, condition-based injection control for operators seeking to control chemical costs. iChem Classic operates the chemical pump via intermittent phases and can make adjustments based on real-time conditions and data such as time, pressure, temperature, well production, plunger-lift variables and parts-per-million levels. These phases can be defined down to the second, ensuring consistent injection or user-selectable chemical volumes. Relying on solar power with a minimal footprint, iChem Classic provides low-cost, low-maintenance operation, according to the company.

The iChem Revolution product offers pump-for-volume methodology for operators that require precise injection of desired chemical amounts and frequencies. iChem Revolution can be used in retrofit applications for operators that need to manage their chemical programs by exception only and take immediate control of their chemical program costs. The amount of chemicals is delivered to within 1% accuracy of the desired chemical volumes. With remote access and report and alarm functionality, Dover noted that the need for site visits is virtually eliminated.

Spirit Global Energy Solutions, which was acquired in September 2013, added increased focus on artificial lift software and automation with the Genesis Intelligent Asset Manager. The Genesis uses artificial intelligence to ensure performance and is a platform that can be customized to the needs of a unique pumping environment. Spirit also offers training in rod pumping and pump-off control technology.

Its newest technology is the Spirit Hybrid-X Downhole Hybrid Gas/Sand/Solids Separator. This separator is designed to eliminate both gas and sands/solids pump interference from lower volume (less than 130 bbl/d to 200 bbl/d) wells. Placed below the rod pump, the separator uses cyclonic motion and internal baffling for downhole separation. It agitates and breaks apart gas-fluid emulsions and captures sand and solids in the mud joint. Sand-, solids- and gas-free production fluid fills the pump intake, permitting greater production and pump efficiency.

GE Oil & Gas

GE Oil & Gas expanded its artificial lift capabilities in July 2013 with the acquisition of Lufkin Industries. GE already was active in this sector of the oil and gas industry with its electric submersible pumps (ESPs). Lufkin's portfolio of rod lift, gas lift, plunger lift, hydraulic lift, progressing cavity pumps and an array of well controls and software added important artificial lift components.

GE's artificial lift team includes about 7,600 employees worldwide operating through a network of more than 20 global manufacturing plants and centers and 130 service centers and shops. Automation was an integral part of Lufkin's approach to artificial lift optimization. GE said that by adding this product line, it now has the building blocks that will help it develop an artificial lift "industrial Internet" through a connected network of technology, data and experts. The company's automation products are installed on thousands of wells worldwide.

One of these automation advances is the Zenith high-temperature (HT) well-monitoring technology that GE integrated after the Lufkin purchase. The Zenith technology, which was compatible with GE's existing ESP offerings, recently surpassed 1,000 operating days in wells with temperatures up to 500 F. With the ability to survive hostile conditions for longer periods and at higher temperatures than alternative tools, the company said the Zenith HT gauges have proved their reliability.

The gauges were installed in "huff and puff" EOR wells in August 2010 and have been in continuous operation since that time. Additional Zenith HT gauges were installed throughout 2012 in various well environments, including ESP, steamflood operations (recorded up to 421 F), rod pump and observation wells (104 F to 442 F).

GE's artificial lift team includes about 7,600 employees worldwide operating through a network of more than 20 global manufacturing plants and centers and 130 service centers and shops.

"The proven survivability and long-term reliability of our Zenith HT gauge is having a significant impact on artificial lift operations as we help [operators] go into hotter and deeper locations," said Greg Davie, general manager of Zenith products, in a press release. The introduction of this technology that performs in these hot environments is unlocking improved production and reservoir drainage, Davie said.

Another Zenith product was recognized as an innovative technology at the 2014 Offshore Technology Conference in Houston. Honored with the Spotlight on New Technology Award, GE's Zenith GFI (Ground Fault Immune) ESP Monitoring System was cited for its effectiveness in monitoring an ESP pump when a ground fault occurs on the ESP power cable. Under normal circumstances, a conventional monitoring system's gauge would be cut off after a ground fault, and the performance of the pump would no longer be monitored.

The Zenith GFI solution includes a new power and communications system that enables the gauge to operate with imperfect insulation on the ESP cable and avoid the interruption of cable ground faults. According to the company, the new system also provides faster data sampling than alternative gauges and delivers ESP cable condition measurements in addition to standard industry parameters.

"All too often in ESP operations, a ground fault will cause downhole monitoring systems to fail and leave operators running blind," said Dave Shanks, development manager for GE's Zenith technologies. "This can result in up to a 25% reduction in fluid output when compared to a pump optimized with a live downhole gauge, resulting in a significant loss of production. Our Ground Fault Immune gauge offers a monitoring solution that is designed not to be disturbed by these types of faults for the first time."

To help further this type of innovation in artificial lift, the company signed a new technology collaboration agreement (TCA) with Devon Energy Corp. in May 2014. Under the agreement, GE will collaborate with Devon on advancing innovation in artificial lift technologies, along with new drilling technologies and water treatment and processing to reduce water use and better utilize water resources.

GE has supplied artificial lift systems to Devon for many years.

The TCA was announced at the groundbreaking for GE's new Oil & Gas Technology Center in Oklahoma City. The $125 million center, which will open in third-quarter 2015, will create 130 high-tech jobs. Scientists at the hub will focus on developing advanced artificial lift pumps; well designs with a smaller environmental footprint; and technologies for CO_2 capture, transportation and storage.

The 100,000-sq-ft Oklahoma hub will join a global network of seven other GE research centers located in India, China, Germany, Brazil and the U.S. The company has invested $14 billion in the oil and gas business since 2007 and plans to triple its R&D spending in the sector during the next three years.

John Crane

John Crane Production Solutions (JCPS) is part of John Crane, the largest division of Smiths Group Plc and a global provider of engineered products and services. John Crane provides customized solutions across a product portfolio ranging from mechanical seals, filtration systems and bearings to couplings and artificial lift equipment.

JCPS specializes in artificial lift equipment and services for upstream oil and gas production. Drawing on nearly 100 years of experience, the company offers design, manufacturing, installation, commissioning, service and repair of API and non-API rod pumps, an automated prime mover (APM), fiberglass sucker rods (FSR), and API and high-strength steel sucker rod products for artificial lift systems.

The APM GEN III is a new clutched, timed, drop-in engine assembly that can be easily installed on a conventional pumping unit operating on both wellhead gas and propane. The APM has an easy-to-use controller that allows for ultimate flexibility and adaptation to oilfield operating environments ranging from those in West Texas to North Dakota, according to the company. The Environmental Protection Agency Quad J certified engine has many options that allow for remote monitoring and operations in remote locations.

John Crane said its JCPS FSR is proven technology that is used today in a full range of operating environments. It enables the operator to decrease capex and opex due to the lightweight and corrosive-resistant nature of the product. The high-temperature Fiberod FSR is the newest design used for upstream oil production in shale fields where operators work in extreme high temperatures. This technology evolved from the original lightweight fiberglass rod introduced more than 20 years ago and is now used in many of the world's largest oil fields. The high-temperature rod provides an energy-efficient option for use in difficult conditions, where operators previously used heavy and more costly pumping units.

In a press release announcing the introduction of the new high-temperature FSR, Duncan Gillis, president and CEO of John Crane, said, "Shale fields will continue to be a significant and viable energy source used to meet growing energy demands. We developed this new technology so the extreme temperatures that can be found in shale field production would not be a barrier to entry ... In addition to meeting [the] requirements for reliability, the new rod will meet expectations for environmental management practices."

John Cranes' FSRs' advantages include their lightweight and corrosive-resistant nature. *(Image courtesy of John Crane)*

The company's line of API and high-strength steel sucker rods and accessories is available in a variety of grades for different applications. The sucker rods are available in 25-ft and 30-ft rod lengths. Along with the steel sucker rods, JCPS also provides a full line of API and non-API downhole pumps.

National Oilwell Varco

National Oilwell Varco (NOV) has a long history of providing artificial lift equipment for the oil and gas industry. Offering hydraulic rod pumps, progressing cavity pumps (PCPs), plunger lift and automation, and control and monitoring, NOV brings a variety of artificial lift solutions to the industry.

NOV Plunger Lift technology is used to dewater liquid-loading gas wells that have marginal production, in wells with a high gas-oil ratio, in wells that currently are being soaped, and for paraffin and hydrate control.

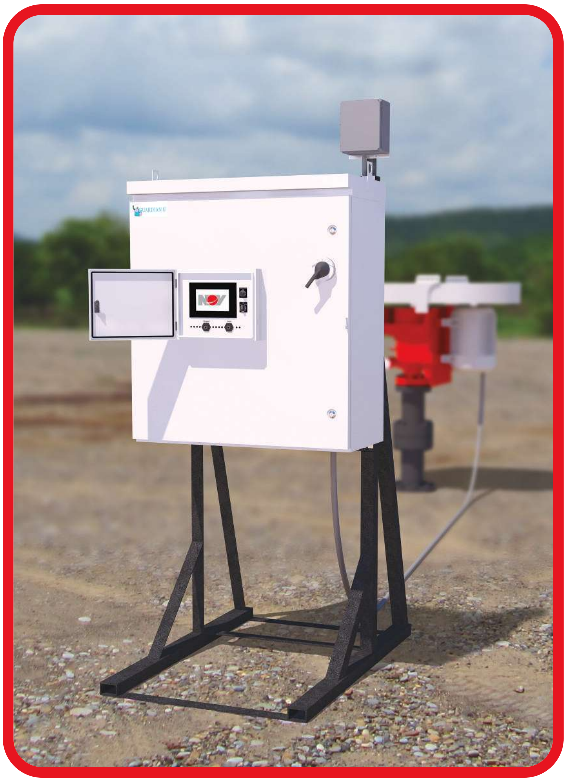
NOV's PCPs are designed for use in both oil production and dewatering applications where the economics of production demand efficiency, reliability and low life-cycle cost from the production equipment.

NOV rod pumping systems can be used in many oil and gas applications. The company's innovations in pump solutions and automation controls have concentrated on increasing efficiency, achieving longer mean time between failures and better control functions by using a smaller footprint, quick installation time and the ability to adjust stroke speed and length.

Using artificial intelligence for artificial lift brings operators a solution that NOV calls "a new 24/7 production partner," which is its full line of pump controllers and variable frequency drives (VFD).

The Guardian II Rod Pump Controller comes automatically integrated with each Guardian II VFD. The Guardian II connects to a standard alternating current (AC) motor and does not require additional external hardware or interfaces except an inexpensive arm position sensor.

By automatically adjusting the pump speed to accommodate changing conditions downhole, the Guardian II Rod Pump Controller provides an advanced solution to prevent pump-off. On each stroke, the rod pump controller automatically optimizes performance by matching the pump speed to the fluid inflow of the well.



NOV's Guardian II system connects to a standard AC motor and does not require additional external hardware or interfaces except an inexpensive arm position sensor. *(Image courtesy of NOV)*

NOV said improved pump efficiency provides cost savings because of the maximum pump fill at each stroke. In addition, the energy that is generated during the downstroke operation is captured and fed back into the mains, producing energy savings of 30% over classic rod pump installations, according to NOV. No special braking resistors or hardware are required since they come built in on the Guardian II VFD. The Guardian II controller also is available for PCPs.

NOV Guardian OnSite provides a suite of software and services that gives field operators the ability to monitor and manage key aspects of all pumps deployed, and a responsible party or group can be notified by email or text if problems occur.

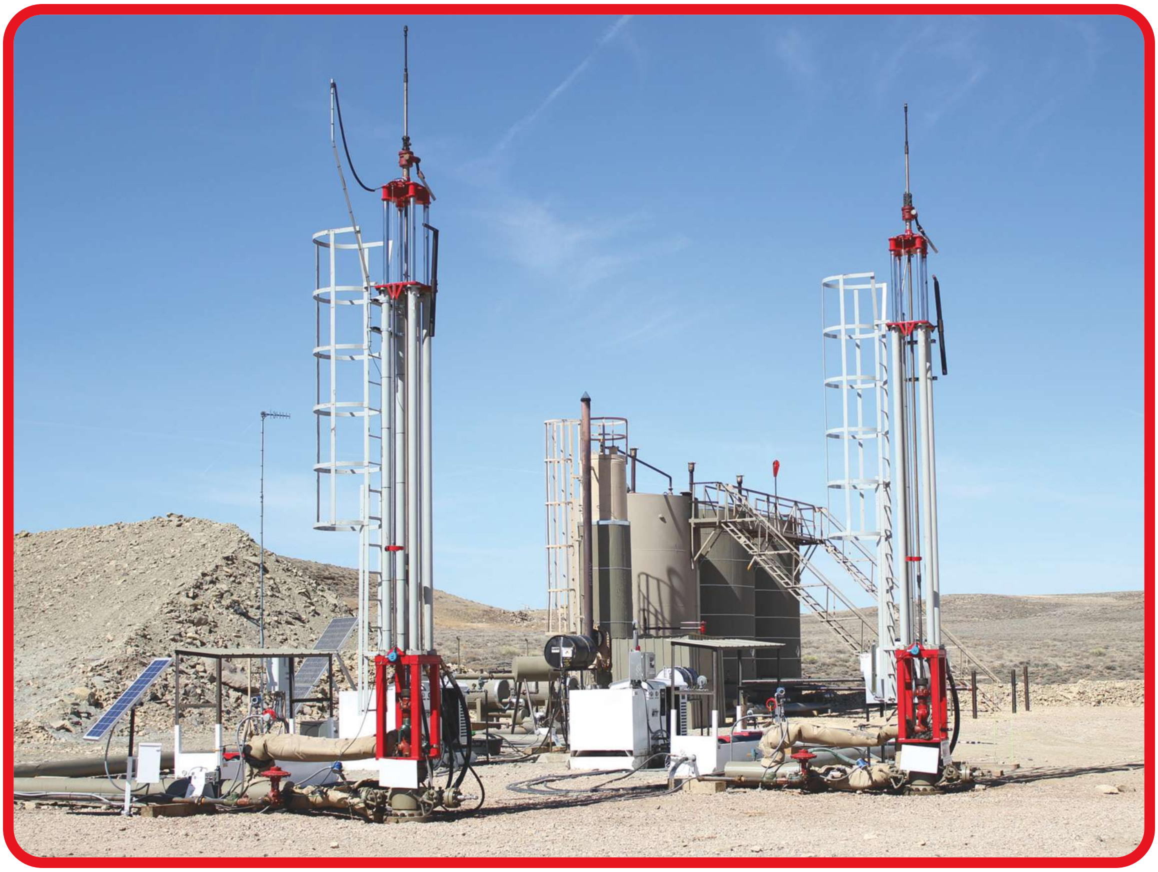
Guardian OnSite keeps a central repository of detailed performance information collected over an extended time frame. This allows engineers and operators to review operational efficiencies and locate trends to predict problems or to analyze the effectiveness of changes made to a pump's operating parameters. Besides retaining and retrieving long-term performance data, Guardian OnSite provides a real-time view of all monitored pumps.

