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## Artificial Lift
The 2018 Techbook

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On the cover: Beam pumps at work producing oil from southeastern New Mexico’s Delaware Basin. (Photo by Jennifer Presley, Hart Energy)
As the oil and gas industry continues recovering from the most recent bust cycle, the artificial lift segment is finally beginning to climb out of its slump. Because artificial lift equipment typically is not purchased until a well is completed—or much later—the sector’s recovery has lagged behind other oilfield services.

According to Dimitar Kostadinov, a senior analyst with McKinsey Energy Insights, the artificial lift market has been improving with the recent rise in well completions. The firm expects the artificial lift sector to be strong in 2018 and to turn in even stronger results in 2019 due to completions of new wells. Kostadinov does not, however, believe pricing will recover to pre-2015 levels.

One reason is because beam pumping units and gas-lift technologies have been largely commoditized but also because international players have aggressively entered the local market to put pressure on prices, according to McKinsey.

Operators changed the way they bought artificial lift equipment during the downturn. In the past they preordered units and even paid extra for access to manufacturing capacity for beam pumping units and electric submersible pumps (ESPs), according to Kostadinov. Now the operators are tending to contract for the units much closer to the expected installation date. The shift minimizes inventory and improves cash flow. The company said if such an approach continues, artificial lift procurement will be more of a spot market than a bulk market.

“It’s been an interesting journey since the downturn and the commodity price change,” said Paul Mahoney, president of Apergy Production and Automation Technology. “It seems there’s a trend back to financial discipline and operating within cash flow.”

Stability in oil pricing is having another effect, he said.

“A lot of the operators are getting back to taking care of their wells. There’s more maintenance and repairs. Well servicing activity is starting to pick up slightly and is projected to pick up some more here in the balance of this year,” Mahoney said.

When it comes to artificial lift in unconventional plays, he noted there seems to be a move toward providing lift earlier in a well’s life.

“It’s driving more activity on the gas-lift, electric submersible pumps and, in some cases, the hydraulic lift area. We’re seeing more activity and good growth rates in those areas,” Mahoney said. “You have some of the shorter laterals from earlier unconventionals work in 2013 and 2014 starting to mature, and the production rates have declined to a point where some decisions on a change of technology is afoot, converting to the tried and true reciprocating rod lift arena.”

According to Kostadinov, the last few years have shown some changes in the preferred technology used in artificial lift, with operators installing more gas lift at the expense of ESPs and some higher capacity beam pumping units. The cost of installing gas lift is lower than other technologies, associated gas production is abundant and compressors can be rented to spread the cost over time. McKinsey noted some Permian-focused independents have entirely shifted to gas lift for their newly completed wells.

The last year has shown a resurgence in ESP use, boosted by rental offerings, according to the company. Beam pumping units have been pushed back in the
pecking order for new wells in the Permian but remain popular in other basins.

**Drive for innovation**

Operators are favoring automation and remote monitoring systems in an effort to improve efficiency. Operators are clamoring for technologies that can widen the operating envelop for artificial lift, Mahoney said.

“There’s been a renewed emphasis on developing technology that helps the operator with the wider operating range in downhole conditions. That’s getting more and more prominent,” he noted.

Conditions include declining production rates as well as handling large amounts of gas, solids and sand.

The biggest push is around automation and analytics with the goal of monitoring wells, analyzing data to extend equipment life, predicting failure patterns and fieldwide production management, he added.

“We’re trying to marry our installation base, our application knowledge and collaboration with customers to bring digital automation capability to the market that drives outcomes and better decision-making for the operator,” Mahoney said. “We’re working on new product development to extend the ranges and handle adverse downhole conditions.”

Apergy’s efforts target a combination of extending existing technologies and developing completely new industry technologies.

“We have some things in the early ideation stage with preliminary engineering work going on,” Mahoney added. “There’s no silver bullet, but a company like ours is working on four or five major new things to support the industry.”

According to Kostadinov, oilfield services companies have gradually raised the overall quality of their artificial lift offerings, incrementally improving gas handling and lifting liquids from deeper laterals. The overall resistance of pumps and related equipment also has improved. The modularization of artificial lift, especially ESPs, has resulted in less rig time and lower installation costs, with equipment coming in fewer parts and also preloaded with consumables like oil, he added.

One of the existing challenges in artificial lift is access to people and parts, which is crucial for supporting customers. Education also can be helpful, Mahoney said. The company’s Artificial Lift Academy offers more than 50 courses to help train industry personnel on artificial lift technologies, engineering tools and digital technologies.

“Some operators know the guidebook or playbook they want to exercise for artificial lift and … a good percentage of customers don’t know what their playbook is and they’re looking to companies like ours to be able to provide that guidebook for them [and] what makes sense over the life of the well,” Mahoney said.

While the market for artificial lift equipment has been a difficult one in the most recent downturn, Mahoney is optimistic about the sector’s future.

“Artificial lift will always be needed,” Mahoney said.
Maximizing Production with Artificial Lift and Automation

These key players have mastered the art of recovering more production via artificial lift.

By Ariana Hurtado, Associate Managing Editor and Brian Walzel, Associate Editor, Production Technologies

Production optimization is a key driver for maximizing returns on investment, and artificial lift is a go-to optimization solution. As drilling activity continues to increase in the U.S. unconventional resource plays, so too will the need for cost-effective lifting solutions to prolong the productive life of wells in these maturing plays. The selection of the optimal lift methods and strategies for their use over the life of the well are just two of many areas where providers of artificial lift products and services are assisting operators.

The following is a sampling of companies that provide artificial lift services in areas ranging from automation, equipment and telecommunications.

Key Players

**ABB**

ABB offers industrial IT systems for the artificial lift industry, including a range of automation systems to operate, monitor and control oilfield production.

ABB’s Industrial IT Pumping Artificial Lift Solutions (PALS) create a control and information infrastructure that can be designed for one well or hundreds of wells. PALS feature multiple language support, security and access control, intuitive configuration controls and network connectivity.

The company’s Aspect Objects integrate information from a variety of applications and makes it available in real time to any authorized user regardless of their location. With Aspect Objects, artificial lift data and components are presented as configurable software objects. Variable speed drive systems include low-voltage AC drives, medium-voltage AC drives, motors and programmable logic controllers.

ABB’s progressive cavity pump and electric submersible pump control program features backspin control, pressure protection, thermal protection, fluid level control and acceleration ramps that improve production and help protect artificial lift systems. The program is available for low-voltage industrial ACS880 drives in power ranges from 0.75 kW to 5,600 kW. ABB’s industrial and medium-voltage drives work to adapt the motor speed to actual need, which optimizes energy consumption and reduces CO₂ emissions.
AccessESP
AccessESP provides wireline retrievable electric submersible pumps (ESP), permanent magnet motors (PMM), and research and engineering.

The company's technologies, a PMM and a side pocket wet-connect system, form the Access375 system that works in 4.5-in. tubing and is designed to allow slickline retrieval without killing the well and fullbore access when pulled. The company's ESP completion system is designed to “significantly reduce the impact of deferred production and rig costs on high-end ESP wells,” according to the company's website.

In 2017 AccessESP completed five projects, three in the Alaska North Slope and two offshore West Africa, all using the 3.75-in. Access375 system in 4.5-in. tubing. In addition, three Access375 wireline retrievable ESP systems were installed for a major operator in an Alaskan North Slope field in March 2018, according to a press release. The installations were in high-angle wells in 4.5-in. tubing. “The PMMs were installed in a single slickline run, made possible by their high power density,” the release stated. “Conventional motors would have been two to three times the length and weight, and operated with less efficiency.”

Ambyint
Ambyint provides artificial intelligence (AI)-driven artificial lift and production optimization systems. The company's operations combine traditional physics-based methods with modern AI and machine learning capabilities. Ambyint's AI algorithms work by training artificial lift systems using real-world data. Rather than telling the system what conditions to monitor, Ambyint’s system learns by analyzing all available data to identify parameters that are leading indicators of an issue, such as gas lock or paraffin buildup, that are not apparent to the average user.

The company has gathered nearly 100 million pump operating hours, or 45 TBs of high-resolution data from artificial lift and monitoring systems, 70% of which is derived from horizontal wells. Enabled by a large-scale training dataset, Ambyint’s system provides continuously updated and tuned models, which enable an inference engine to detect key production issues proactively including detection, characterization and prediction of well anomalies or prediction of wellhead leaks. By digitizing the visual input from millions of dynocards, Ambyint’s AI platform is able to perform micro-pattern analysis to diagnose downhole and surface anomalies and optimize well parameters. Ambyint’s system works for a variety of lift types, including sucker rod lift, progressive cavity pump and plunger lift.

Apergy
Apergy, a spinoff from Dover Corp., offers rod pumping systems, electric submersible pump (ESP) systems, gas-lift systems, hydraulic lift and pump services, progressive cavity pumps (PCP), drive systems and plunger lift systems. The company also provides automation offerings that consist of equipment, software and Industrial Internet of Things solutions for downhole monitoring, wellsite productivity enhancement and asset integrity management. Apergy has operations in eight countries.

Apergy comprises Dover Artificial Lift, Dover Energy Automation and US Synthetic and will continue to offer the same brands, which include Norris, Harbison-Fischer, Accelerated, PCS Ferguson, Norriseal-Wellmark, Spirit, Quartzdyne, Windrock and USS.

Dover Artificial Lift offers a complete suite of artificial lift products that includes ESP and PCP systems, remote monitoring and surveillance, hydraulic lift, gas lift, automation, rod lift, plunger lift and chemical injection.

In October 2017 Dover Artificial Lift announced a partnership with Liberty Lift Solutions. The two companies combined brands, products and services to offer the Liberty Lift Long Stroke (XL) Pumping Solution, which is designed to “provide a rod pump solution suited for work in deviated, deep or high-volume wells to manage production costs at an optimum level,” according to a press release.

In the same month, Dover Artificial Lift announced its acquisition of PCP Oil Tools in Argentina, according to industry reports.

Baker Hughes, a GE company
Baker Hughes, a GE company (BHGE), offers electric submersible pumping (ESP) systems, rod lift systems, progressing cavity pumping systems, horizontal surface pumping systems, gas-lift systems, surface electrical control systems, and monitoring and automation services.

The company's TransCoil rigless-deployed ESP system, developed with Saudi Aramco, is designed to allow operators to eliminate the need for a rig during ESP workovers, helping them to lower intervention costs and minimize deferred production. The system can be installed through 4½-in. production tubing, saving the time and money required to pull the existing completion, which is especially valuable for mature offshore wells, according to the company. By connecting an inverted ESP system directly to the power cable, the TransCoil system eliminates the
power cable-to-motor connection as well as an in-well electrical connection.

Saudi Aramco and BHGE have installed two TransCoil systems to date. In October 2017 BHGE completed the first offshore installation of the TransCoil system for an operator in a mature field offshore Malaysia.

The company recently commercialized its Magnetically Efficient permanent magnet motor, which is designed to improve efficiency by lowering ESP system energy consumption. It also delivers a higher power density, enabling operators to achieve a higher horsepower with the same motor or the same horsepower with a smaller motor, according to the company.

BHGE’s artificial lift systems group has 15 key manufacturing facilities located worldwide and four primary R&D facilities in the U.S. and Europe. BHGE’s Artificial Lift Research and Technology Center, which opened in 2014 in Claremore, Okla., allows engineers to create, develop and test solutions for production challenges and improve the reliability of artificial lift systems.

In December 2017 BHGE opened its Artificial Lift Center of Excellence in Dammam, Saudi Arabia. The facility will manufacture the full range of BHGE’s ESP portfolio and employ more than 100 technical professionals.

**Bluetick**

Bluetick offers oilfield automation and land management systems, including production reporting and field data capture tools that monitor artificial lift equipment, production wells and EOR injection wells.

Its remote monitoring and control (RMC) system is a full field data capture system with an app that runs on iOS-operated smartphones and 7-in. or 10-in. Android tablet devices. Among the production data available through the RMC system are oil run and water run ticket entries, well service and treatment data, tracking of shut-in status and history, well issue tracking data and the ability to track and manage well or pumper logs. The RMC system provides the ability for tank monitoring, remote shutdowns, well monitoring, compressor monitoring and electronic flowmeter monitoring. The system works through the integration of equipment sensors for pressure, temperature levels, wellhead controllers and other devices and transports data over cellular or satellite networks.

Other features of Bluetick’s RMC include the Alerts and Alarms Wizard, secure remote control, configurable charts and trends and calculated operations measurements. The RMC system also provides the ability to create unlimited custom reports for internal management, accounting, land department and regulatory agencies through a graphical user interface.

**Borets**

Borets focuses on the design, manufacture, sales and service of electric submersible pumping (ESP) systems. The company’s pumps include progressing cavity pumps and horizontal pumping systems. Borets also offers switchboards and variable frequency drives to control, protect and monitor ESP systems.

The company’s Wide Range Wear Resistant pump system, which is designed for the aggressive condi-
Increase production uptime, recovery and field valuation...

A unique and well proven rigless technology for through-tubing ESP conveyance, enabling O&G operators to maximize their asset value through increased well production uptime at a fraction of a conventional well intervention costs.

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tions often seen in unconventional wells, “operates reliably without a gas separator at 55% gas content at intake,” the company stated on its website.

In addition, the company’s ViewPoint downhole sensor is designed to fully capture the information from artificial lift systems to help minimize downtime, increase equipment runlife and optimize production, according to Borets. Because of the design of the sensor, a discharge sub or transfer line is not required to measure discharge pressure and/or temperature.

To ensure the maximum benefit of the EOR program, Clariant Oil Services identifies tools and systems to counter the negative impact of near-wellbore damage of production and injection wells. Crude oil flow can become restricted from the likes of paraffins, asphaltenes, scale and emulsions as it is transported to the surface, ultimately impacting oil recovery rates. Through the design and treatment of the near wellbore with LIBERATE Integrated Systems, Clariant ensures that the benefit of the EOR process is realized in additional injectivity and production at the targeted wells.

**Direct DriveHead Inc.**

Houston-based technology firm Direct DriveHead Inc. manufactures its driveheads for progressive cavity pump (PCP) operations as well as The Smart Pumper, which is an advanced version of Internet of Things (IoT) technology. The company also provides PCPs, wellhead fittings and valves, in addition to complete automation packages for the oil and water industries.

The Smart Pumper is a universal platform and hybrid technology that has high-speed global connectivity and an integrated processor to connect, protect and optimize operations. Its customizable web-based interface provides users with the capability to set up their interface and manage and control their assets located anywhere in the world quickly, according to the company. With its six forms of communication built into the platform, The Smart Pumper delivers a dependable and affordable IoT solution for the private and public sectors.

**DistributionNOW**

DistributionNOW (DNOW) offers custom rod pump systems and services, conventional and hydraulic pumping units, variable frequency drives, wellhead components, progressive cavity pumps (PCPs) and plunger lift equipment. The company also provides rod pump parts through Dura Products, a DNOW company.

DNOW offers complete systems design and performance analysis of plunger lift, rod pump or PCP wells using its design software (e.g., RODSTAR, SROD and C-FER PC-PUMP), technical expertise and experience.

The primary focus of DNOW’s artificial lift division is reciprocating rod pump systems and services in the major shale plays, supported by 35 pump shops in the U.S. and 18 in Canada. The company has in-house plunger lift technical experts and three PCP test facilities.
The company also provides “Best Practices for Rod Pumping Horizontal Shale Wells” workshops throughout the U.S. for its rod pump customers, where operators and DNOW rod pump experts can discuss specific issues and solutions.

**eLynx Technologies**

The eLynx software suite enables improved oil and gas production through SCADA monitoring, operational intelligence and predictive analytics. The company’s SCADA monitoring services offer end-to-end security, field-hardened sensor and cloud communication networks, data normalization and custom user configurations.

eLynx’s operational intelligence systems help users assess wells, identify production opportunities or high-priority issues, and focus on solving problems. Its predictive analytics operations offer digital twin monitoring and data analytics that can help improve production and cut costs by suggesting optimal well settings and forecasting looming problems in time to take action.

The company’s operational intelligence site, used in addition to SCADA, delivers visibility, productivity and insight for production teams. It speeds decisions and sharpens insight for users in the oil field. eLynx’s data scientists use SCADA readings to clarify what is happening downhole. Armed with clean data, eLynx’s systems give engineers new insight into optimizing well operations and predicting future well behavior. The company’s digital twin models can simulate and test a higher number of combinations of settings. As a result, users will discover simple ways to increase production quickly, usually at no additional cost.

**Emerson**

Emerson offers artificial lift optimization software that constantly responds to constraints and changing well production compositions.

The company’s Dynamic Lift Optimization (DLO) system automatically determines and controls set points of the lift system in real time. The lift optimization system enhances augmented static theoretical models and automatically operates lift systems with the most limiting set of constraints. It allows changes to be made to the system configuration when needed while distributing lift energy in real time to the wells that will benefit most. In one example of Emerson’s DLO, a model of an offshore platform 15 years into its 25-year life span experienced a dramatic change in its water cut, which resulted in the platform’s water handling system at capacity. The system was optimized by placing actuators on each valve, allowing quicker test cycles through each of the seven wells. The test separator was replaced with a Roxar multiphase flowmeter, which allowed quicker testing of every well in sequence and on a daily basis. The result was quicker optimization and automation of well testing as well as a 4% to 14% improvement in production on the platform. That improvement would result in a 400-bbl/d to 1,400-bbl/d increase in production. For onshore operations, DLO contributes to improved production efficiencies as well as reducing lease operating expenses.

**Extreme Telematics Corp.**

Private engineering firm Extreme Telematics Corp. (ETC) specializes in designing and manufacturing low-power, extreme-temperature-certified electronics for industrial applications and hazardous locations. ETC’s plunger lift product line includes the Cyclops plunger arrival sensor, Sasquatch plunger velocity sensor, the ALiEn² plunger lift controller and the Iris wireless bridge.