Data are collected via a variety of methods including serial MODBUS, serial MODBUS over data radios, MODBUS over Transmission Control Protocol/Internet Protocol and MODBUS over satellite.

The company said optional cameras can be added to the monitoring service to help diagnose faults without having to visit the site and to help assure that site safety and environmental procedures are being applied.

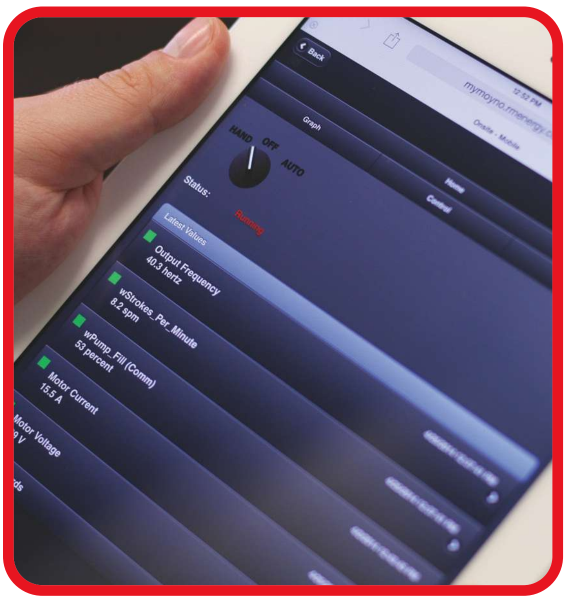
Guardian II can be implemented into existing SCADA networks. If required, it can adapt its setup to appear as any type of legacy system currently implemented, which reduces the effort required to configure backend systems for PCP monitoring and control.

Guardian CommunicateNow is a hardware and software service that provides communication systems for transmitting performance information or for stopping, starting and adjusting operating parameters in real-time or near-real-time operating modes. By using satellite technology, NOV can provide monitoring and control services to an operator's computer without any additional infrastructure buildout.



NOV's intelligent equipment alleviates the need for costly site visits. *(Images courtesy of NOV)*

NOV's downhole and surface sensor systems can be integrated with the Guardian II system. The systems also can be integrated by using built-in input terminals that can interface with virtually any system currently available.



Pump performance can be constantly monitored via NOV's intelligent artificial lift systems.

The Downhole Monitoring System consists of a digital electronic pressure and temperature gauge that is run into the well with the PCP completion string. A conductor cable is attached to the gauge to continuously transmit the data to the surface. The cable is attached to the tubing string during run-in operations of the pump, with protectors at each collar to protect it from wear.

When downhole systems are not required or when PCPs are used for surface pumping systems, NOV can provide flow sensors to monitor pump performance and provide pump-off control. With either downhole or surface systems NOV can provide everything necessary to maximize pump runlife and automatic pump optimization with minimal operator intervention, according to the company.

Schlumberger Ltd.

Schlumberger's artificial lift solutions feature REDA electric submersible pumps (ESPs) and Camco gas-lift and subsurface safety systems integrated with real-time reservoir monitoring, round-the-clock surveillance and diagnostics to enhance lift system performance and eliminate potential problems.

The REDA ESP systems can be used in a range of artificial lift applications from cool-water wells and gas well dewatering systems to high-pressure conditions and high-temperature pumping systems.

The Schlumberger REDA Hotline high-temperature ESP systems are geared for high-temperature, highly abrasive and corrosive environments. With the ability to handle the temperature differentials between the surface and downhole operating temperatures, these systems have been installed more than 1,400 times in 450 active wells worldwide.

Introduced in 2011, Schlumberger's third-generation REDA HotlineSA3 high-temperature ESP system is designed specifically for steam-assisted recovery operations and geothermal applications.

In a press release announcing the new ESP system, Gus Melbourne, president of Schlumberger Artificial Lift, said, "The REDA HotlineSA3 system can reliably produce from wells with bottomhole temperatures of up to 250 C [482 F]. This enables the installation of the ESP at the earliest stages of the development of the steam-assisted gravity drainage [SAGD] chamber, when pressure and temperature are highest. The ability to monitor winding temperature directly and in real time gives operators control of the REDA HotlineSA3 system during unexpected production instabilities without increasing the risks of exceeding system capabilities."

Schlumberger said the system passed extensive testing while running at maximum-rated temperatures. This included strict third-party qualification requirements at C-FER Technology laboratories in Canada, with collaboration and sponsorship by major heavy-oil operator ConocoPhillips. The system underwent extensive field testing in SAGD fields in Canada and steam-flood fields in Oman.

According to a description of the HotlineSA3, the system includes a multifunction integrated motor unit, thermally compensated pumps, downhole monitoring gauges for pressure and temperature, power cables and a surface controller. The purpose-designed plug-in, high-temperature motor lead extension has a dual elastomeric seal, and the motor electrical port connection has a positive pressure system that works to prevent fluids from escaping or entering the motor during connection. The integrated motor uses special, high-temperature materials rated to 572 F and is factory filled with specially treated, ultradehydrated dielectric oil.

Another one of the company's ESP systems is the REDA Maximus ESP system, which uses the MaxJoint ESP flange connection technology. The system features a MaxLok ESP quick-plug motor lead connector that ensures a leak-tight connection and eliminates the process of taping in the pothead terminals at the well site.

The company's REDA Coil ESP system allows an ESP to be deployed using standard coiled tubing, eliminating the need for a workover rig and surface equipment. This deployment method is especially beneficial in offshore and deepwater applications.

For more commonly encountered well environments, Schlumberger offers the EZLine low-temperature ESP system. With a basic, field-proven conventional design, the EZLine ESP system offers a range of flow and head configurations. Upgrade options are offered for more difficult applications including customization for more resilience to corrosion, abrasion and solids.

Schlumberger also offers its Camco gas-lift systems, which include injection-pressure-operated and production-pressure-operated models as artificial lift solutions. Conventional waterflood flow regulator valves and mandrels are available for single- and dual-string installations.

All of these valves have a variety of port sizes, offering a range of selected gas-injection volumes and flow rates. Most have floating valve seats that allow the choke size to be changed in a stock valve, which simplifies valve repair and improves sealing capability.

The Camco valves use reverse-flow check valves to prevent reverse flow and the commingling of production fluids in gas-lift installations.

Schlumberger offers three different real-time downhole monitoring systems: the Phoenix xt150 system, the Endurant ground-fault-immune system engineered for high-temperature environments for ESPs, and the Phoenix CTS (cable-to-surface) system.

The Phoenix xt150 and the Endurant systems monitor downhole pressure, temperature, current leakage and vibration and provide comprehensive data needed to protect ESP system integrity and optimize well performance.

These systems communicate with the surface through the ESP motor cable. The electrical system has a tolerance for high phase imbalance and the capacity to handle voltage spikes. Additionally, the Endurant system is designed to continue operating and transmitting measurements, even if a ground fault occurs. Designed with metal-to-metal Inconel transducers, a stainless steel body and high-temperature circuitry, Schlumberger said the Endurant system can operate continuously and reliably in temperatures up to 302 F. The Endurant monitoring system operates with a dual power supply, which prevents the gauge breakdown caused by ground faults so it can continue communicating to the surface without interruption.

Both systems measure intake pressure and temperature, motor oil or motor-winding temperature, vibration and current leakage. The ESP monitoring systems also can measure pump discharge pressure, which is used in evaluating pump performance.

The Phoenix CTS system features advanced downhole sensors for gas-lift, sucker-rod pump and progressing cavity pumping wells. This system acquires pressure, temperature and vibration measurements for in-depth identification, diagnostics and analysis of equipment operating problems and changes in reservoir conditions.

Multiple sensors mounted on the production tubing either above or below the artificial lift equip-

ment collect and transmit data to the surface via an independent encapsulated instrument cable.

All of these downhole monitoring systems use either the UniConn universal site controller or the Instruct all-in-one acquisition and control unit to provide remote access and control from a single platform. The data can be further integrated with the Schlumberger LiftWatcher real-time surveillance and optimization service for 24-hour surveillance of all monitored parameters via satellite.

Both control systems are SCADA ready and have a MODBUS protocol terminal with RS232 and RS485 ports for continuous data output.

Weatherford International

Weatherford offers a wide variety of artificial lift solutions, including gas-lift, plunger-lift, progressing cavity pumping (PCP), rod-pump and hybrid-lift technologies as well as solutions for electric submersible pump (ESP) applications.

The company seeks to reduce workover costs by implementing intelligent wellsite equipment to increase the runlife of the well. Also, electrical and chemical costs are reduced by optimization of the lift equipment.

The Weatherford total optimization solution for ESP combines intelligent control at the wellhead through wellsite intelligence, historical references and remote optimization as well as monitoring, analysis and control at the desktop.

The company's intelligent controller provides 24-hour wellsite control and optimization. The controller interacts with downhole sensors and surface instruments to measure conditions and control the well operation. This controller comes programmed with templates to allow control of the startup and speed of an ESP. All information is

based on the input received from the downhole sensors, motor controller and other equipment at the well site.

Weatherford WellFlo ESP software contains a complete database of pump performance curves for all the models from leading ESP manufacturers. These performance curves are used as the basis for the head calculations, which are then adjusted for fluid density, pump frequency, number of stages and other system variables.

Weatherford McMurry-Macco gas-lift systems feature a range of compatible equipment and capabilities to complement every gas-lift design.

The company's WellTracer gas-lift surveillance technology can give operators a quick determination of a gas-lift injection point as well as unwanted entry points without shutting down operations. In this procedure, a small amount of CO_2 is injected into the gas supply flowing down the casing. As this concentration of CO_2 returns through the wellhead tree, flowline or well test separator, the sensor detects its presence.

WellTracer technology uses this detection to identify the various lift points, the depth of the operating valve(s) and even injection gas leaks into the production tubing for a snapshot of the well's performance. Trace return times are 1 hr to 7 hrs.

Weatherford hydraulic-lift systems offer both jet and piston hydraulic-lift systems ranging from operating depths of 0 ft to 20,000 ft with volumes from 10 bbl/d to 35,000 bbl/d of fluid.

The hydraulic-lift systems include a surface package and either a downhole jet or reciprocating piston pump. While the jet pump has no moving parts, which makes repair cost negligible, both classes of pumps operate multiple wells from a single package. A major advantage to either system is the ability to hydraulically circulate the pumps to the surface for maintenance.

By combining and exploiting traditional artificial lift technologies across platforms, Weatherford extends lift applications, allowing them to perform better with improved efficiency and economics. The benefits of this cross-pollination of systems and technologies make current systems more adaptable to a multitude of downhole conditions.

Hybrid-lift systems available from the company include:

- **CP-Gas Lift Combination.** This integrated hybrid system combines the volumetric efficiency and heavy crude oil handling capabilities of PCP with the fluid head reduction ability of gas lift. Typically, lift gas is injected above the PCP, causing the fluid head to be reduced significantly, thus increasing the performance of the PCP. According to Weatherford, the liquid head can be reduced by up to 40% in some cases.
- **ESP-Gas Lift Combinations**. In this cross-pollinated system, Weatherford is able to combine the high-volume lift capability of an operator's ESPs with the liquid head reduction capabilities of gas lift. Lift gas is injected above the ESP to lower the density of the fluid head. Again, the company has seen head reduction of up to 40% of total head, vastly improving the performance capabilities of the ESP.
- **Jet Pump-Gas Lift Combination.** The reservoir drawdown capabilities of the jet pump combine with the fluid head reduction capabilities of gas lift to form this integrated system. Typically, concentric tubing such as coiled tubing is installed inside the production tubing with a jet pump installed on bottom. Power fluid is injected down the concentric string where well fluids mix with the power fluid through the jet pump and are produced up the production tubing. Lift gas is injected above the jet pump, reducing the liquid head and increasing the efficiency of the system.
- **Gas Lift-Plunger Lift Combination.** In this integrated hybrid system, Weatherford combines a plunger with gas lift to increase lifting efficiency in intermittent lift wells. In many deep intermittent gas-lift installations, the lift gas breaks through the liquid slug before the slug leaches to the surface, resulting in substantial lift fallback. Lift efficiency can be increased significantly by combining a plunger to form an interface between the lift gas and fluid slug. The plunger provides a better seal between the lift gas and liquid slug as it travels to the surface, increasing efficiency and produced fluid recovery. ■

Surviving the Renaissance

As horizontal wells mature in the U.S., operators will need to determine the best forms of artificial lift for maximum production.