ETC’s most recent development, tracking kinetic energy of plunger arrivals with Sasquatch, generates alarms on hard and dangerous impacts at surface. This helps producers use predictive maintenance to extend the lifespan of wellhead equipment, increase safety and reduce trips to the site, according to the company.
The business expanded to include electronic product design services in 2016, offering a wide range of specialized skills in electronic hardware, firmware, mechanical, and test design and implementation.

**Flowco Production Solutions**

Flowco Production Solutions offers a full range of artificial lift services, including gas-lift and plunger lift systems.

Among the gas-lift services offered by Flowco are continuous flow gas lift, intermittent gas lift, casing (annular) flow, a packer bypass system (PBS), a micro-annulus crossover system and an increased annular velocity system. The PBS combines a conventional gas-lift system with a packer.

The micro-annulus crossover system is offered in both horizontal and vertical systems. The horizontal micro-annulus system utilizes a crossover flow adapter and mini wellbore below the packer, a method that allows deeper point of gas injection compared to traditional gas-lift systems. The vertical micro-annulus system is an option for wells with low reservoir pressure where it is important to isolate gas-lift pressure from the perforations.

The company’s plunger lift applications include traditional lifts and continuous flow plunger lifts. Flowco’s line of plunger lifts includes the Rage bypass plunger, the Spin-Fury plunger and the Sure-Seal plunger. The plungers are suited for wells that recently have been completed, with sand and/or scale problems and for horizontal applications or deviated wells.

**Global Production Solutions LLC**

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

GPS developed a program to optimize water transfer and disposal costs. In testing, the company said it has reduced power usage by up to 50% while also reducing mechanical wear. Additionally, the company’s reciprocating ESP system consists of a modified conventional ball and seat pump driven by a reciprocating downhole motor, combined with specific variable speed drive technology. This unit can be applied where flow rates are below conventional ESP systems, have a high gas-liquid ratio and high dogleg severity, and/or in horizontally completed wells where traditional rod-driven systems are inefficient and ineffective, according to the company. The unit also can be applied in low-profile locations or where a small footprint is required.

GPS also has developed a proprietary algorithm to allow greater bottomhole pressure (BHP) drawdown while maximizing inflow potential as compared to conventional gas lift. The system extends the application to lower BHP wells that previously were not considered viable gas-lift candidates and were produced inefficiently through other forms of artificial lift.

**Halliburton**

Halliburton’s artificial lift portfolio includes electric submersible pumps (ESP), horizontal pumping systems (HPS), progressive cavity pumps and 24/7 well monitoring. The company also provides artificial lift installation, maintenance, repair and testing services.

In July 2017 Halliburton acquired Summit ESP, a provider of ESP technology and services. Summit ESP technologies include the Tiger Shark, XRange and XRange Defender pump lines, Corsair motors, and a wide range of products and services to meet ESP and HPS needs.

“Combining the best technologies, market research and customer feedback, the expanded portfolio offers solutions for challenging applications with the presence of sand, corrosive compounds, high temperatures and gas-plugging issues,” the company said.
The new artificial lift systems are designed to meet the challenges for unconventional and mature plays in the U.S. and abroad.

The company’s latest technology is the SandRight, a solids fallback preventer designed to deter damaging solids from entering an ESP during power shutdown events, preserving the ESP’s life.

Halliburton Artificial Lift provides customized solutions and ongoing support through real-time collaboration.

Liberty Lift Solutions LLC

Liberty Lift provides artificial lift products including long stroke pumping units, beam pumping units, gas-lift systems and hydraulic jet pump units.

In 2017 Liberty Lift developed HyRate, a new technique that is designed to address and improve gas-lift shortcomings and facilitates annular and tubing lift without a workover rig. The technique “incorporates an externally mounted assembly with both special capsule valve mandrels that allow annular flow and conventional mandrels permitting assisted tubing flow,” the company stated on its website. “The conversion from one lift method to another can be accomplished quickly and efficiently with the only use of a wireline to pull or replace the bottom tubing plug.”

In addition, in March 2017 the company added a 366-in. stroke length version, the XL 366, to its long stroke rod pumping unit product line. The unit can detect potential operating abnormalities, pausing or stopping the unit when alerted, and it also incorporates a clean oiling system for internal parts and safety features to protect operating personnel and the environment, according to the company.

Liberty Lift also works with JJ Tech to offer hydraulic jet pump units that include a surface power fluid system, prime mover, surface pump and downhole jet pump.

Lightning Production Services

Lightning Production Services manufactures continuous rod and liner tubing, coiled rod services, and installation and welding of continuous sucker rods.

The company’s LightningRod continuous rod eliminates all the couplings along the wellbore except for the top connection to the polished rod and the bottom connection to the pump itself. By eliminating the couplings along the wellbore, the pressure points between the rods and the tubing are minimized by spreading the pressure along a longer contact area of the rod and tubing. The result is longer run lives of both the rods and the tubing, which inherently increase the mean time between failures, according to the company.

Lightning Production Services’ LightningFlo thermoplastic tubular lining is mechanically inserted and bonded to the inside diameter of the tubing joint allowing the liner to be installed inside of both new and used tubing. The lining provides protection from frictional wear and corrosive effects of the caustic downhole environment.

The company’s service offerings include maintenance and repairs on wells with conventional or continuous sucker rod and other types of artificial lift. The company also provides pump changes, broken rod maintenance, pulls and flushes, polish rod changes, packing or stuffing box changes, drive head maintenance and fishing services.
Materion
Materion has engineered its ToughMet 3 Sucker Rod Couplings for shale wells operating on an artificial lift rod pump. The couplings help eliminate production interruptions caused by sucker rod coupling and production tubing failures in deviated shale wells. The ToughMet 3 alloy was originally engineered for oilfield applications and has more than 20 years’ use in directional drilling tools and other oilfield equipment components. The couplings resist mechanical wear, thread damage, corrosion and erosion.

Materion’s ToughMet 3 Sucker Rod and Valve Rod Guide Bushing Couplings eliminate the most common causes of failure in wells operating on artificial lift. (Image courtesy of Materion)

Materion’s ToughMet copper-nickel-tin alloys are spinodally hardened to provide attributes beyond those typically found in high-strength copper alloys. Those attributes include high impact and fatigue strength; corrosion, erosion and wear resistance in most oilfield environments; control fluid compatibility; magnetic transparency; and anti-friction and anti-galling characteristics. The ToughMet 3 alloy resists hydrogen embrittlement, chloride stress corrosion cracking and moderate hydrogen sulfide environments.

A full range of ToughMet couplings are available from local inventories for just-in-time delivery, including sucker rod couplings, cross-over couplings, polished rod couplings, and the company’s new valve rod guide bushing coupling.

MRC Global
MRC Global distributes pipe, valve and fitting products and provides services to the oil and gas industry. The company’s upstream market concentrates on products used during the exploration, completion and production of oil, gas and NGL.

MRC Global offers its products to production crews to move hydrocarbons into gathering systems or pipelines for processing. The company also provides value-added services such as project trailers, kitting of well hookup materials, integrated supply and valve actuation.

Its product lines include high-density polyethylene and fiberglass piping, valves, lifting and handling products, measurement devices, pumping systems—including rods and rod pumps—pumps and accessories, tanks and separators, as well as drilling and production tools and wellheads, including casing heads, tubing heads and casing supports. MRC Global’s line of drilling and production equipment includes downhole equipment, fishing tools, packers, pit liners and tubing handling equipment. The company’s array of valves includes ball, butterfly, plug, check, multi-turn, subsea and specialty valves.

National Oilwell Varco
Artificial lift technologies provided by National Oilwell Varco (NOV) include rod pumping systems, progressing cavity pump (PCP) systems, tubing rotators and automation.

NOV’s rod pump systems include hydraulic pumping units, rod and tubing rotators, and downhole rod pumps and components. The rod pump systems are designed to have a smaller footprint and quick installation time, according to the company, while increasing personnel safety and improving control over oil and gas production. Additionally, NOV provides a full suite of production service hookup equipment for PCP and rod pumping applications, with design
A FIELD PROVEN
MULTIPHASE
SUBMERSIBLE
PUMP

Sand
Up to 20% by volume

Viscosity
Tested over 13,000cp

Gas
Up to 90% GVF

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focused on achieving better pressure control and wear prevention while maximizing production and minimizing downtime.

The company’s PCP systems are designed for use in both oil production and dewatering applications. A PCP controller, part of a line of automation products, ensures greater operational efficiency and better control of PCP artificial lift systems, integrating into existing networks to simultaneously monitor pump performance and control on/off cycles. The system minimizes downtime and optimizes well performance by automatically changing pump speed, according to the company.

**Novomet**

Russia-based Novomet manufactures electric submersible pump (ESP) systems. The company’s technology includes slimline ESPs capable of fitting inside of 4-in. casing, PowerSave ESP systems to reduce power consumption by up to 50% and products for wells with high gas-oil ratios, scale, solids and H₂S.