By Hart Energy Staff

The unprecedented growth of the hydraulic fracturing industry in the U.S. has led to an energy renaissance for the country. But as the predominantly horizontal wells begin to mature, one basic concern arises: how to continue producing the wells to their fullest extent.

To answer this call, there are several forms of artificial lift that have proven successful in unconventional plays, and depending on the type of hydrocarbon being produced, there are numerous recommendations for optimizing the well's lifespan.

"Right now we have identified more than 17 different kinds of artificial lift systems used for producing gas wells and quite a few for producing oil wells, too," said Cleon Dunham, director of the Artificial Lift R&D Council. "The types of artificial lift that are used are a function of many factors including the size of the hole, what size your casing is, what size your tubing is, what your wellbore trajectory is, what experience people have in that area and what support services are available."

Whether producing gas, oil or condensate, artificial lift is used to increase pressure within the reservoir and assist the hydrocarbons to the surface. While there are several varieties of lift available, there are seven basic types from which all others are derived:

- Electric submersible pumps (ESPs);
- Sucker-rod lift;
- Plunger lift;
- Gas lift;
- Chemical lift;
- Progressive cavity pumps (PCPs); and
- Hydraulic pumping systems.

ESPs

Traditionally, ESPs have been brought in to enhance oil production as soon as it begins to decline and while there is still a moderate to high volume of fluid that can be lifted from the well. This fluid could be crude oil or brine, or it can be another form of liquid or gas such as disposal injection fluids, liquid petroleum products, CO_2 or H_2S gases, and even certain solids or contaminates.

An ESP comprises a multistaged centrifugal pump, a three-phase induction motor, a seal-chamber section, a power cable and surface controls. These components hang in tubing that runs beneath the low-profile surface pump, which also makes this a more aesthetic choice of lift, and they attach to the motor, which most often is deposited at the end of the vertical section of the well. When turned on, impellers along the ESP's shaft will spin and force the fluid in the wellbore to rise to the surface.

Standard ESPs can produce anywhere from about 150 bbl/d to 30,000 bbl/d or possibly more if they are equipped with a variable-speed controller that can help extend the range higher or lower as needed. This makes them ideal for wells with low API gravity fluids, a low gas-oil ratio (GOR) or a high water cut.

"The advantage of ESP is you've got an electrical cable that's going downhole to run the lift motor. You can use that cable to transmit signals from instrumentation placed at the bottom of the well that will measure the pump intake pressures, the intake temperature, the motor-winding temperature, the unit vibration and a few other things," Dunham said. "That information can be used to not only monitor the well but to see if there are problems and to control them before they become real issues and interrupt production."

This capability has made ESP a cost-effective option for many operators, said Bill Vaught, director of global business development and marketing for the Baker Hughes Artificial Lift Services group. ESP is one of the primary forms of artificial lift offered by the company. However, he said there are a few things to watch out for in unconventional onshore wells.

"As you draw the well down you find that the well typically has a high amount of gas, and so the ability to either avoid that gas or handle that gas or compress the gas in the well is something we've been working on quite heavily; it's a challenge in some of these unconventional wells," he said. "The other challenge we're faced with is getting the system through the bend. An ESP can be a very long system, and if you don't have the proper equipment for setting that up through a very tight bend, you can damage it going into the well."

Repairing a damaged ESP system can be very costly, said Greg Nutter, vice president of operations and HSEQ for AccessESP. In some cases, such as when the rig is located offshore or when there are permitting issues or issues with rig availability or accessibility, a rigless ESP offers a more cost-efficient solution.

"If you have to change your ESP every six months and bring a rig out there in an offshore location, it could be a $5 million proposition just to change out the ESP," he said. "The whole time it's not working, you're also not making production, so every day you have zero on your production, it is costing $100,000 to $1 million a day. Then you are going to have to spend that $5 million to $10 million in operating expenses to call out a rig and get the ESP pulled out of the ground and get a new pump back in the ground. With rigless ESP, instead of waiting up to six months to do this, it can be replaced in a few weeks—sometimes in as little as one week."

After its initial installation, rigless ESP can be deployed with a slickline, wireline or coiled tubing unit, he said, which might be easier to mobilize depending on the location of the well.

Sucker-rod lift

The pump jack, the horsehead beam and crank assemblies rocking back and forth to produce the energy needed to operate sucker-rod artificial lift systems are common sights in the oil patch. Sucker-rod lift is one of the oldest forms of artificial lift in the world, known for its ability to aid in reducing bottomhole pressures (BHP) to very low levels. In the U.S., about 350,000 wells have sucker-rod pumps. Those wells are primarily onshore because the weight and space requirement of a sucker rod's surface pumping unit is not practical for offshore rigs.

Sucker-rod pumping systems offer greater flexibility for achieving low-to-medium production rates than other forms of lift such as ESP and hydraulic. The simple design and easy maintenance of the rod-lift components and the fact that this form of lift has been used for several decades, make it less challenging to find people who know how to work the systems. Also, surface and downhole equipment tends to retain its value because of its simplicity in design, which makes it easier to refurbish.

This cutaway shot shows the inner workings of AccessESP's slickline conveyance solution for rigless ESPs. *(Image courtesy of AccessESP)*

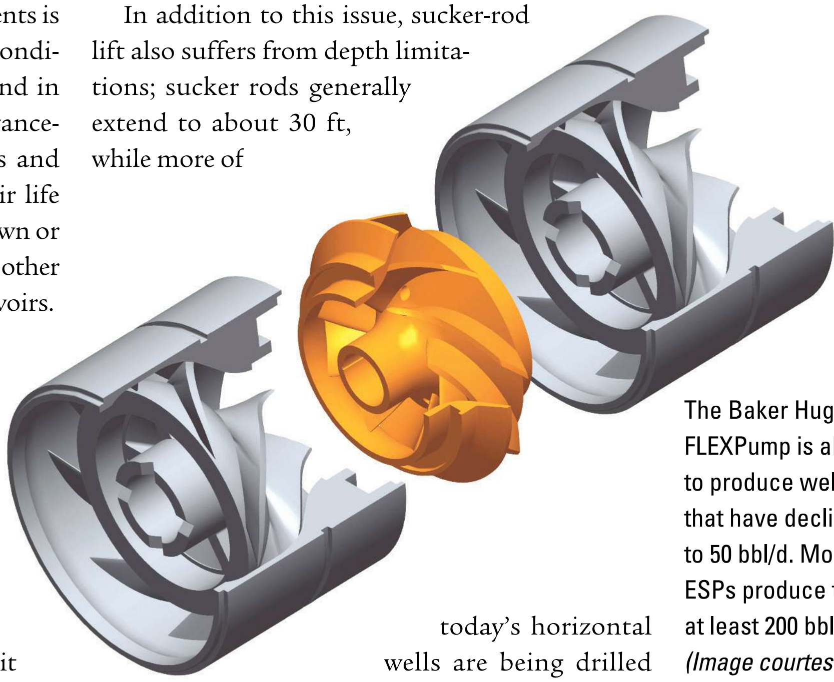
Another benefit to sucker-rod lift components is their resilience to a number of operating conditions such as the HP/HT environments found in many of the horizontal wells in the U.S. Advancements in the metallurgy of the sucker rods and their components are helping to extend their life and reduce the incidence of their breaking down or becoming overly caked with paraffin, scale and other inhibitors common in unconventional reservoirs.

A sucker-rod pumping system comprises a prime mover to power the system, a gear reducer to adjust the speed of the prime mover to the optimal pumping speed, a pumping unit to take the rotating motion of the gear reducer and prime mover and translate it into a reciprocating motion, a sucker-rod string (located inside the production tubing) that transmits the reciprocating motion of the pumping unit to the subsurface pump, and the subsurface pump itself. Other parts exist as well, such as a stuffing box located just above the surface—used with a polished rod to ensure a liquid seal remains consistent at the surface—and of course the beam pumping system that supplies the constant energy needed by the prime mover to keep the sucker rod moving.

Very simply, the surface unit transfers the energy from the prime mover to the sucker-rod string. Then the prime mover, with help from the gear reducer, adjusts the speed so it is suitable for the rotary motion of the sucker rod. The sucker rod has to remain vertical to ensure there is no bearing movement applied to the sucker-rod string above the stuffing box, which in turn ensures the liquid seal remains intact. As the rod turns, the subsurface pump, which is installed as part of the tubing string near the bottom of the well, drives the oil up through the well until it can be collected at the surface.

While this is highly effective in vertical wells, it becomes more of a problem in horizontal wells where it is difficult to place the subsurface pump in a position where it can effectively pump the hydrocarbons around the bend, getting the oil, gas or condensate in the lateral section to move efficiently up through the vertical section to where it can be harnessed at the surface.

In addition to this issue, sucker-rod lift also suffers from depth limitations; sucker rods generally extend to about 30 ft, while more of today's horizontal wells are being drilled deeper than before. However, the relatively new development of long-stroke pumping units has helped to lessen the impact of this particular detractor.



The Baker Hughes FLEXPump is able to produce wells that have declined to 50 bbl/d. Most ESPs produce to at least 200 bbl/d. *(Image courtesy of Baker Hughes)*

Dunham said other issues that would prevent operators from using sucker-rod artificial lift for their mature wells include too much sand, too-heavy oil or oil that is too viscous, or if the well is producing too much gas. However, he said the pros outweigh the cons.

"I think we have good technology, good automation systems and lots of companies that provide [sucker-rod] equipment and know-how to operate it," Dunham said. "If you have to put a well on an artificial lift system, use sucker-rod pumping unless you can't."

Plunger lift

While sucker-rod pumping is common, plunger lift isn't far behind in popularity. As one of the least expensive and least impactful artificial lift applications on the environment, plunger lift has its own following, said James Bracken, U.S. business unit manager for capillary, plunger and gas well automation at Weatherford.

Of course, there is no set rule stating which type of lift is better than another because it depends on many factors such as the weather and the type of well and reservoir, he said. However, plunger lift can be used in gas wells, oil wells and gas-lift wells, and it will operate in a similar way across the board, making it easier to find mechanics and other professionals that know how to use it and maintain it.

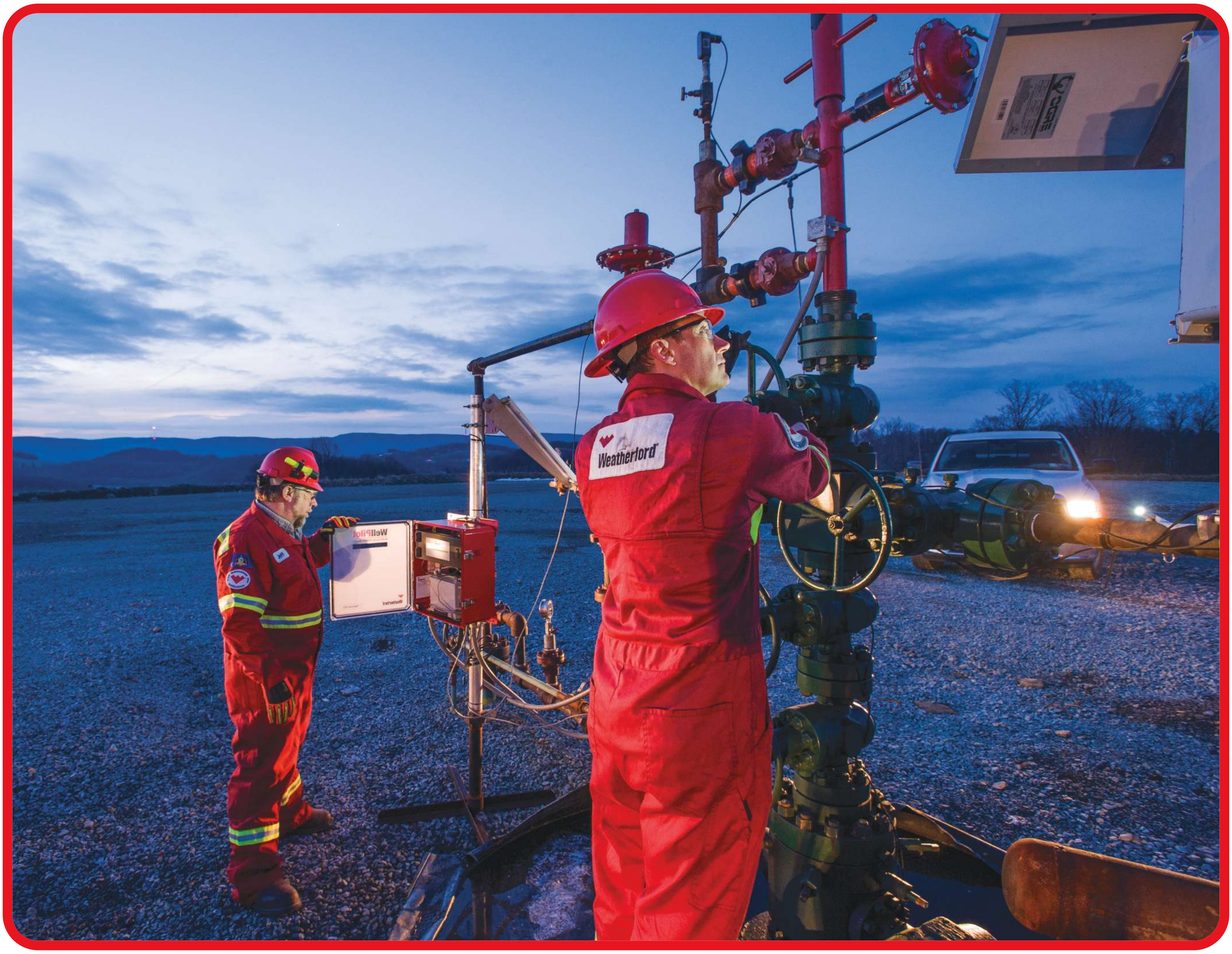
Plunger lift uses a piston, which is the length of steel also known as the plunger, to pump liquids from the wellbore. The piston travels up and down the well's tubing string at the velocity that best allows it to minimize gas slippage at the pump.

In addition to reducing gas slippage, plunger lift also limits liquid loss and uses the energy created by its piston to more efficiently increase production. It's considered an efficient system because the plunger uses the well's own energy to effectively form a seal—just like a plunger from a hardware store would do—to pull the liquid and the gas to the surface through natural suction.

"When [the plunger] gets to the surface you want to hold it there as long as the gas flow rate stays good," Dunham said. "When the gas flow rate starts to decline, you drop the plunger to the bottom and then start the cycle again. There are several different kinds of plungers, and there's a difference in cost, a difference in reliability and so forth. The operator has to choose the plunger that makes the most sense for his particular operation."

One of the trends Bracken said he is seeing at Weatherford is a drive toward more environmentally friendly solutions, which has generated a lot of business for plunger-lift systems. But as Dunham said, not all plunger-lift systems and components are created equal.

A plunger and automation installation is completed in the Northeast. *(Image courtesy of Weatherford)*



"Mostly you're going to look at the well geometry—what size casing, what size tubing, the pressures that are associated with it such as bottomhole pressure, static bottomhole pressure, your line pressure at the surface, etc.," Bracken said. "Your well temperature comes into play because that helps you decide whatever it is you're going to run; whether it's a metal geometric cap string or the type of rods or a metallurgical gas valve. Each form of lift operates best within a specific gas or liquid ratio or oil ratio."

Plunger-lift systems are used on wells that have a high gas or liquid ratio. Dunham said the main drawback of the plunger-lift systems is that they are limited in the amount of gas they can help produce from a well. However, when low line pressures or compression are combined with this form of artificial lift, several types of wells might be produced until the BHP is too low to lift the plunger to the surface.

Gas lift

Gas lift can be one of the most effective forms of lift for getting maximum production out of mature, horizontal wells, Dunham said.

"Gas lift works well in high gas-to-oil or high gas-to-liquid ratios that may be problematic in other forms of lift, such as positive displacement pumps," said Mark Laine, U.S. business unit manager for gas lift systems at Weatherford. "The general fit for gas lift would be formation gas-to-liquid ratios above 500 standard cubic feet per barrel and liquid rates above 75 barrels per day."

For this form of artificial lift, high-pressure (HP) gas is injected downhole to reduce the density and viscosity of the well fluids. Bubbles are formed in the liquid by the gas, and they work to help lower the BHP and drive the hydrocarbons up for production.

There are two types of gas lift employed today: continuous and intermittent flow. Continuous flow is the most popular type because it is especially effective in waterflood reservoirs or formations with high GORs. It also is frequently used offshore and on wells with high volume and BHP. As the name implies, this type of gas lift requires the gas to be injected continuously down a conduit. As it mixes with the well's fluid, the flowing pressure diminishes and the flowing BHP is reduced below the static BHP, allowing the fluid to flow more easily into the wellbore where the bubbles can then assist it to the top.

Intermittent flow is the periodic displacement of liquid from the well by the injection of HP gas. It is a popular choice when the well has been depleted to its lower rates and even when those low-production rates are hindered by liquid loading.

This form of gas lift is less common in unconventional plays because of the significant presence of sand used as proppant for fracking the shale; the intermittent BHP usually can't be tolerated by wells that produce sand. It is most commonly used when the flowing BHP is low and when the gas is lifting the hydrocarbons from a bottom valve. Continuous-flow gas produces at a much higher rate, making it the preferred choice among the two whenever possible.

Dunham said the three main objectives of gas-lift oil wells are to inject the gas as deep as possible, to inject it in as stable a manner as possible and to inject it at the optimum rate.

"A lot of people talk about gas optimization, and I say, 'Don't talk to me about gas optimization until after you're deep and stable because until then it doesn't make sense,'" he said. "So our goal is to design the valves and the spacing and inject the gas at the rate needed to get deep, stable and optimum."

Using gas lift on a gas well is a different situation all together, Dunham said.

"We're trying to inject enough gas so that the total gas rate—the produced gas plus the injected gas—is enough to maintain what we call critical velocity, which is the velocity needed to keep the liquid lifted out of the well," he said. "In gas wells, we like to get the gas injection as deep as possible and sometimes often even below the packer and down across the perforated interval to keep that whole vertical area—or horizontal area as the case may be—swept free of liquid so that the gas can flow most efficiently."

Chemical lift

Chemical lift also is a popular choice of lift for gas wells, Dunham said.

"There are three main choices for chemical lift," he said. "They include dropping soap sticks, injecting chemicals in batches down the annulus or using a capillary tube to inject the gas continuously down to the bottom of the well. There are also different strategies for chemical injection, and some people are using chemicals with plungers, chemicals with gas lift and all kinds of different combinations."

As production declines in a gas field, the drop in BHP will make it difficult to carry liquids to the surface. This is called liquid loading. The creation of more free fluids in a well will produce more backpressure on the formation that could damage it in the long run. Chemical lift is a method used to remove liquids from gas wells when liquid loading begins to occur.

surface. This form of lift requires only one chemical pump, one chemical storage tank and a secondary containment for the chemical tank. It can be used alone or with other forms of lift such as plunger and gas. Foamers also can serve a dual purpose by acting as surfactants for corrosion, scale, paraffin and salt deposition as they lift fluids to the surface.

When a large volume of foamer is injected downhole in a batch it can be left to perform its chemical lift for a time until its performance begins to decline. At that time, another batch can be sent downhole. Foamer also can be pumped continuously downhole in smaller volumes rather than batches. In either case, it's important for there to be regular monitoring to ensure optimization of this form of lift.

As companies continue to expand into unconventional territories, there will be a call for new and improved technologies in artificial lift.

Soap sticks are an inexpensive means for turning the produced water into a mist that will lift easier to the surface with an up-flowing gas stream. One soap stick can effectively treat 1 bbl of water. Once it is dropped downhole, it encounters the column of produced water where gas bubbles already are churning toward the surface. The stick will dissolve when it encounters this activity. As the mist rises from the chemical reaction of the soap stick, the pressure downhole is likely to be relieved enough to where it can burp up an additional amount of water, usually unloading a total of 1 bbl to 5 bbl of water per soap stick. While this is the least expensive method of artificial lift on the market, it is only able to remove about 50 bbl/d to 100 bbl/d of fluid from a gas well.

Another form of chemical lift involves using foaming agents (foamers) that are lower in density than the liquids in the gas well. As Dunham mentioned, foamers can be applied to a gas well continuously or in batches.

As the foamers are agitated by the gas flow, their bubble film holds the liquids and lifts them to the

PCPs

Use of PCPs is most common in Canada, but because this form of artificial lift is one of the more economical options, its popularity is spreading throughout the U.S. and worldwide.

Similar to a piston pump because of its sealed cavities and its ability to use positive displacement to pump at very low rates, a PCP can work at any deviation angle in a well. This means providing artificial lift for horizontal wells is not a challenge for this pump. What is a challenge, however, is the PCP's inability to function well in high temperatures; it can only work in a maximum of 350 F. That can be a major issue for many of today's horizontal wells.

A PCP consists of a helical steel rotor and a stator that comprises metal tubing with internal molded cavities that match the helix shape of the rotor. These cavities usually are made of synthetic or natural rubber, while the rotors typically are made of hardened steel or stainless steel that is covered by chrome plating to make it more resistant to corrosive and abrasive materials. In wells where the liquid might adversely affect the chrome plating, rotors without the plating are used.

The rotor is connected to the bottom of a sucker-rod string, while the stator is usually at the bottom of the production tubing. As the rotor spins by means of a surface-drive system, it fuses to the rubber stator, forming tightly sealed cavities that move the liquid at a very steady rate toward the surface for production.

This form of lift is ideal for gassy wells because it can tolerate high percentages of free gas, wells with heavy oil and high-viscosity fluids, and wells with high sand production. It contains no valves or reciprocating parts that can clog, lock up or wear down, and its design and materials make it more resistant to abrasion, which also keeps its cost down.

While the pump itself is hardy—with some sensitivity to fluids—the rods and tubing used with it will still wear out in directional and horizontal wells. Its limited lift capability and its limited production rates also are drawbacks. However, due to this pump's versatility and its ability to be used with other equipment downhole, depending on the application needed, it and its components constantly are being improved upon.

Hydraulic pumping systems

As another economical form of artificial lift, hydraulic pumping systems are generally considered reliable for deep wells with solids, sand, paraffin, heavy oil, water, gas and corrosive fluids that might otherwise hamper production. They also are productive in the deviated and horizontal wells used frequently in hydraulic fracturing. This form of lift works best when there is still high-volume production.

There are two forms of downhole hydraulic lift pumps—those that use a reciprocating piston pump and those that use jet hydraulic pumps. In either case, a motor is placed downhole to help force the pressure upward for production.

Reciprocating pumps generally consist of two pistons placed one above the other along a single rod. Once power fluid (oil or water) is shot downhole via a tubing string to power the motor, it forces the hydrocarbons to rise up to the pistons. One of the pistons is driven by the power fluid, and the other is used for pumping the well fluids.

The pressure powers the pistons so the fluids can then be forced to rise to the surface for production.

Jet hydraulic pumping systems will take the pressurized power fluid distributed from the surface through the tubing string and force it through a high-velocity jet nozzle. As the pressurized power fluid is shot through the nozzle, it mixes with the well fluids and forces them up to the surface for production.

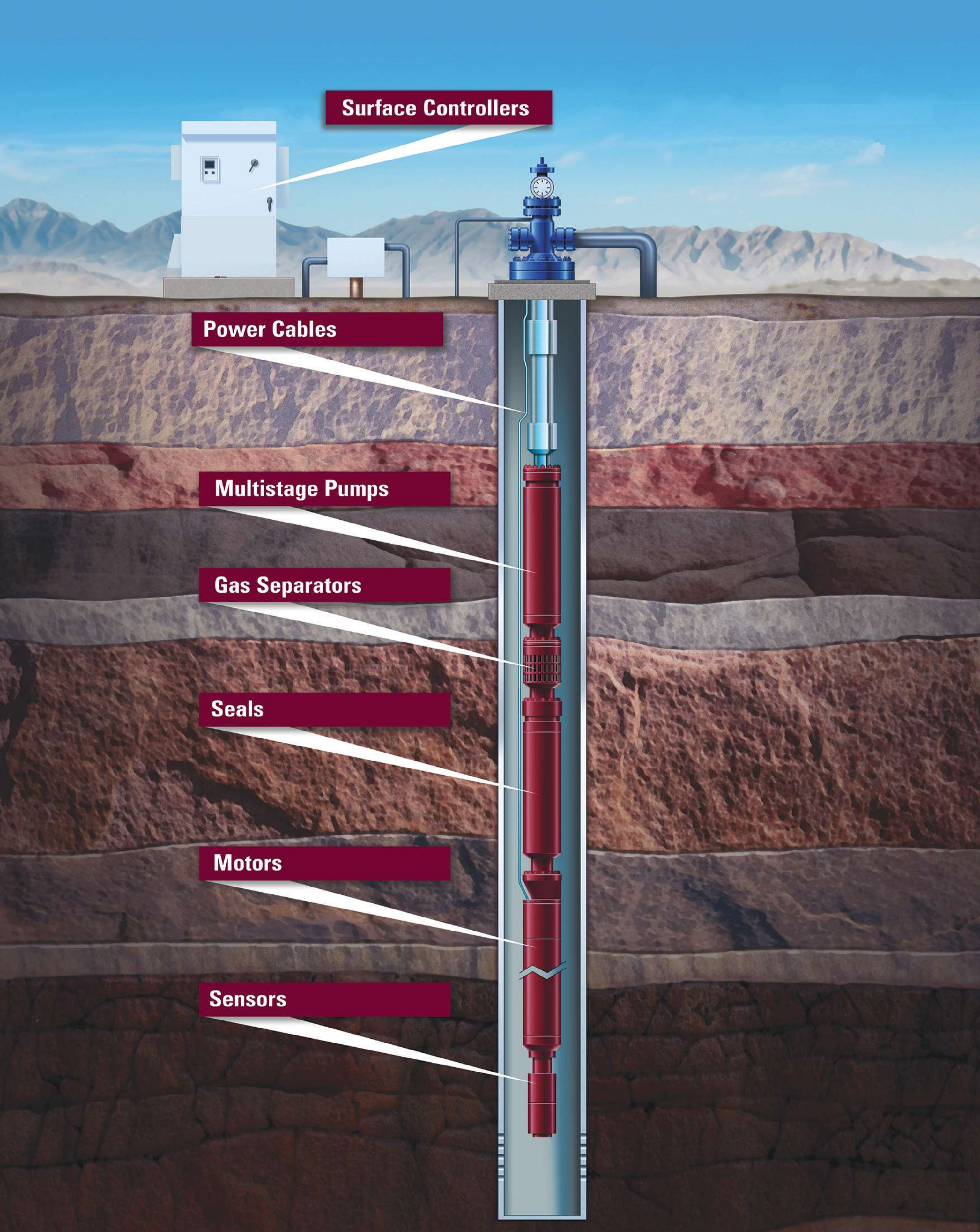
On the surface, a multiplex positive displacement pump that either is powered by electricity or a multicylinder gas or diesel engine will keep the power flowing through the tubing string to the subsurface pump. The surface pump also includes a cleaning system that is used to prepare the power fluids for their trip downhole. This is useful because it allows for the recycling of produced fluids into power.