The company’s ESP offerings include downhole equipment, surface equipment, and scale preventers and filters. Other artificial lift products include gas-handling, scale and solids management and extreme H₂S environment solutions. Novomet also offers a rigless ESP system without tubing, a bypass (Y-tool) system and a progressing cavity pump with topside and downhole motors.

In March Novomet developed an abrasion-resistant ESP system with an expanded operating range, according to a news release. “Due to the expanded operating range, it is now possible to reduce the standard range of 362 and 406 series ESP systems with flowrates from 10 to 350 sq m/d from 13 to 3 models. In addition, ImpalaESP is designed to operate at 3,000 rpm and may be driven by an induction motor with a conventional VSD,” according to the press release. “As a result, operators will be able to reduce inventory levels, optimize the ESP application process and ultimately cut total costs of oil production.”

Novomet has service centers in 12 countries outside of Russia. The centers offer a variety of ESP services for well maintenance that include sizing, inspection, transportation, assembling/disassembling, testing and supervising. In November 2017 the company opened its latest office in Wyoming.

**PetroCloud**

PetroCloud specializes in cloud-based solutions for security, surveillance, remote monitoring and control of critical assets in the oil and gas industry. These technologies enable users to remotely access, view and control their site’s equipment using their mobile phone or computer and notify them of critical events.

PetroCloud’s remote surveillance system provides high-definition cameras with streaming video, night vision, thermal imaging with digital snapshots and 24/7 recording. The company’s security products provide remote gate access control with video and keypad restricted entry. PetroCloud’s SiteWatch offering includes end-to-end perimeter coverage using laser tripwires. These systems allow users to receive notifications whenever workover rigs, transportation trucks or others arrive or leave a site.

PetroCloud’s real-time data acquisition and analytics provide bi-directional control of equipment at even the most remote locations. (Photo courtesy of PetroCloud)
**Priority Artificial Lift Services LLC**

Priority Artificial Lift Services offerings include gas-lift, plunger and completion tools and technologies. The company’s services include equipment installation, production optimization, troubleshooting, production analysis, nodal analysis, well modeling, consulting, engineering, training and manufacturing.

The company uses its conventional high-pressure gas-lift equipment (rated to 10,000 psi) to accommodate gas-lift installations on initial completions and in highly developed areas where high-pressure offset fractures are likely. As the wells deplete, Priority has a variety of gas-lift products to accommodate installation of gas-lift valves deeper into the wellbore to maximize production. Typically, the deeper gas-lift system is accompanied with a plunger to create a hybrid gas-lift and plunger lift system. This hybrid system is designed to reduce flowing bottomhole pressure and increase gas-lift efficiency.

Priority has nine service locations and a manufacturing facility in the U.S.

**RFG Petro Systems**

RFG Petro Systems manufactures sucker-rod guides (centralizers), guided couplings and stabilizer bars using its MP polymer. The MP polymer offers extreme wear and chemical resistance and is mechanically and dimensionally stable in a wide temperature range up to 260 °C (500 °F). This technology provides RFG Petro Systems rod guides, guided couplings stabilizer bars with extended product life and helps to protect against tubing wear.

RFG’s MP Rod Guides are molded directly onto the sucker rod to ensure the guide stays in place to protect against rod-on-tubing wear. Its engineered guide spacing allows both the rod and coupling to remain off the tubing wall. The RFG Box-Guide is a guided coupling that allows the consumer to use the MP technology to gain protection in a field-installed guide to protect against coupling-on-tubing wear.

RFG Petro Systems sucker-rod guides are manufactured using MP polymer, making the tool resistant to high temperatures. (*Image courtesy of RFG Petro Systems*)

**RigNet**

RigNet provides systems ranging from fully managed voice and data networks to advanced applications that include video conferencing, crew welfare, asset monitoring and real-time data services, system integration and onsite maintenance to enhance workforce productivity, safety and security at remote sites. From near-urban area deployments with LTE coverage to remote areas where satellites are the only option, RigNet provides multi-network connectivity, coupled with a host of hardware and application services that facilitate end-to-end visibility and management of cost, devices and operations.

With RigNet’s Inteliie machine learning layer, the company also can drive operational efficiency and growth through smart data analytics and real-time decision-making.

The company’s “Life of the Well” services in major shale plays cover an area of 150,000 sq miles and feature nearly 60% of the land-based drilling rigs in the U.S. RigNet can install both temporary and permanent, high-speed network infrastructure to rigs that allow operators and service companies to connect to their corporate network, business operations and crew securely from the time the rig arrives at a location to when it leaves. These networks are protected by RigNet’s Cyphre hardware-based, key management and orchestration systems.

**Rockwell Automation**

The Rockwell Automation OptiLift artificial lift system provides end-to-end smart field operations to oil and gas operators globally. The OptiLift Intelligent Net Oil Computer (iNOC) is an engineered system that offers remote connectivity, enhanced visualization, optimized test capacity and improved test duration. The iNOC system is part of a fully connected oil field. The iNOC system improves well
test duration with oil and water volume prediction for 24 hours during any test period. The system installs in the “liquid leg” of a two-phase test separator and can support tests on up to seven wells. The OptiLift rod pump controller is engineered to help maximize return on investment and achieve sustainable operations and operational excellence. This on-site controller can help provide the accurate and flexible control necessary for well production optimization. The control technology also can be packaged with an Allen-Bradley variable frequency drive to create an integrated system for speed control in rod pump applications. The OptiLift virtual flowmeter is designed to optimize production and reduce costs. Engineers are able to view the pressure, temperature and flow rates in real time, which enable them to adapt quickly to uncertain situations. These systems form part of the broader ConnectedProduction system, which has been designed to visualize and optimize onshore oil and gas production from wellhead to point of transfer.

**Schlumberger**

Schlumberger’s artificial lift offerings include electric submersible pumps (ESP), gas lift, horizontal surface pumps, sucker rod pumping units, progressive cavity pumps, production lifting services and real-time monitoring and optimization. The company offers an integrated, field-proven lift platform that includes REDA ESP systems and Camco gas-lift and subsurface safety systems.

In January 2017 Schlumberger acquired Peak Well Systems, a specialist in the design and development of advanced downhole tools for flow control, well intervention and well integrity, according to a press release. The addition of Peak’s mechanical and remedial solutions for cased-hole well intervention strengthens the Schlumberger Production Services portfolio with a broader offering of mechanical services to its global customers.

Schlumberger commercialized its Lift IQ production life-cycle management service in March 2017. This new service offers monitoring, diagnostics and optimization of artificial lift systems in real time. The Lift IQ service taps into the engineering, manufacturing and surveillance expertise of Schlumberger with access to global service centers 24/7 year-round, according to the company.

In late 2017 Schlumberger launched its LiftSelect strategic production planning service. It simplifies the process of selecting the artificial lift strategy that will best achieve production goals, based on objective analysis of economic and technical criteria. The service uses available field and reservoir data to model well behavior and maximize asset value by reducing the cost per barrel of hydrocarbon production.

Later in the year, Schlumberger and Production Plus Energy Services formed a joint venture to develop the HEAL system technology and business. The HEAL horizontal enhanced artificial lift system conditions the produced fluid stream, mitigating slug flow to extend natural flow and increase productivity over the life of the well.
Sercel-GRC

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

In 2017 Petrospec Engineering Ltd. and Sercel-GRC released the Sensor-Tube ESP system, a new advancement in ESP monitoring, according to Sercel-GRC’s LinkedIn post, “Use of Sensor-Tube ESP can predict ESP failures for advanced planning of workovers to minimize downtime.”

In addition, Sercel-GRC’s Spy Pro waterproof ESP gauge is designed to let users continue monitoring well performance when the motor connection is submerged in water, resulting in unbroken access to vital data needed, according to information on the company’s website.

Moreover, the company’s Data Pro universal datalogger is a high-performance configurable surface acquisition unit that features datalogging, real-time graphing, historical graphing, Modbus communication and gauge configuration, according to a company product sheet.

Silverwell

Silverwell’s Digital Intelligent Artificial Lift (DIAL) system addresses the problem of gas-lifted wells operating in a nonoptimal state. Silverwell’s DIAL system allows gas-lift injection rates to be adjusted and monitored in real time downhole. The system is fully digital and electronically controlled and monitored from the surface via a permanent cable. It replaces conventional gas-lift mandrels and valves with permanently installed DIAL units. This eliminates wireline interventions and workovers to adjust gas-lift injection rates, along with the associated operational risk, costs and production deferment, according to the company. Silverwell can configure the DIAL system onshore or offshore to suit all gas-lift completion architectures—dual string, in situ, intermittent and annular flow. The DIAL in-well unit features up to six injection orifices, each individually controlled from the surface providing multiple available injection rates. When combined with annulus and tubing pressure and temperature sensing capability at each DIAL station, the operator can implement data-driven...
ARTIFICIAL LIFT: KEY PLAYERS

optimization decisions as well conditions change without incurring the risk and cost of intervention. DIAL overcomes the limitations of existing production and completion equipment, eliminates well intervention and enables an economically enhanced approach to gas-lift production optimization, according to the company.