Disadvantages for hydraulic lift include a shorter lifespan for surface pumps and the need for constant monitoring for best performance. This high-maintenance aspect makes this form of lift less popular in remote locations.

The bottom line

As companies continue to expand into unconventional territories, there will be a call for new and improved technologies in artificial lift. Optimizing production throughout the life cycle of the well is paramount on every operator's agenda, and they can expect to see many more advances from service companies and those specializing in artificial lift techniques in the near future.

However, there is one piece of advice upon which all artificial lift service providers agree: "Take every well on its merits," Bracken said. "Design the system around that well and around the conditions, and put in the best form of artificial lift based on what the well is telling you. That's how you'll achieve the most production." ■


Surface Controllers
Power Cables
Multistage Pumps
Gas Separators
Seals
Motors
Sensors

Tackling the Challenge of Sand Production in Unconventional Wells

Through seal redesign and new product offerings, one company finds success in improving ESP system reliability in unconventional wells.

By Mark Neinast
Summit ESP

Today's completion techniques in unconventional wells require the operator to inject thousands of pounds of sand into the wellbore and into the fractures as proppant to hold the fractures open allowing the oil and gas to flow through these fractures back into the production area of the wellbore. Much of the sand will remain tightly packed in the fractures and will be produced back through the artificial lift system chosen by the operator. The sand that is produced back through the system can have devastating effects on the equipment used to produce this mixture of sand, gas, oil and water.

One common method for producing these unconventional wells is an electric submersible pump (ESP). The ESP is a combination of downhole equipment used to artificially lift the fluid, gas and sand combinations from a producing zone by changing the pressure at that zone and allowing the fluid to be lifted to the surface. An ESP is a centrifugal pump driven by a motor. The motor is powered from the surface using electric cable to transfer AC power to the motor installed near the producing zone. The motor is connected via a shaft to a seal or seals (protector or protectors), which are connected via a shaft to an intake or gas separator/gas handler that is connected via a shaft to the centrifugal pump(s). The centrifugal pump is comprised of stages (impeller and diffuser) designed to lift a certain volume of fluid a certain amount of distance (ft). These systems commonly operate in a range of 2,875 rpm to 4,025 rpm (50 Hz to 70 Hz). At these speeds and high volumes the abrasive sand becomes detrimental to the reliability (life) of many of the components of the ESP system.

Seal protection

One of the components of the ESP system that is affected by the fracture and naturally occurring sand is the seal or protector that is bolted directly above the motor. The seal's general purpose is to protect the motor from well fluid ingress while allowing for oil motor expansion during operation. The seal section provides five main functions, including:

- Provides a fluid barrier between the well fluid and motor oil;
- Allows for motor oil expansion;
- Provides pressure equalization;
- Carries the thrust of the pump bolted directly above the seal; and
- Connects the motor to the intake/gas separator and centrifugal pumps.

Facing page:
An ESP system is a combination of surface and downhole equipment used to artificially lift a well. *(Images courtesy of Summit ESP)*

Fracture sand and formation reservoir sand enter the pump along with the produced fluid. While sand will wear the gas separator and pump, sand generally does not pose a problem to the seal as long as the pump is operating. However, during a shutdown the sand carried in the produced fluids will fall back through the pump and pump intake due to gravity. In the unconventional wells of today, shutdowns are very common as the high volume of gas produced with these wells will slug through these systems intermittently. When the high volume of gas blows through, it unloads the system causing an underload fault on the surface equipment, which triggers a shutdown. The shutdown prevents damage to the system caused by pump cavitation and loss of necessary fluid circulation around the motor for cooling. The fracture sand that falls back through the pump and intake will accumulate at the top of the seal section, which contains a mechanical seal and vent port.

When the pump is put back into operation, accumulated sand will remain at the top of the seal. Over time accumulation of the sand will eventually plug the vent port and prevent well fluid from making good contact with the mechanical seal faces. The mechanical seal faces must be in contact with well fluid to cool the faces. The sand can compact around the mechanical seal and prevent well fluid from transferring heat. The sealing faces will overheat and lead to failure. The vent port is used to vent expanding motor oil to the wellbore to maintain equalized pressure. The expanding oil is released through an internal check valve located inside the seal.

The seal cannot equalize pressure effectively if, as described above, the vent port is blocked off. This will cause a pressure buildup inside the seal to such a degree that it will separate the mechanical seal faces. When this occurs well fluid and sand will enter the clean oil section of the seal.

A bronze bushing in most legacy manufactured seals is located inside the seal section head just below the mechanical seal. Well fluid contamination and sand will rapidly destroy the bronze bushing causing a catastrophic failure due to loss of shaft support. Most seals contain multiple chambers for redundancy. A thrust chamber is located at the bottom-most section of the seal assembly. This protects the thrust bearing from contamination until the last seal chamber is breached. As the seal chambers fail, eventually the shaft will fail due to side loads causing buckling. Seal failures caused by fracture sand fallback have become a very common failure mode of the ESP system in fracked wells.

Seal redesign

Summit ESP took on the challenge of fracture sand fallback by redesigning the legacy seal design, which eliminates concerns from sand contamination, upper mechanical seal failure and shaft bushing overload due to incipient buckling of the shaft. The patent-pending design has added sand exclusion technology just above the mechanical seal. The sand exclusion technology prevents sand from falling into the mechanical seal, eliminating the initial mode for seal failures caused by the introduction of sand. Additionally, a well fluid thrust bearing has been added to the design as well as an improved head design, which allows for increased well fluid lubrication to cool the bearing. The thrust runner is manufactured with tungsten carbide. Relocating the thrust bearing to the top of the seal greatly reduces any concerns of buckling the shaft. The Defender Super Sand Seal includes additional improvements that in effect flush away any accumulated debris from the mechanical seal when the unit is stopped. The bronze shaft bushing has been replaced with a self-aligning carbide bushing that will operate in contaminated well fluid conditions and offers radial shaft support. If the mechanical seal fails, the carbide bushing will continue to provide radial support, thus preventing a failure.

Case history

An operator, operating Mississippian wells in Alfalfa County, Okla., was experiencing short run-life on its ESP systems with standard product technology. The abrasive fracture sands and formation fines were destroying its ESP systems in four to six months, costing the operator $95,000* and $135,000* in opex and deferred production in each failure depending on the type of install. The operator installed Summit ESP systems in two wells: one on Oct. 21, 2012, and the other on Jan. 31, 2013. The company's installations included proprietary AR 1:1 pumps with coated stages and the patent-pending Sand Seal. The system provided robust, continuous operations in the harsh, abrasive environment. The first unit installed is still running today, providing more than 590 days of continuous life-exceeding expectations and more than tripling the expected life of 120 to 180 days. The second unit installed was condemned on May 13, 2014. At the time of this writing the unit has not been pulled and inspected. This unit had 467 days of run time before it was condemned, again exceeding existing life expectancy by more than 2.5 times.

New approach to eliminating fracture sand from the system

The intake on an ESP system bolts on to the seals or protectors, which are directly above the motor. It is connected to the system by a shaft that connects at the bottom end to the seal/protector and the top end via a shaft to the pump or gas separator/gas handlers. The intake is the opening to the wellbore where the fluid gas and solids enter the ESP system.

Summit ESP's patent-pending Fortress Intake offers a different approach to eliminating fracture sand completely from the system. The intake uses a media filter in a modular design as an intake to effectively remove sand particles and trash 20 microns and above in size. The media filter is porous metal manufactured from 316 stainless steel. The application for the Fortress Intake is highly abrasive environments such as fracture sand, formation sand and coarse iron sulfide, wells with known large debris such as packer rubber, wood or other types of drilled-out debris. The intake can be run in conjunction with gas separators, gas handlers or both.

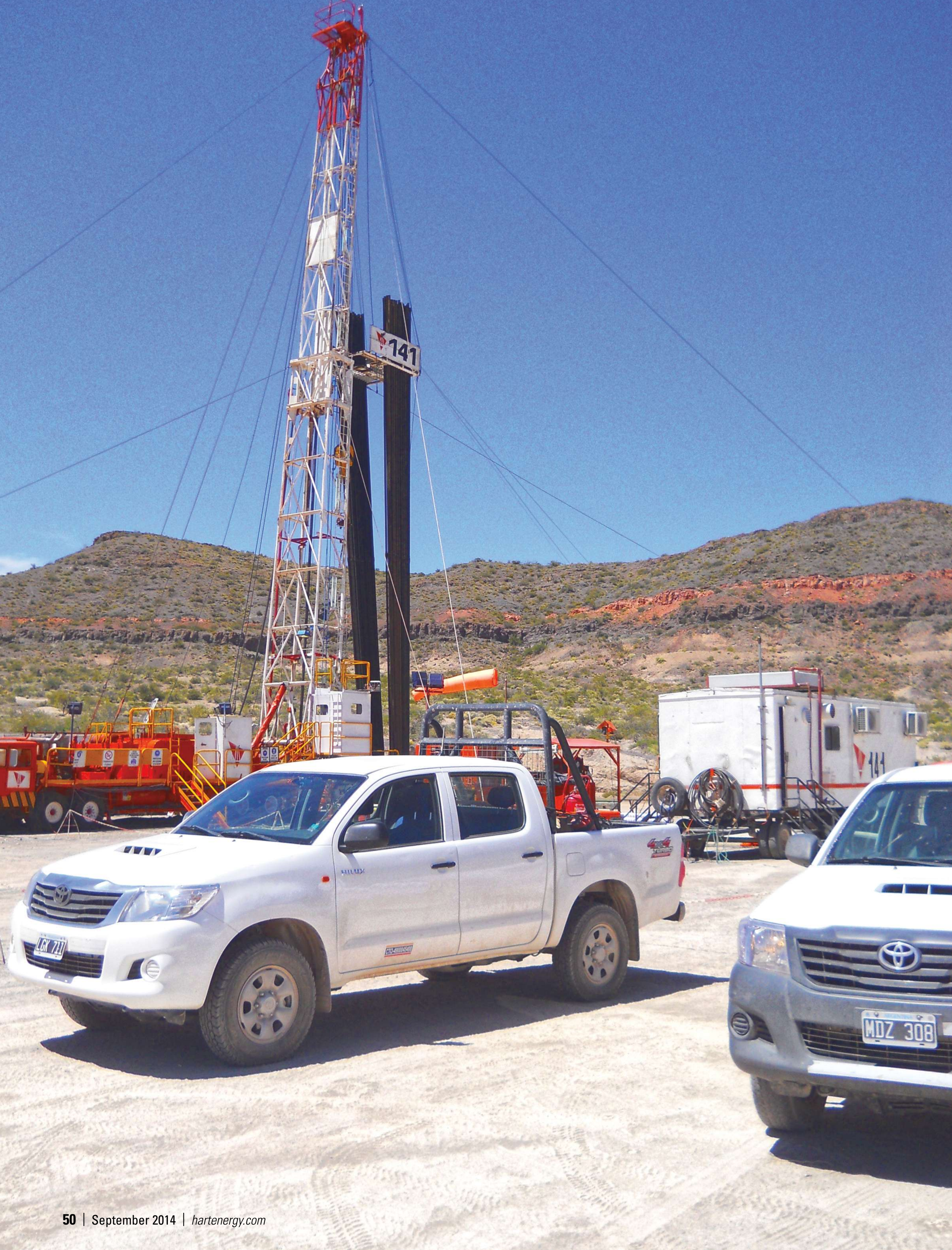
Case history

The prototype Fortress Intake was installed in the same Mississippian formation in Alfalfa County, Okla. It was a six-module, 10-micron, 4,000-bbl/d design. At 52 Hz, production was 2,699 bbl/d of water, 432 bbl/d of oil and 1,063 Mcf/d. The installation was designed to be a well test with a short duration allowing for inspection. The well was pulled 67 days after installation to convert to beam lift. Inspection of the system showed that fracture sand had accumulated on the outside of the media filter. Internal inspection of the gas separator installed directly above the Fortress Intake showed no signs of sand abrasion in the head, the inducer and the gas exit ports. These very promising results are being followed up with several remaining prototype installations before full release of product. ■

This partially assembled Fortress Intake shows some of the components of the design. The intake base is a perforated housing designed for support of the ESP components below the intake and to provide burst strength for the intake. The media (porous) 316 SS filter is installed over the perforated housing in modules.

This partially assembled Fortress Intake shows the intake with the media filters installed, and the final component, a standard intake screen, is being installed in modular sections over the media filter.

*At $85/bbl oil and $4/Mcf gas to calculate deferred production.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Production Boosting in Argentina with New Artificial Lift Solution

A new solution provides an alternative to traditional artificial lift options for use in an emerging unconventional market.

By Fabian Mobio and Santiago Torres
YPF
Ian Schuur and Martin Ezequiel Berardo
Schlumberger

Argentina's burgeoning unconventional market is getting a boost from best practices and technologies proven in the shale plays of North America. The country, which now ranks among the top regions globally for technically recoverable shale oil and gas reserves, has garnered increased industry attention over the past year as production continues to evolve. With opportunities, however, come challenges as operators make that critical shift from conventional to unconventional field development. The transition involves developing in-country expertise and procuring and implementing the protocols, methods, tools and technologies from an established unconventional sector into a new one.

Among the many solutions boosting unconventional production in Argentina is a cost-effective artificial lift system that is enabling operators to develop wells that otherwise would not be viable. In the first extended-reach gas lift project in Argentina, the operator Yacimientos Petroliferos Fiscales (YPF) successfully developed and optimized the system for a well with decreasing pressure and liquid-loading issues.

The permanently-installed system, which was designed after extensive planning with clearly defined specifications and well parameters and implementation of new equipment and training, delivered significant benefits to YPF in recovering a well that had been inactive for months.

Extended-reach gas lift is an artificial lift alternative designed for liquid-loaded gas wells that extends the deepest injection point below the packer and into the perforated zone. In many cases, the high amount of liquids being produced out of the well prohibits the gas from exiting, eventually smothering and then killing the well. The problem is common in unconventional wells, particularly in long horizontal sections, which do not produce sufficient gas to lift the liquids. The high gas-liquid ratio requires an artificial lift method at the bottom of the reservoir.

Other applications where extended-reach gas lift is beneficial include gas-lifted oil wells, oil and gas wells with low bottomhole pressure, wells with long perforated intervals, gas wells with a very low productivity index, wells with small or poor casing and below high-dogleg deviations.

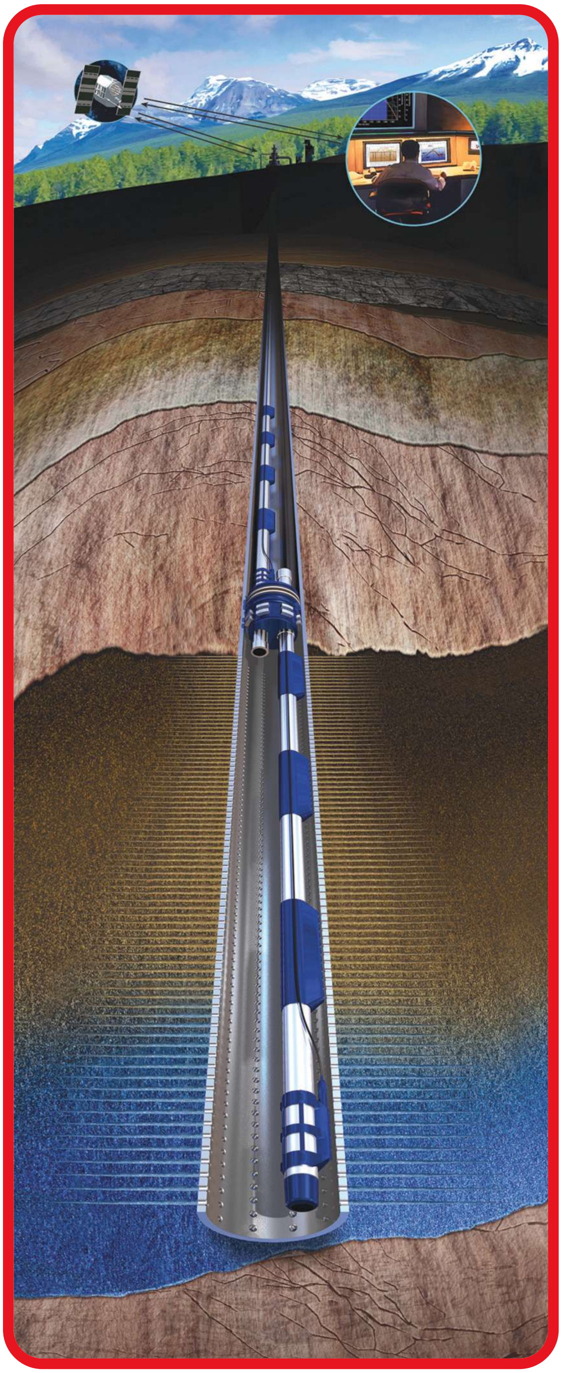
A new artificial lift strategy

The YPF well is being developed in the El Portón Field, an important formation in the prolific

Facing page:
The El Portón Field is home to Argentina's first extended-reach gas lift project. *(Images courtesy of Schlumberger)*

Neuquén Basin, located in the central part of the country. The 6,562-ft vertical well began experiencing production problems early on, when water and condensates began loading up below the packer in a short, 328-ft perforated vertical section, causing large swings in both liquids and gas production.

YPF attempted to resolve the problem with conventional artificial lift methods, used previously in the region that began exhibiting pump-off, resulting in continued well shutdown. Over 15 months, condensates were producing at rates ranging from 35 cf/d to 247 cf/d, while water was producing at rates from 706 cf/d to 1,766 cf/d. Gas rates ranged from 14,126 cf/d to 60,035 cf/d. Due to the intermittence in well production and its decreasing production rates, the well was shut down until a reservoir study was performed. After an evaluation of the well conditions, in September 2013 the company made the strategic decision to deploy the PerfLift perforated-zone gas-lift system.



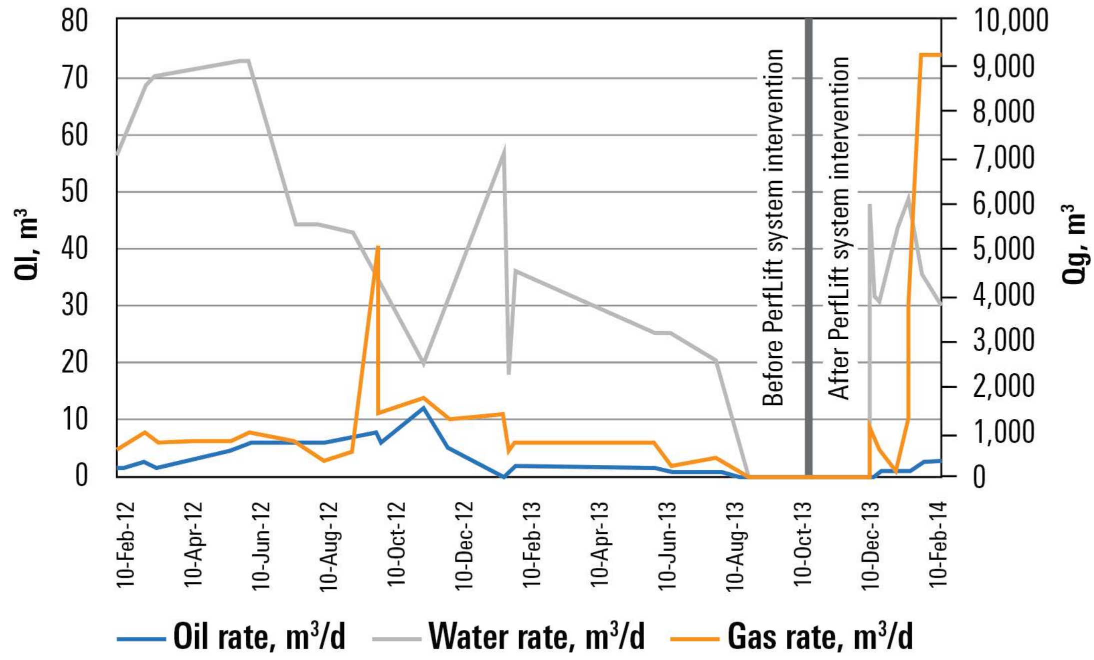
The Schlumberger PerfLift perforated-zone gas-lift system is the only gas-lift system with the proven capability to lift below the packer to the perforated depth of the well.

Introduced in 2005 as a cost-effective artificial lift system for low-rate gas-lifted oil and liquid-loaded gas wells, the system has been used successfully in more than 700 unconventional wells in North America, in some cases more than doubling the amount of gas produced. Designed to improve production in active wells and reactivate dead wells that can no longer be produced with conventional gas-lift methods, the technology allows delivery of chemical and fluid treatments to enhance gas lifting across the entire perforated interval below the production packer. In this way, the system reduces lift costs by optimizing the amount of injected gas and also reduces downtime.

Whereas conventional methods of liquid removal require expensive intervention procedures using a traditional workover rig or coiled-tubing unit, the PerfLift system is permanently installed when the completion is run, eliminating the need for a service rig to install a system after the well is producing. In cases where liquid-loading is an ongoing problem, it can be used continuously to maximize production.

The system uses a series of Camco gas-lift products in tubing strings above and below a ported or dual-bore production packer. Conventional or side-pocket gas-lift mandrels are installed in the upper tubing string. Internal-mount gas-lift mandrels and valves are sized and installed on the lower tubing string across the perforated zone. During the operation, gas is injected down the upper tubing-string annulus and into the lower tubing string through the packer to lift the fluid column across the perforated zone. The liquids are then carried to the surface through the production string.

Production Increases Using the PerfLift System



Production logs show the steady rate of increase in gas production delivered by the Schlumberger PerfLift perforated-zone gas-lift system, which is nine times the historic gas production rate of the well.

Extensive planning was undertaken to deliver a total solution that began with the design of the system, including preparation and documentation of all HSEQ considerations, project readiness assessments and area management reviews. Planning and preparation were undertaken with considerable scrutiny, detail and backup to ensure a flawless execution.

Extensive planning, preparation

A detailed schedule, including all the tasks to be completed prior to installation, ensured the system was deployed on time to meet YPF's deadline. Equipment assembly, preinstallation system integration testing and prejob risk analysis including job documentation, rig visits and prejob meetings with YPF were conducted. Because the project represented a product introduction into a new international market, a 30-day project readiness assessment was carried out prior to the installation. Local crews also were trained to carry out the operation. Some of the tasks were performed in parallel, with all of them completed by Dec. 8, 2013, in preparation for the Dec. 19 deployment.

The well was completed with no problems. The unloading process was launched per the well design, with the artificial lift system injecting gas into the perforated well section, located between 6,165 ft and 6,312 ft. The deepest injection point was installed at 6,270 ft, providing more than 99% vertical well lift coverage.

By augmenting the reservoir gas with injected gas, the system was able to provide the necessary velocity to lift the produced well liquids. After the liquid was unloaded, the well came in and showed marked improvement, with increased amounts of gas produced and liquids and condensates stabilized.

Over a two-month period, as the injection gas cleared the perforated zone, the rate of liquids produced leveled out to a constant rate of 1,412 cf. Gas production, meanwhile, increased to a steady rate of just above 317,832 cf—nine times the historic gas production rate of the well.

The well is continuing to produce without interruptions, with the operational parameters adjusted accordingly and injecting within the perforated zone, thus paving the way for future deployments of the PerfLift system in more than 2,000 wells that have been identified as potential candidates. The success of the project has provided Argentina with a new artificial lift alternative that has the potential to make a significant contribution to growing shale gas and oil production in this important, emerging unconventional market. ■

Expected Life from Sucker-rod Lifting in Horizontal, Highly Deviated Wells

Injection-molded rod guides have shown long life.

By Norman W. Hein Jr.
Norris/AOT and Dover Artificial Lift

Some believe horizontal wells were first drilled in the U.S. in 1927, while others have referenced that the first true horizontal well was drilled in Morgan County, Ohio, in 1939. When the reservoir pressure for these wells started to deplete and the production rates started to decrease, the owner/operator probably considered installing some form of artificial lift to see if the production rates could be enhanced. This is not any different than any other type of producing oil or gas well—whether vertical, horizontal or highly deviated—except back in the '20s and '30s there were not as many lift techniques to consider. Thus, these wells most likely had the reciprocating sucker-rod lift method installed.

As current technology for producing unconventional reservoirs continues to challenge all the forms of artificial lift, one always should consider the method that has the longest history and the most operator knowledge and experience as the first choice if the producing rate is within the lift and depth capacity of sucker-rod lift. However, many are concerned with the downhole wear that could occur when the sucker-rod string is installed in the production tubing.

The expected run life for sucker-rod-lifted horizontal and highly deviated wells when proper problem-solving techniques are applied to these wells is discussed in this section.

Background

There have been a number of recent papers about sucker-rod lifting in horizontal and highly deviated oil and gas wells. These have discussed the published history of rod pumping these types of wells, design practices, wellbore geometries, undulations or traps along the horizontal section, placement of the pump and effect on the run time or failure frequency along with effect on production.

One of the concerns with using the sucker-rod lift method is the potential for the sucker rods or sinker bars that make up the rodstring or the couplings used to connect the rods for conventional sucker-rod lift to contact the inside of the tubing and wear a hole. Additionally, there is the added concern that if the rods and/or coupling wear, then it will have a reduced load-carrying capacity and will cause an early failure of the rodstring.

Some operators have thought not using couplings to connect the screwed-together rodstring will avoid the potential of coupling wear or connection failures. They have considered that if a welded, spoolable sucker-rodstring was used then they would have less failures and adequate run time. Other operators have considered using spray metal-coated couplings with properly made-up connections and properly operating the wells so the connection does not loosen downhole. They have seen extended operational life of the well and have not been concerned with the problems of needing special equipment to install or remove continuous sucker-rod strings. There is a growing group of operators that consider avoiding any contact with the rods, sinker bars and couplings by using sucker-rod guides.