**Superior Energy Services**

Superior Energy Services offers drilling products and services, onshore completion and workover services, production services and technical solutions. Superior’s Gas Lift division includes onshore and offshore gas-lift equipment. The company provides fit-for-purpose artificial lift offerings through its engineering, optimization and troubleshooting techniques, manufacturing and value-added approach.

Superior also offers gas-lift design, troubleshooting and optimization classes in the field and in the office for engineers, pumpers and interns. Superior also applies the latest technology available for product innovation to assure exceptional quality and reliability while offering proprietary design software to get the most precise designs, according to the company.

The plunger lift group works alongside the gas-lift group to offer plunger lift as well as gas-lift-assisted plunger lift systems. Superior’s plunger lift group manufactures lubricators with ratings of 3,000 up to 15,000; a multitude of plungers, most notably being the dart-style plunger and the Pacemaker plunger; and an assortment of bottomhole assemblies including multistage offerings. The manufacturing team uses well modeling software, 3-D printing and computational fluid dynamics to provide technical solutions. The plunger lift field team provides technical training on site including well model and optimization classes as well as using echometers in the field. With the ability to couple the gas-lift and plunger lift systems in one gas-lift-assisted plunger lift, Superior can offer an artificial lift tool for the life of almost any well.

**Tenaris**

Tenaris, a supplier of tubes and related services, offers sucker rods and has manufacturing facilities in 17 countries.

In 2016 the company introduced Rig Direct, a services-oriented model that offers customers the direct delivery of products and services, including technical consulting, pipe management and onsite field service assistance.

Tenaris’ mills, including its new seamless plant in Bay City, Texas, which started production late last year, supports the services model by synching the manufacturing and delivery of products with the customers’ drilling operations.

The company’s AlphaRod sucker rod series feature rods manufactured with enhanced steel grades that are designed for a long life in demanding requirements, according to a March 2017 press release. The AlphaRod series includes two steel grades, which cover a wide range of applications. The AlphaRod HS (high strength) and AlphaRod CS (critical service) are designed to handle increased service loads and overcome fatigue and corrosion-fatigue problems in beam pumping and progressive cavity pumping applications.

In addition, Tenaris’ BlueRod premium sucker rods have a resistant connection designed for high loads, and “the connection improves the rod’s fatigue life and ensures excellent field performance,” according to the company’s website.

Tenaris’ HolloRod series hollow sucker rods are designed “to increase the reliability of progressive cavity pumping operations and reduce operating costs,” the company said.

**Unico**

Unico Inc. provides variable frequency drives and controls for electric submersible pumps, hydraulic pumping units, progressive cavity pumps (PCP) and sucker rod pumps. The company’s mechanical lift systems include its linear rod pumps, PCPs, crank rod pumps and hydraulically actuated pumps.

Unico’s UWS Hatch Sense system, together with a Unico UWS Gateway, allows the status of tank hatches and other safety mechanisms to be remotely monitored by the GMC system or a SCADA system.

In addition, Unico’s SRP Well Report provides well operators with one-button access to surface and
ARTIFICIAL LIFT: KEY PLAYERS

downhole pump DynaCards and other data stored in a well powered by a Unico artificial lift drive. Operators can generate a complete four-page well report, produced in as little as 25 seconds, at the click of a button, according to the company.

The company’s Synthesis intelligent pump controller simplifies pumping systems by integrating essential motor, logic and process control functions into a single economical unit. It is designed to provide superior pressure, flow or level control, optimal efficiency and comprehensive protection for the pumping system.

Unico is a wholly owned subsidiary of Regal Beloit Corp., a worldwide manufacturer of mechanical and electrical motion-control products.

Valiant Artificial Lift Solutions
Founded in 2016, Valiant Artificial Lift Solutions is an independent oilfield service company that provides downhole and surface pumping solutions that include electric submersible pump (ESP), progressing cavity pump (PCP) and horizontal pump systems. Valiant also offers services ranging from application engineering, equipment sizing, monitoring, maintenance, installation and repair.

The company’s ESP systems support flow rates up to 35,500 bbl/d and can be customized for production in abrasive or high gas content applications. For production in high-viscosity environments, Valiant provides, installs and services rod-driven PCP systems and rodless electric submersible PCP systems.

Valiant’s Aquarius horizontal pumping systems are designed to produce up to 49,200 bbl/d (1,435.2 gal/min) at speeds up to 1,500 hp for surface pumping applications.

Valiant started with a manufacturing and service center in Midland, Texas, and since then has expanded throughout North and South America. In September 2017 Valiant announced the opening of a 60,000-sq-ft facility in Bogotá, Colombia, built to provide artificial lift products and services to operators in Latin America. The company also opened two new facilities in January 2018 in the Midcontinent region. The Midcontinent locations are dedicated to ESP manufacturing, testing, repair, cable service and horizontal pumping solutions, according to a press release.

Veretek
In June 2017 Elite Multiphase Solutions changed its name to Veretek as part of a rebranding campaign. The private company provides its V-Pump downhole pump technology, remote monitoring of the V-Pump and real-time operating recommendations to operators.

Veretek’s multiphase submersible V-Pump is designed to improve production economics in wells in which electric submersible pumps (ESP) struggle with multiphase conditions that include combinations of sand, gas and high-viscosity oil. The V-pump is offered as an alternative to ESPs and features the same dimensions, flange and shaft connections as ESPs and is operational with any service provider’s conventional ESP motor, seal, cable and sensor configuration. Veretek’s V-pump can lead to fewer well interventions and offers the ability to continue pumping through multiphase conditions as well as a wider operating window through broader speed ranges. The tool improves uptime with less tripping of the system and operates in wells deemed unpumpable with conventional ESPs. The V-pump features a helicon-axial pump design consisting of a rotor and stator and can increase the operating range with higher speed permanent magnet motors. The pump offers the
ability to reverse pump to flush and can handle up to 100 times the amount of sand as conventional ESPs, according to the company.

In a Permian Basin case study, a major operator suffered an ESP failure within three weeks of installation due to sand erosion. It was eventually pulled and replaced with a V-pump. The pump produced 60% more fluid and sustained high sand production and operated trouble-free for one year.

Weatherford
Weatherford provides products and services for every form of artificial lift from reciprocating rod lift to progressing cavity pumping. As an end-to-end production solutions provider, the company also provides production optimization hardware, sensors, software and automation technologies.

The company’s WellPilot ONE universal controller centralizes management of all oilfield equipment to a single piece of hardware. This next-generation controller/remote terminal unit provides automation for the entire field and enables seamless transitions throughout all production and lift phases, which significantly reduces the total cost of ownership.

Another artificial lift technology is the sand-tolerant pump (STP), an alternative to standard rod pumps in wells with high sand production. The STP can perform in temperatures up to 182 °C (360 °F) and has a self-cleaning slippage-fluid filter to keep damaging sand out of the plunger-barrel sealing surfaces.
MAXIMIZE DRAWDOWN MINIMIZE COSTS

The HEAL System™: The Foundation for Efficient Artificial Lift in Horizontal Wells

Horizontal wells are known to have production challenges as a result of inconsistent flow, damaging solids, and gas interference. Maximizing drawdown through the lifecycle of these wells often requires complex and expensive artificial lift strategies.

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

- Install for the life of the well
- Offers frac-hit protection
- Simplify transition to artificial lift
- Accelerate transition from gas lift to rod pumping
- Improve performance in any artificial lift system
- Reduce capital investment and operating expense
- Proven technology in 250 installs in 37 formations

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info@healsystems.com
In addition, with couplings only at the top and bottom of the rod string, Weatherford COROD continuous rod minimizes the potential for rodstring failures and costly interventions, according to the company’s website.

**WellAware**

WellAware provides Industrial Internet of Things (IIoT) production management and chemical management systems designed to help E&P companies capture and use their data for peak operating efficiency. The company’s offerings include data collection, exception-based monitoring and actionable insights.

WellAware’s system captures critical production data via native iOS and Android apps that work without cellular connectivity. Data captured include measurements and well, pipeline, chemical, water, hazardous gas and flare information. The system’s management operations allow user-configurable grouping of assets as well as list- and map-based visualization of real-time assets and configurable alarms. The mobile app enables rapid alarm acknowledgement, troubleshooting solutions and resolution.

WellAware’s analytical capabilities include role-based dashboards for field personnel, engineers and executives, along with customized reports without IT or vendor assistance.

WellAware’s IIoT system’s capabilities include full-stack data intelligence, eliminating the need to deal with separate vendors for network, automation and software. WellAware reported that after implementation of its management system, a major E&P company reported reducing downtime by 75% to 80% and improving operating efficiency by more than 50%.

**Wellflex Energy Solutions**

Wellflex Energy Solutions provides oilfield equipment engineering and design, fabrication and manufacturing, installation and construction, and maintenance management services. The company also offers full-service automation, control systems and fabrication. Its capabilities include engineering and integration of automation, control, analytical and information systems. Additionally, Wellflex’s fabrication facility designs, manufactures and integrates a selection design programmable logic control panels, motor control center buildings, control consoles, cabinets, marshaling/junction boxes, relay panels, analyzer sampling systems and various industrial panel applications.

The company’s ModFlex process can help improve the total cost of ownership of Wellflex’s equipment through modularizing a pad site in the company’s facility, according to the company. WellFlex said its ModFlex process improves the predictability of scheduling and costs associated with pad site construction due to the reduced field labor required for installation and the standardization of multiwall pad sites. The company reported that construction of an eight-well pad through its ModFlex process was reduced from 25 days to five days, resulting in a cost savings of $150,000.

Its products include flowback systems, pig launchers and receivers and piping and pumping systems. Liquid processing systems include hybrid separators, crude treaters, sand separators, vapor recovery units and allocation/metering packages.

**Zedi Inc.**

Zedi is a technology and services company that offers software, automation, artificial lift, measurement, laboratory and field solutions for production and operations.

The Zedi SilverJack 6000 artificial lift system is pictured in a tandem setup. (Photo courtesy of Zedi)

The Zedi SilverJack 6000 artificial lift system is an advanced hydraulic pumpjack with a local graphics-based optimization controller combined with Zedi Access, a web-based data management system that provides remote monitoring, alarming and control. This allows both local and remote optimization and the resolution of common rod pumping problems without site visits or labor-intensive manual processes.

In addition, Zedi SCADA is a web-based open system that works with any digital monitoring hardware to deliver real-time operational data, allowing users to remotely view and control field equipment including any artificial lift solution.
When it Comes to Artificial Lift

TWO HEADS REALLY ARE BETTER THAN ONE

The combination of Summit® ESP’s technical service, quick response, and intensive collaboration, coupled with the experience, support, and strength of Halliburton, means you now have the opportunity to get more from your artificial lift provider. Our superior electric submersible pumps and horizontal pumping systems employ next generation technology that can be adapted to individual customer needs. In unconventional wells, mature fields, or wherever, working with us gives you a better chance to maximize production while minimizing costs. Contact us today.

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The Future is Near

Artificial lift technology continues to mature on all fronts as contractors target the sweet spots.

Better data allow for better decision-making. This could be today’s mantra for the burgeoning artificial lift segment of the upstream oilfield services sector. However, the roadmap to better data is sprinkled with its fair share of potholes, detours, shortcuts and unexpected maintenance. Better data comes from reliable equipment, and service companies have been charged to keep lift systems—like electrical submersible pumps (ESPs)—in top form for longer. Better data also come from the ability to collect and analyze at unprecedented volumes, asking more of conventional hardware like well pad controllers in expanded roles throughout the oil field. The quest for better data also has an expanding footprint, beyond single-well pads to the now conventional 20-plus well pads that are spreading across the onshore unconventional plays in the U.S. Better data would also benefit from new levels of standardization—a buzz term that has been around the oil patch for as long as many can remember. With workflows and implementations varying from operator to operator, the standardization quest is daunting.

“Over the years, as our different customers have either put in new systems themselves or acquired systems through merger activity or experimented with new technology themselves—such as new artificial lift technologies and new automation control systems on the well pad—they tell us they see several different styles implemented for similar work,” said By Blake Wright
Contributing Editor

Rockwell’s Well Manager is a pre-engineered solution that integrates all artificial lift operations. It can support small or large multipad well sites with real-time data from across an oil field. (Image courtesy of Rockwell Automation)
Zack Munk, upstream oil and gas business development manager for Rockwell Automation. “When a company is acquired and they’ve used a certain type of hardware for automation control, the purchasing company basically has to re-teach their technicians how to work with the new equipment. The push for standardization remains. Too many systems eventually will cause a problem with maintenance which ultimately adds to the overhead of these assets.”

Today’s data volumes are also quite staggering. Operators have data coming in from real-time sources as well as data from historical sources. Many times there will also be modeling software involved as well as some other production databases. Being able to visualize all of this data so that it can be accurately analyzed and result in the best decisions is pushing some operators out of their comfort zones. As the data glut looms, the goal remains to efficiently navigate this expanding digital roadmap to ensure best performance from lift applications throughout the life cycle of individual wells as well as life of field.

**AI and the predictive challenge**

One of the leading-edge technology pieces to the data puzzle is the expanding use of artificial intelligence (AI) and automation to predict equipment longevity. Once operators can become more predictive and less reactive when it comes to equipment maintenance and failures, downtime will be reduced.

“There has been a growing trend towards proactive field management, and we are helping clients plan their lift strategy and how they manage their assets over time,” said Gregg Hurst, global business director, artificial lift at Weatherford. “Our ForeSite production optimization platform is an example of how predictive analytics enable better life-of-well planning. It is an advanced analytics tool built specifically for production optimization. ForeSite collects and leverages data from across the asset, which allows clients to anticipate problems before they occur. The system learns from historical and real-time data and offers insights to improve current and future decisions. The platform also gives clients a standardized workflow that helps them to manage their daily activity through simple-to-use dashboards. They can even view and manage their dashboards and drive their priorities from a mobile device.”

Introduced in May 2017, ForeSite processes real-time sensor data from every corner of an asset to

Weatherford’s ForeSite platform provides well-management tools to help operators pinpoint and prioritize production issues. *(Image courtesy of Weatherford)*

“Ultimately operators are interested in increasing the net present value of their assets. This is done either through increasing the production from an asset or reducing their total cost of ownership. Today this is done primarily through manual processes dependent on strong technical expertise, which does not scale well to be efficient across thousands of wells,” said Lawrence Camilleri, artificial lift technical director, Schlumberger. “Through digitization, automation and the Industrial Internet of Things (IIoT) we are able to deliver both production increase and reduction of total cost of ownership at scale and with repeatability. An example of this is the new automated ESP flowrate calculation platform from Schlumberger, which uses IIoT technology to automatically detect substandard conditions in an ESP operation (pump operating point and health), ensuring runlife is increased and unwanted shutdowns are avoided. The platform also provides real-time power optimization for ESPs during operation. Most importantly, real-time data enables high-frequency downhole flowrate measurement, which provides operators with well inflow performance relationship (IPR) during operation and pressure transient analysis without the need for buildups. This is critical for optimizing well inflow by, for example, identifying opportunities for increased drawdown and stimulation. We have only touched the surface of what we can do from an automation perspective in the artificial lift space, and the platform is the foundation for future enhancements.”
provide a clear analysis of the reservoir, well, field and surface network. This single platform provides engineering models and predictive analytics to help operators evaluate, predict and respond to ever-changing conditions. With an enterprise-wide approach to well optimization and real-time monitoring, ForeSite is designed to allow clients to quickly identify, prioritize and service underperforming wells. These features help operators to reduce production losses and downtime, while improving their bottom line.

Predictions regarding artificial lift equipment are something that Rockwell demonstrated at its Automation Fair in 2017. The company touted its ability to show predictive analytics on an ESP system as the data was coming in real time. Utilizing its Connective Production, Rockwell was able to pre-process and analyze the data as they came into the system, predict the equipment state of the pump downhole or its future state, and alert operations and maintenance personnel based on what kind of event was happening, be it a locked pump or maintenance issue.

“Can we use AI to help us predict optimum production out of a gas well, so we don’t over-produce and damage the well?” Munk asked. “Customers are also looking at better modeling—downhole, future production—as they have more accurate models they can make better decisions. Another thing I think we’re going to need is high-integrity data and better communication methods at the well site. The AI will only be as good as the data provided to it. Things like MQTT [Message Queuing Telemetry Transport]—another buzz word around industry—will help because they provide a layer of integrity in the data that is getting to our data packages.”

Schlumberger sees a near-term future where integrating software technologies with IoT (Internet of Things) capabilities will enable automation of production enhancement. “Today, the algorithms running on these devices are relatively rudimentary, and the untapped promise for this technology will be game-changing,” said Camilleri. “Prognostic health management of lift systems to predict failure—and thus avoid unwanted downtime waiting on rigs for intervention—is one such promise. Another one that is just around the corner is automated event detection and diagnostics, which will automate surveillance and thereby improve runlife and uptime in fields with a large number of artificial lift systems. The automation is based on years of development work in the area of data analytics, which provides the tools to correctly diagnose a wide range of data signatures characterizing mis-operation.”

Schlumberger is developing software tools for both prognostic health and automated event detection and diagnostics that will be part of the Lift IQ production life-cycle management service, which provides a range of real-time services from the very simple data visualization all the way to the more complex analytical tools under a single umbrella.

**New developments in ESPs**

Halliburton has focused this past year on developing more reliable and efficient ESPs. The major challenges that an ESP faces in most unconventional wells are high temperature, sand content and corrosion. All of these issues can cause a pump to malfunction downhole, thus leaving the operator with the expensive proposition of rig-based retrieval, repair and the hit to the bottom line caused by the unplanned downtime. The company’s July 2017 acquisition of Summit ESP has effectively expanded its capabilities.