One of the concerns with using the sucker-rod lift method is the potential for the sucker rods or sinker bars that make up the rodstring or the couplings used to connect the rods for conventional sucker-rod lift to contact the inside of the tubing and wear a hole.

Sucker-rod guides

Guided rods have been available to the industry for more than 25 years. Over time, the uses and misuses as well as various application methods, designs or shapes, and available plastics have evolved to provide a product that can adequately protect the downhole rodstring and production tubing allowing for extended operational run time.

A recent paper has been published by an operator of "S-shaped" wells that have been drilled from pads in the San Juan Basin Fruitland coalbed methane field. While these wells might be considered shallow with depths of about 4,200 ft, sucker-rod lift has been installed to allow deliquification and to maximize gas production by drawing the wells down the greatest amount. The paper discussed that the wells have been drilled as S-shaped with the two curved sections and associated side loads greater than 100 lb. This typically resulted in dogleg severities of 1 degree to 6 degrees per 100 ft.

Run time results from rod guide use

Figure 1 shows an example well and the side load with depth. Also shown is a comparison of a wellhead tubing scan run after a failure occurred from a hole in the tubing. The side loads were estimated using a sucker-rodstring design software program that considered the wellbore deviation survey and the associated load that could be provided from the rodstring and fluid load at depth. It is interesting to note that while the dogleg severity for these wells was less than 6 degrees, the resulting side load is much more of a concern on the operational run time. Also, the side loads at the surface due to the deviations at the surface when compounded by the highest loads from the rodstring resulted in the highest side load. Even though this well in the figure was shallow (about 3,800 ft) the side loads approached 400 lb at the surface, while the greatest side loads

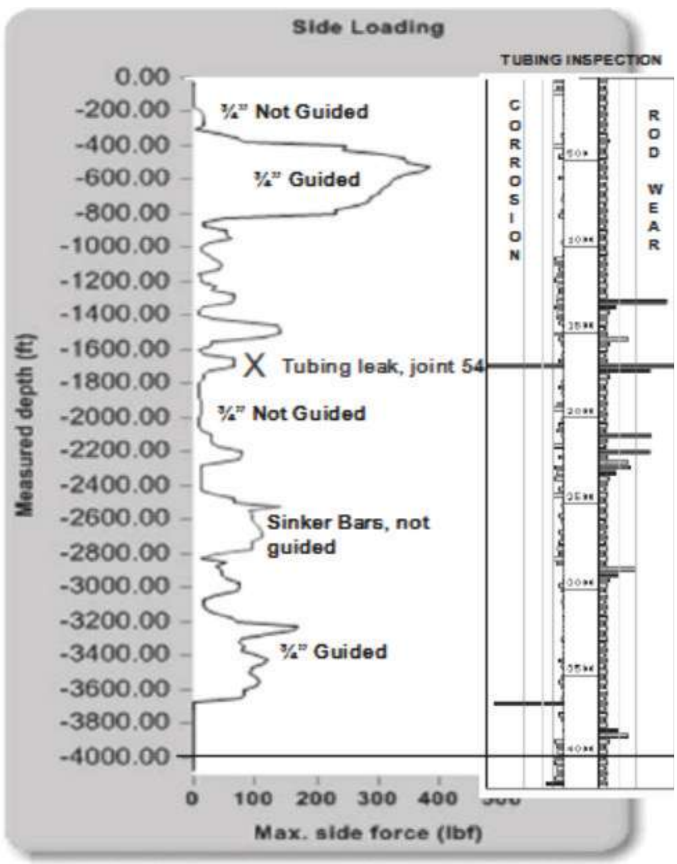


Figure 1
Side load estimates with depth vs. wellhead tubing inspection results comparing potential corrosion pitting and/or rodstring on tubing wear are shown. *(Images courtesy of Dover Artificial Lift)*

downhole were 100 lb to 200 lb.

There were two areas where the sucker-rodstring was guided with injection-molded rod guides. The first was at the surface over the interval from about 300 ft to 800 ft. The second area of guides was from about 3,300 ft to 3,700 ft. However, a hole in the tubing developed at a depth of about 1,700 ft. The hole in the tubing was designated in this graph with an "X."

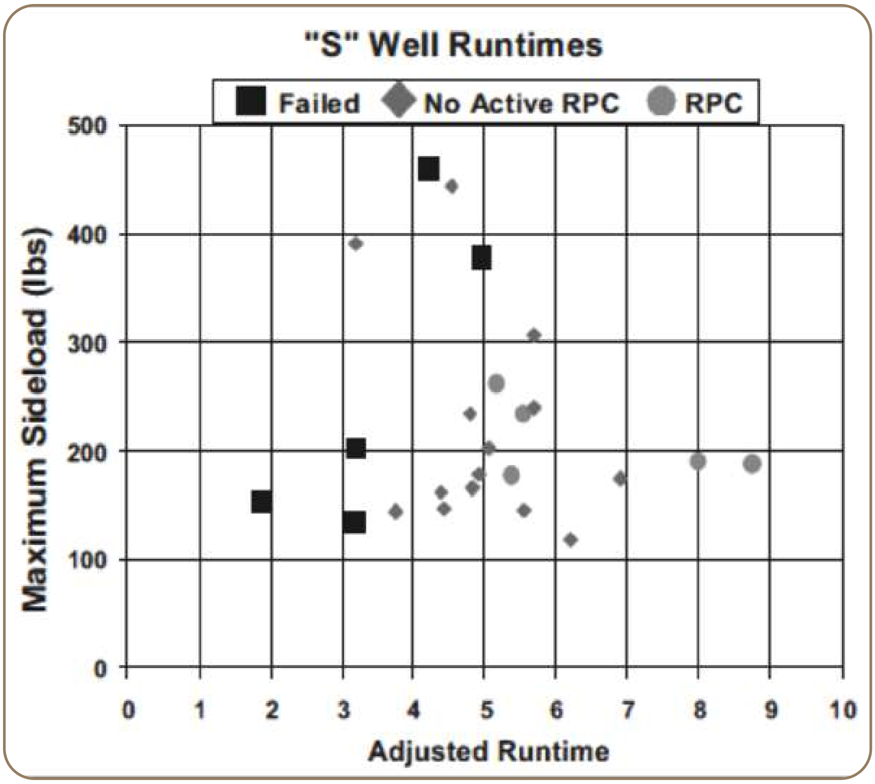


Figure 2
A failure monograph of run time (years) vs. side load is shown.

This depth also correlated very well with the output scan from the tubing inspection. It is interesting to note that the operator did not run molded-on sucker-rod guides in this constant build interval where the hole developed since the side load estimate was about 60 lbf. However, without guides, the rodstring constantly was in contact with the tubing, and a deviation at the depth caused the hole in less than one year.

Figure 2 shows a summary of the run time for a number of various wells in this study. Some wells had a rod pump control (RPC) to automatically control the operating time for the well, and some wells did not. Any failure was designated with a black square at the approximate side load and the approximate run time (in years). While there were three wells that had failures in two to three years with side loads of about 100 lb to 200 lb, most wells with side loads from 100 lb to even 300 lb have lasted more than five years with some lasting for more than eight or nine years without any failures. Finally, it should be noted that some wells have operated for four to more than five years with about 400 lb to 450 lb of side load. This is considered very high side load; however, that is based on the normal side loads from conventional, vertical type wells.

Summary

The results from this operator have shown that—with proper makeup and operation practices, along with the use of injection-molded rod guides where side loads exceeded 50 lb—very good run times of more than nine years might be obtainable even with side loads of about 200 lb. Results also have shown that while dogleg severity has been a concern in the past for vertical wells, side load effects are more important. Adequate operating life of four to five years might be obtained even with high side loads of 400 lb to 450 lb, but about eight to 10 properly designed injection-molded rod guides with appropriate plastic material were required on the rodstring with the high side load depth interval. Finally, rod-on-tubing wear in a constant-build section where no guides were installed might have a short run time and might impact the consideration of using any rodstring that is not adequately protected with guides to prevent wearing itself or wearing a hole in the tubing. ■

Editor's note: For additional information on sucker-rod lifting, see the References section.

Companies Collaborate for Unconventional Solutions

Innovation comes from within companies, from consortia and even from outside the oil and gas industry.

By Bethany Farnsworth
Associate Managing Editor, *E&P*

Progress in unconventionals means new frontiers, business growth and the excitement of untapped resources underfoot. Unfortunately, it also can mean technology is outdated, production slows rapidly and new challenges are confronted constantly when trying to use artificial lift systems.

Because of the low permeabilities of unconventional reservoirs—sometimes less than 1 microdarcy—the fracturing of these wells provides an initial high volume of production that drops off rapidly as the fractures drain, said William Lane, vice president of emerging technology for Weatherford artificial lift systems. The inflow into the fractures becomes a slow seepage commonly resulting in decline rates of 60% to 80% in the first year of a well's production. "Artificial lift is required sooner in unconventional wells than for conventional wells, and the lift systems must have wide operating envelopes to handle the wide variation in production volumes," Lane said.

The long lateral sections also pose a problem. Although called horizontal, these laterals are rarely straight or totally horizontal. It's not uncommon for undulations in the horizontal section to be more than 25 ft in height, Lane said. In gas wells with low bottomhole pressure, the undulations can create liquid traps that add backpressure and cause slug flow.

As companies dive into unconventional resources, they are all facing similar problems with artificial lift technologies. While the specific focuses of R&D projects around the industry vary, a look at a few companies' R&D efforts reveals some common research areas: handling particulate matter and gas separation, automation, high-temperature challenges and applying the newest technology to artificial lift. Collaboration is taking place among groups within companies, between companies and even with engineers from industries outside of oil and gas.

Industry centers

Some companies are taking on the new challenges of unconventionals with dedicated artificial lift research centers. Baker Hughes' new Artificial Lift Research and Technology Center opened in February in Claremore, Okla. The $60 million center was designed by employees for the research, engineering, design and testing of artificial lift technologies.

"We realized … we were going to have to change some of the testing capabilities," said Wade Welborn, vice president for artificial lift, at the facility's grand opening event in February. "What does it look like 10 years from now? What do you need 20 years from now? How do you lead in this facility over the years?"

The center is adjacent to the company's artificial lift product center. It houses six vertical test wells of various diameters and depths for testing a range of technology from electric submersible pump (ESP) system components to full production systems of artificial lift and completion equip-

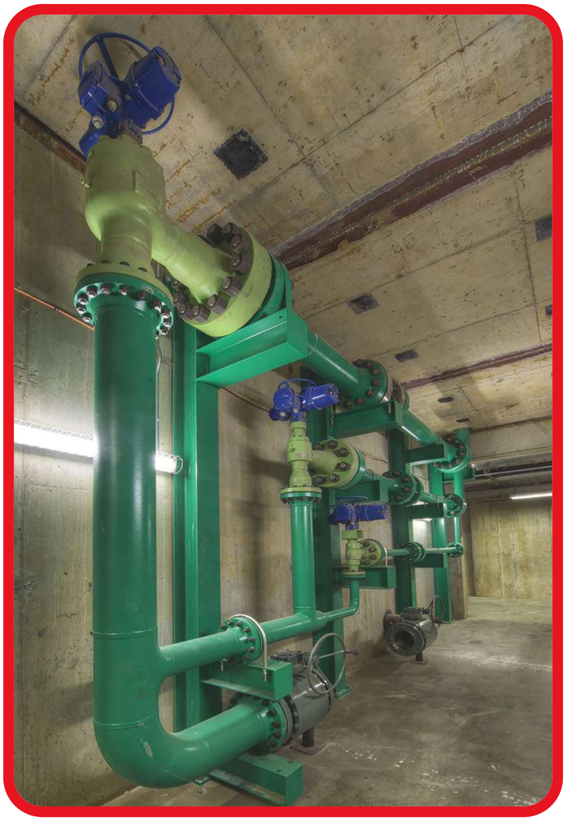
Baker Hughes opened its Artificial Lift Research and Technology Center in February in Claremore, Okla. *(Images courtesy Baker Hughes)*

ment. A seventh well tests system horsepower for specific purposes.

The location of the center allows engineers from R&D, manufacturing and the quality and reliability teams to work together to develop technology to increase ESP system reliability in harsh environments with high intervention costs, expedite new product development and commercialization, carry out total system integration testing prior to installing a system in a field, test alternative intervention methods and meet material traceability requirements.

The center has its own motor winding area, welding shop and machine shop so new technology or system assembly, testing and teardown can be done independent of the manufacturing facility.

"We can take the designs that we build up on the second floor immediately into prototypes and directly into the wells under the floor," Welborn said. "That will greatly improve the time from concept to commercialization of our products."