“With sand, one of the issues is not only erosion, but plugging the pump, especially when you have multipump shutdowns, you have fall downs,” said Francisco Romero, artificial lift global business development and marketing manager at Halliburton. “At shutdown you can find that the amount of sand that you are pumping can be three, four tubings above the pump, and it will fall back to the pump. The result is when you try to restart, the pump is jammed. We developed the SandRight Solids Fallback Preventer—a new product that we introduced six months ago. The SandRight is made up of a number of directional and graduated pathways that stops that sand from flowing in reverse while providing leak-off capability, meaning that the geometry of the passageways on the tool creates a bridge for the sand that’s falling down, stopping it, but also giving you an opportunity to

![Image courtesy of Schlumberger](https://example.com)
leak through it, so if you wanted to do some chemical injections you can still do that through the tool. It is the only tool like this on the market currently with this level of operability.”

Halliburton has successfully deployed SandRight in many of the U.S. unconventional basins. The tool is compact and is easily deployed, according to the company. Its unique sand fallback prevention capabilities address all known issues with most fallback preventers—such as erosion/corrosion, paraffin buildup and jamming issues—while retaining the ability to perform through-tubing chemical treatments.

With the Summit offering, Halliburton is providing erosion protection through a series of coatings that harden stages of the pump to withstand sand erosion. As sand flows through these pumps, it typically erodes all of the mechanical parts in its path.

“We have several coating options available. The DuraHard 7 is a high phosphorous nickel coating that we use to harden the surface and protects against abrasion and corrosion, especially when there is significant presence of heat,” explained Romero. “We also have the DuraHard 15, which is a molecular bond coating and that is for even higher corrosive and abrasive wells in still higher temperatures.”

DuraHard 7 is suitable for application in corrosive environments, recently fracked wells with uniform sand particles, cased-hole operations where sand control isn’t 100% effective and is resistant up to 260°C (500°F). DuraHard 15 can be applied in wells with very high angular abrasive sand and formation fines, wells with quartz sand and in open-hole wellbores or wellbores will no sand control.

When it comes to high temperatures, the problem is mostly when operators are dealing with gas through the ESP system. To assist in combating rising temperatures, a reliable motor is key, according to Halliburton.

“The Corsair motor, which is also a Summit product, can run cooler than any other motor in the market,” said Romero. “The reason why is the design we have in the rotor bearing. It is not inserted and it is thicker. It allows for better heat transfer and less vibration. It has a larger big foot bearing that increases the heat transfer and reduces the internal motor temperature. It also has high-temperature (varnish) and double wrapped insulated windings offering solid protection from temperature rise. Less temperature rise means longer runs and more reliability through the wide production range that you see in the unconventional plays. These are just some of the advancements we’ve seen in the shales.”

Halliburton also has just recently deployed its new DEVIATOR Flange that will allow an ESP system to go deeper and closer to the production zones. One weak point in the ESP is the connections. Halliburton developed reinforcement for those connections. The flange is made of a larger stainless steel cross-section area, has an armored cage-like configuration and a double O-ring connection. The benefits are increased stiffness, preventing permanent deformation, and redundant sealing that prevents leaks. The contractor currently has units working in the Permian.

In the future, Halliburton sees an increased use of permanent magnet motors (PMM), which will increase efficiencies while reducing the overall motor length. Currently, the offset is the cost and drive software compatibility, but the contractor believes in the potential for PMM uses in many markets.

Nearer term, the Halliburton acquisition of Summit is set to spawn a new generation of ESP offerings.

“What you are going to see is a more robust product and a more efficient product—the best of the two,” Romero said. “In the meantime, we are investing in high temperature. We’re going to bring a new product to the SAGD market this year. It is already under
Testing. We’re investing in rigless intervention and new motor offerings for the future as well as digitalization and automation.”

**Making the switch**

For all of the buzz around the digital oil field and advancements in artificial intelligence, the goal for many operators using artificial lift techniques remains unchanged: optimizing when to move from one form of artificial lift to another during the life cycle of a well with the greatest positive effect on production and least negative effect on budget. For some operators, the starting point after a well shows declines is to run an ESP. For others, gas lift is the answer. “Another important aspect of artificial lift is the fundamental question of how to define ‘the best’ technology or strategy for a particular well or field,” says Camilleri. “Of course, it depends on the operator’s economic strategy, the well and reservoir properties, and the capabilities of technology at the time of the decision. Personal preferences often play a role. But even those few variables introduce a wide range of choices. That’s why Schlumberger provides real-time flowrate, IPR and power consumption to help operators make objective decisions about artificial lift technology and strategy.”

The cost equation has raised the profile of gas-lift solutions in the unconventional plays, according to Weatherford. The advantages include low-cost production that leverages the available gas infrastructure. “A year and a half or two years ago, gas lift wasn’t even spoken of in the unconventional space,” Hurst said. “There has really been a shift in focus to gas lift because of cost, but most operators also recognize there are limitations to gas lift. There comes a point in the life of every well where gas lift is no longer efficient due to the decline rate, so operators using gas lift need to have a transition plan to another form of lift after gas lift. One of our solutions is to extend the useful life of gas lift by adding plunger lift to the system along with our advanced automated controls. Plunger lift assist can enhance gas-lift system efficiency and put off the expense of installing rod lift or another form of lift until later in the well life cycle.”

The strategy for moving from one form of artificial lift to another varies from operator to operator, basin to basin and well to well. Some move to artificial lift much sooner in the well’s life than others, which can result in improved cash flow. Typically when a new well starts up, the first few months are driven by its natural flow, but when pressure takes a dive along with the produced volumes, operators must transition to artificial lift. The moment of transitioning from free-flowing to artificial lift, or from one form of lift to another, is when artificial intelligence can have a significant positive impact.

“The first choice varies from operator to operator, but it is usually the high volume methods,” Romero said. “Those are ESPs and gas lift. ESPs are capable of producing high volume, high depths in deviated wells, but gas lift is economical, especially if the operator has the infrastructure in place to supply the gas. That is key. With gas lift, different than ESPs, you can use it with a wide range of production. Imagine these
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When the decline gets high, operators look to change to methods like rod lift. Back in 2014, when oil prices were robust, rod lift was a favored method to follow ESPs. After oil prices collapsed, the economics changed.

“Before it was a matter of getting cash flow from the wells and for that ESPs were the right way to go,” Romero explained. “That is where you get the most production. But with the economics hit, customers started changing to gas lift. With gas lift, you don’t have that cost of intervention like you have with ESPs. You don’t have to use a rig. You use wireline. A lot of operators started using a lot of gas lift. Some that were using rod lift chose not to convert. They would stay with rod lift. Some operators would use plunger or jet pumps. But the most common methods are the ESPs, gas lift and rod lift. There is no recipe. They go from high producer methods to low producer methods. Each operator has its own recipe. I can tell you the king for production is ESP.”

Controller role expands

As wells and the tools that enable companies to produce get smarter, so must other pieces of key hardware and software that integrate into various lift systems. One component that has found itself in an expanding role is the controller. Used typically to control and automate well pad equipment, many now have begun to take on edge computing features allowing for more computational work to take place at the controller.

“A lot of times when we find a bottleneck in the analytics portion of the digital oilfield transformation, it’s because the producer is not getting reliable data on time,” according to Munk with Rockwell Automation. “They can’t rely on the integrity of their data and they are not getting it as they need it.”

One technology Rockwell Automation has released in the past couple of years is a rod pump control optimization package called OptiLift. The company took a different approach when designing this package by using controller technology combined with edge gateway capabilities. OptiLift solutions provide a controller with I/O and communications ready to be used with different artificial lift methods. With a firmware upgrade it can handle gas lift, plunger lift and rod pump controlling the same hardware.

“Over time, this reduces the electrical labor costs and the installation costs that are needed as customers go through these life cycles with their wells,” Munk said.

The controller also gets an upgrade as well pads continue to grow. Over the past decade, well pads in the unconventionals have gone from a single vertical, short lateral well to very long lateral, multiwell pads. Today, 20,000-ft laterals are not so far-fetched, and with eight, 16 or 32 wells to a pad in places like the D-J Basin control systems used for measurements and monitoring need to step up their game.

“These pads are moving from what was once a single-well pad to essentially a small factory,” Munk said. “When you look at it from an automation point of view, you are going from 20 to 50 points of I/O on a single-well pad to upwards of thousands of I/O on a 16- to 32-multiwell pad. Those traditional RTUs start to have problems with CPU horsepower, memory requirements and peer-to-peer communications. We are addressing this with the Rockwell Automation Well Manager solution. It is essentially taking those applications you would normally put in your RTUs to control your wellhead lift solution and integrating all into one single controller that is used with distributed I/O on an an EtherNet/IP network. This solution consolidates the amount of CPU hardware needed on site. It also increases the amount of diagnostic capability on these multiwell pads and provides a centralized configuration so that you can configure your automation control program, your power control for motors and your artificial lift control all from one controller in real time, and hot swap I/O devices so you’re not having to shut the system down when you make changes or expand.”