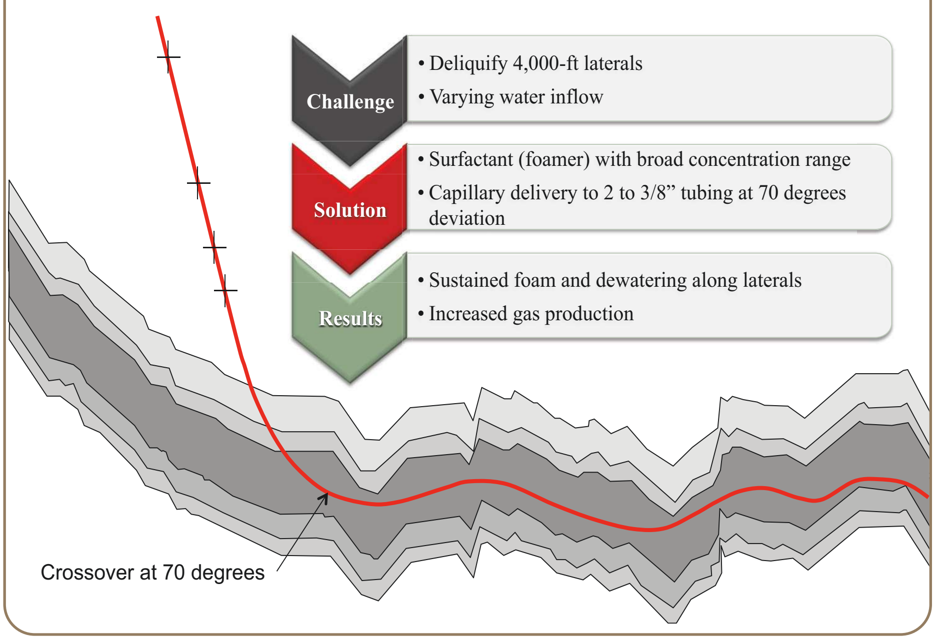
Each test well in Baker Hughes' Artificial Lift Research and Technology Center has a dedicated flow manifold with three valves, which allows testing systems at various flow ranges.

Representative US Shale Play Metrics

Metric	Barnett	Eagle Ford	Woodford	Haynesville	Marcellus	Bakken
Thickness (ft)	100 to 600	23 to 183	70 to 290	200 to 350	45 to 225	10 to 40
Typical TVD (ft)	6,000 to 8,500	6,000 to 13,000	10,000 to 16,000	10,000 to 13,500	4,000 to 8,000	7,450 to 11,100
Typical MD (ft)	11,500	16,800	14,400	16,500	11,500	20,000
Typical Lateral (ft)	3,500 to 5,000	3,500 to 5,000	4,000 to 5,000	4,000 to 7,600	4,00 to 5,500	4,000 to 10,000
Permeability	**<5µd**	**1µd**	**<1µd**	**<1µd**	**20µd**	**40µd**
IP Rate (MMcf/d)	2.5	19.3	5.1	14.3	3.5	791 boe/d
EUR/Well (Bcfe)	2.8	5.9	4	6.5	4.5	400-700 Mbbl
Avg Decline Year 1	65%	75%	59%	81%	64%	80%
Avg Decline Year 2	34%		43%	41%	35%	
Avg Decline Year 3	19%		32%	26%	21%	
Decline Out Years	6%	6%	5%	5%	5%	
Water Usage[1]	4 MMgal	5 MMgal	4.5 MMgal	6 MMgal	5 MMgal	4 MMgal
Water Flowback[1]	← 5% to 30% →				1 MMgal	

[1]Per total frack job, *Techno-economic Assessment of Water Management Solutions*, Gas Technology Institute. July 2011

Dewatering Laterals with Capillary Foam



Weatherford's past artificial lift R&D efforts have included deliquefying long laterals using surfactant foam technologies. *(Images courtesy of Weatherford)*

GE Oil & Gas has broken ground on the new Oil & Gas Technology Center in Oklahoma City and signed a technology collaboration agreement with Devon Energy Corp. The agreement will see the companies partner on projects at the new center, which is due to open in third-quarter 2015 and will focus on advances in technologies for three specific areas of unconventional drilling; one of these is innovation in artificial lift systems.

Global research

Weatherford does R&D work globally with much of it taking place in Houston and Edmonton. The company has made great strides in artificial lift in the past, such as deliquefying 4,000-ft laterals in shale plays using surfactant foam technologies, and it continues to push toward new answers.

One area of concern is tolerance to sand and particulate matter, Lane said. Unconsolidated or loose material coming back from the well is common in all types of wells. Additionally, the fracturing process leaves a lot of loose proppant that flows back during fracturing fluid recovery. Particulate matter can be very destructive to run through pumps over a period of time, so the company is focusing attention on pumping systems that can tolerate sand and particulate, resulting in longer lifespans for the pumps.

Many projects at Weatherford work toward advancing the capability to manage production using digital technologies. "There is an ongoing effort to advance our production optimization systems, which include advance sensors, software and integration of various software elements," Lane said.

Other research areas include improved efficiency and runlife, horizontal artificial lift and hybrid systems to facilitate migrating from one lift technology to another in applications with rapidly changing production rates.

ESP advances

The Artificial Lift Technology organization within Halliburton focuses on the company's ESP product line. Its R&D is concentrated on three main areas.

The first is gas separation and particulate handling. "These pumps are being put into applications that they were never really intended for," said Mark Woodmansee, technology director of artificial lift at Halliburton. "Very often, they're put into wells that have a lot of frack sand, particulate, gas, solids [and] even old pieces of material from previous drilling campaigns. And they're being expected to perform for a long period of time despite not just pumping liquid but all these other media."

In horizontal wells, the best use for ESPs still is being explored. ESPs have traditionally been positioned in the vertical portion of the well, but recently operators have started putting ESPs in a deviated section or even laying them down in the horizontal, Woodmansee said. Doing that, though, introduces new problems. Operators might face slug flow where they are essentially dealing with slugs of fluid separated by pockets of gas that impact the entrance of the ESP when it's laid down in the horizontal section.

"We're developing some test equipment to allow us to test ESPs in different orientations [angles]," Woodmansee said. "We'll be able to introduce what we think will be the two-phase mixture that's going into the ESP to understand if there's a better way that we can separate out these liquid, gas and solid phases to prevent erosion from particulate or to inhibit gas lock in the pump when a slug of gas comes through."

The second area that Woodmansee's group is addressing is the end of easy oil. Production is coming from increasingly difficult-to-access reservoirs, many with temperatures from 347 F up to 482 F for heavy oil and tar sands. The group is looking at incorporating high-temperature motors into some of the company's base-level products.

The last area of focus is automation and optimization. With rapid changes in the way and the time it takes for the fluid to come to surface, it's important for operators to be able to monitor and then optimize the way their artificially lifted wells are performing.

Halliburton's Artificial Lift Technology group has eight projects underway that are split among its three core focus areas. One project, for example, is looking at pump stages. An operator will typically run an ESP for six months or so until the well declines to the point that another lift technology is needed. "We're looking at some new types of pump stages—basically the impellers and diffusers that make up the centrifugal pump in an ESP to allow the ESP to remain in the well through the majority of its viable production period," Woodmansee said.

Collaborative R&D

At Schlumberger, most of the team members in the company's artificial lift organization are involved in some way or another with the R&D process, from designers and engineers who focus on continuous improvements and new product development to field operations employees who help originate technology development, said Angus Melbourne, president of artificial lift at Schlumberger. This collaboration has resulted in technologies such as the company's REDA HotlineSA3 high-temperature ESP system and the Endurant ground-fault-immune ESP monitoring system.

Much of the company's research focuses on optimizing ESP use and improving monitoring operations for longer life cycles and increased production.

The Endurant ground-fault-immune ESP monitoring system provides continuous monitoring of key system parameters in high-temperature wells up to 302 F. *(Image courtesy of Schlumberger)*

One area of research looks to maximize ESP uptime while improving reservoir understanding. "The goal here is to design an ESP monitoring system that will not only outlive the ESP but also closely monitor and record the changes in reservoir conditions," Melbourne said. The company also is working on rigless ESP deployment, which would enhance the life-cycle management of artificial lift systems and their effectiveness.

Schlumberger is addressing the challenges of "prognostic health monitoring," which is achieved through automation and predictive maintenance. For this to happen, companies must have forward-looking, proactive, automated workflows that prolong a product's life cycle while still ensuring maximum production and efficiency, Melbourne said. Schlumberger is exploring the idea of a fully automated submersible lifting technology, which it believes could have significant potential for the industry.

Improvements in real-time monitoring operations are also on the company's R&D list. "The benefits are obvious," Melbourne said. "When you can react in real time to data and alerts, you can prolong equipment life and increase uptime, improve lift system performance, reduce operating costs and gain immediate increases in production."

While many of the challenges in horizontal wells—reliability and efficiency for example—are relevant to all artificially lifted wells, Schlumberger is researching the unique behavior of fluid flow in unconventional horizontal wells. "Fluid behavior is an ongoing challenge because of the issues of gravity, viscosity, multiple zones and multiphase flow," Melbourne said. "One research goal is improving the accuracy of reservoir modeling and simulation in these wells."

Learning from other industries

While the industry is pushing past barriers it hasn't encountered until now, there are many similarities between the challenges facing oil and gas and those that other industries are confronting or already have solved. Artificial lift R&D groups aren't ignoring the opportunities to leverage the knowledge in other industries.

"What you think is maybe really hard to do in the [artificial lift] industry, it turns out that other people have already cracked that nut," Woodmansee said. "They just haven't applied the new technology to this particular market."

Aircraft engines, for example, already have dealt with high temperatures. "We in the ESP industry are struggling to get to 250 C [482 F], and in the aircraft engine industry, their life starts at 650 C [1,202 F]," he said. "Know it or not, they probably have answers that could be used to solve a problem in our industry."

Weatherford has employees whose job is basically to look for new innovations as they come out, regardless of where they've been applied. Key technology experts interface with those in other industries to understand the latest advancements in technologies that might have applications in oil and gas products. "Our elastomer chemists will interface with chemists from other industries—for instance, the tire industry and other areas—so we understand what the latest technologies are worldwide, not just in the oil and gas industry," Lane said. "That's just one example."

Woodmansee's hiring philosophy is based on this idea of bringing fresh thinking to the R&D table. He's been building a team of engineers for his ESP-focused organization, but many of Woodmansee's engineers—including Woodmansee himself—don't have ESP backgrounds. The group is located in Houston, away from the typical world of ESP development in Oklahoma, and takes advantage of a different set of engineering knowledge.

"They may not have ESP experience *per se*, but they understand some of the latest innovations in technology whether it's advanced computational modeling or new coatings that are being introduced into other markets or even new manufacturing processes," Woodmansee said.

It's this outside experience and new thinking that Woodmansee believes is going to bring the greatest innovation to the artificial lift market and ESPs in particular.

Leveraging others' knowledge

While companies are looking to other industries for applicable innovations, many also are collaborating with each other to take advantage of the knowledge available in the oil and gas industry through organizations like the Artificial Lift R&D Council (ALRDC). This group was officially formed in 2005 with support from Weatherford and Texas Tech University.

"We wanted a private, nonprofit organization that could support artificial lift for the worldwide community in several ways: education, seminars, a technical library, recommended practices and artificial lift R&D, including many other ways," said Cleon Dunham, president, CEO and secretary of the board for the ALRDC. "Being a nonprofit serves very well to allow companies to come together without fear of restraint of trade issues."

The ALRDC's goal is to share information among those with an interest in artificial lift around the world and to promote appropriate R&D for improved practice.

Members of the ALRDC can access case studies, recommended practices, a technical library and more on the organization's website as well as attend workshops and seminars the group organizes.

The organization's role in R&D is to help identify needs for projects; find organizations that can provide resources or funding to a project; and help organize project objectives, plans, schedules and more. R&D projects can be open or proprietary. Open projects are available for potential participation by any R&D provider or customer. Proprietary projects are restricted to the specific organizations that are involved in the project, and the access to the information on the project is restricted to these organizations. Specific research areas include sucker-rod pumping, plunger lift and well modeling, among others.

TUHWALP

One research project that the ALRDC helped create is the Tulsa University Horizontal Well Artificial Lift Projects (TUHWALP) to focus on the effective production of horizontal wells. The company invited a number of companies to address these challenges, and they decided to address the problems in a consortium format with the University of Tulsa as the host institution. The TUHWALP started its activities on July 1, 2012.

"There are companies that have extensive flow loops to do all the testing in horizontals themselves, but I tend to think that a consortium is a way to leverage your resources and get a broader set of answers," said Lane, who is chairman of the ALRDC's R&D committee in addition to his role at Weatherford.

The TUHWALP's current projects are an investigation of multiphase flow behavior in horizontal wells, an investigation of artificial techniques in horizontal wells and the development of guidelines and recommended practices.

Member companies include the ALRDC, BP, Chesapeake Energy, Chevron, ConocoPhillips, Devon, Encana, ExxonMobil, GE Oil & Gas, Lateral Resources, Marathon Oil Corp., Norris Production Solutions, Range Resources, Shell, Southwestern Energy and Weatherford.

TUALP

Though the projects focusing on horizontal wells are new, the University of Tulsa has been researching artificial lift since 1983 when the Tulsa University Artificial Lift Projects (TUALP) research project was founded. Current projects include:

- Experiments and computational fluid dynamics (CFD) simulation of ESP sand erosion;
- Oil/water flow and emulsion formation in ESPs;
- CFD simulation, experiments and modeling of ESP performance conditions;
- Experimental study of water, oil and gas three-phase ESP performances;
- Artificial lift conditioning for deviated and horizontal wells;
- Transient gas-lift modeling;
- Mechanistic modeling of ESP performance for single-phase and gas-liquid flows;
- Transient modeling of plunger lift for liquid unloading from gas wells and oil production from high gas-oil ratio wells; and
- Modeling of artificial lift integration in production systems.

Member institutions are Baker Hughes, Chevron, GE Oil & Gas, Pemex, Petrobras, PetroChina, Petroleum Experts, Schlumberger, Shell International and Statoil. ■

Additional Information on Artificial Lift

For more details on artificial lift, consult the selected sources below.

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