A simple strategy

The combination of Baker Hughes and GE Oil & Gas into Baker Hughes, a GE company (BHGE) has created a major player in the field of artificial lift. According to Bob Laird, product line director, artificial lift systems for BHGE, the company’s ambition for its artificial lift business is simple—to invent smarter ways to produce oil and gas and exceed the expectations of each customer in the field.

“We have been working with a larger Permian Basin operator, and through close collaboration, we have been able to reduce their production downtime by almost 50%,” Laird said.

“This type of success requires strong engagement with the operator—making sure we design the system that best fits their requirements and optimize equipment operations over time.”
Laird said the BHGE artificial lift group has been able to add value for customers through its four research and development centers. One of the focus areas is modeling, where teams simulate field conditions in the lab to gain a better understanding of performance before applying it in the field. BHGE is also looking closely at how to improve reliability and reduce operating and intervention costs two major drivers for operators.

One of the centerpieces to BHGE’s artificial lift expertise is the electrical submersible pumping (ESP) system facility in Claremore, Okla. Part of a huge investment made in 2014 to advance artificial lift technologies, the campus houses the Artificial Lift Research and Technology Center.

“With eight test wells, we can simulate everything from coiled tubing deployment to critical well testing,” Laird said. “It’s a place where innovation happens every day for our engineers and customers alike. Our research and development capabilities also include various test loops that can test anything from viscosity to abrasives, to gas and temperature thresholds, allowing our team to validate for virtually every type of ESP application. This ensures our technologies are reliable before deploying in the field.”

Laird used the example of a pyramid to illustrate the artificial lift needs of wells around the world. The base of the pyramid represents wells with low intervention costs, while the top layer represents remote, offshore wells that require the highest intervention investments.

“With the industry focusing on the peak of the pyramid, our goal as a service company is to develop alternative deployment systems that help lower these intervention costs—competing with applications at the base of the pyramid and opening up the market,” Laird said. “For example, offshore intervention costs can be as high as $10 to $15 million, but if an operator uses our TransCoil rigless-deployed ESP system, they can cut these costs by a factor of five. So, $10 to $15 million becomes $2 to $3 million, a drastic savings. These are the types of technology innovations we are focused on.”

BHGE’s artificial lift business has been relatively quiet since the merger last July, but Laird said the group is working on new product offerings that leverage the strengths of both legacy companies.

“We’re really going to have some disruptive technologies coming out, not only on the fluid-end or the power-end, but the drive-end ... every component in the system,” Laird said. “Over the next year, we’re excited to start talking to customers and the industry more broadly about some of the disruptive technologies that will hit the market.”

Beyond ESPs, BHGE sees growth potential in something it calls smart gas lift, which GE Oil & Gas had been working on at its Oil & Gas Research Center in Oklahoma City. It is a fully automated system using the digital component along with automation. There also is room to grow in the progressing cavity pumping (PCP) business where BHGE is a strong player. According to Laird, the company believes it can double its PCP business globally over the next couple of years.

Today, BHGE can supply nearly every type of artificial lift operators require—from ESPs to rods and beyond. One place to expect to see more of BHGE in the future is in well cycle management and planning.

“We’re in a unique position to be able to put intelligence in the hands of the customer and make everybody in the industry smarter,” said Laird. “It is a big part of the digitalization of the oil field.”

BHGE is working toward new developments to address high temperature, gas, corrosion and sand applications. When it comes to temperature, the company is working on insulations and new methods of heat evacuation from the well. When it comes to reliability issues caused by sand, Laird explained, the problem isn’t always the amount of sand, but the consistency.

“You can think of sand as having either the consistency of sugar or baking powder,” Laird said. “The sand that is like sugar is big and granular, and the sand that is like baking powder is floury. On an abrasive front, the floury stuff is what really hurts ESPs. You want to protect from that stuff getting into the bearing area, or it will eat away any kind of stability.”

All of these goals fall back to one main point—reliability. It is one thing to understand an artificial lift system, it is another to understand how to mitigate scale and corrosion and other bad things that can happen downhole.

“You can’t solve reliability issues if you don’t know what’s breaking,” Laird said. “We can speculate, and I think the industry in general does a lot of speculation. We want to get it down to where we are making data-driven decisions, and digital will help us do that. If I’m the chairman of an oil company and I can see what it is costing me per well in real time to operate I can start making some pretty smart decisions about how to change what is going on with my production from that rock. I can do it from the type equipment that I’m running, I can do it from how I manage the reservoir. If you can put that intelligence at the edge then I think you really have a winner.”
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PMM eliminates induction losses

Operators are looking for new ways to increase electric submersible pump (ESP) system efficiency and lower lifting costs, especially in declining, mature fields. The new Magnefficient permanent magnet motor (PMM) significantly improves efficiency by lowering ESP system energy consumption, allowing operators to do more with less. The Magnefficient PMM eliminates induction losses, lowering system power consumption by 20% and reducing motor power loss by 50%. It also delivers a higher power density, enabling operators to eliminate the need for tandem motor connections, which improves reliability and allows for quicker installation, saving additional time and cost. Baker Hughes, a GE company, leveraged learnings from other GE businesses to develop the Magnefficient PMM, including GE Aviation for the rotor design and GE Healthcare for magnet research. The R&D team used advanced optimization algorithms to make sure the efficiency design elements did not violate temperature limits, rotor dynamics stability or material structural capabilities.

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Modular-designed plunger lubricator reduces costs

Definitive Optimization’s Dual Valve assembly “Inclusive Modular” design has saved thousands of dollars for its customers because the design removes the need for significant line modification to install a typical plunger lift lubricator. The design focuses on reducing the extensive cost of facility modification to accommodate the installation of a plunger lift lubricator while ensuring functional and efficient...
operation of the plunger lift equipment. The design also enables installation that can be accomplished in under one hour. The assembly can be reconfigured to fit in the spacing where the existing API flow tee and wing valve or API flow block and wing valve are located with a few easy adjustments. This design also eliminates expensive highline modifications as well as reduces field and engineering costs and extended downtime. This flexibility minimizes location flowline modifications and the extra costs that typically come with the modifications. The design is fully engineered, 100% inspected and 100% tested. Fire safe valves, steel-on-steel primary connection seals, and 3,000-psi and 5,000-psi w.p designs are available.

Using kinetic energy for plunger lift safety and maintenance

The Sasquatch plunger velocity sensor is a new innovation that measures surface velocity of the plunger just before it strikes the anvil inside the lubricator. Sasquatch uses the surface velocity and mass of the plunger to calculate the kinetic energy of each plunger arrival in real time. This is compared to user-defined thresholds for hard and dangerous hits, resulting in alarms that can be used to shut down operation of the plunger well to protect equipment. Kinetic energy of hard and dangerous hits is summed over time to predict spring wear. These features allow operators to make use of kinetic energy ratings that are stamped on lubricators as part of the new American Petroleum Institute 11 PL standard.

Injection pressure operated gas-lift valve

Flowco Production Solutions has developed a line of high-pressure (HP) gas-lift equipment that solves the issue of equipment failure at higher reservoir pressures. As operators encounter higher reservoir pressures or decide to employ higher discharge compression to lift deeper and maximize production, the pressure ratings of common gas-lift equipment can be exceeded and lead to failure. The TPH-1.0 achieves valve test rack opening pressures of 3,000-plus psi and is designed to withstand external pressures of up to 10,000 psi. To further resolve these issues in conventional or gas-lift applications, the TPH-1.0 system, when coupled with Flowco’s 10K HP Check Valve and Tubing Retrievable 10K HP Mandrel, meets the challenges of today’s HP land applications. The HP line also is available in wireline retrievable models.
Tool deters fallback debris from entering ESPs

In May Halliburton introduced the SandRight solids fallback preventer, a technology to mitigate problems from fallback debris entering electric submersible pumps (ESPs) during artificial lift operations. SandRight addresses an issue that occurs during power shutdown events, where solids hovering in production tubing above an ESP can fall into the pump, causing major problems as they become lodged in the pump’s stages. Attempts to restart the pump can overstress motors, accelerate wear on the pump, overheat cables or even result in catastrophic failure. SandRight maintains the ability to execute thru-tubing chemical treatments and is protected from jamming, erosion and paraffin/scale buildup.

The tool protects ESPs from permanent damage, while significantly increasing an ESP’s run time in unconventional applications. For unconventional assets, the SandRight tool is estimated to save an annual $250,000 to $800,000 per well in operational efficiency and lost production.

Optimizing artificial lift with multiphase pumps

As wells mature, the inflow from surrounding formations will lead to lower level in the production tubing limiting uptime of traditional pumpjacks. The lower tubing level will add more solution gas. The annulus or casing gas is traditionally bled off and comingled with the liquid stream of the pumpjack. Operated in pump-off control mode, the low tubing level will stop the pumpjack, the gas flow stalls and the well shuts in. The multiphase pump, which is designed for the gas saturated with liquid is offering an alternative to traditional casing gas compressors. The compressor cannot accept any liquids and relies on a combination of scrubbers and blow case for protection. It often leads to cycling and shutdowns from too much liquid. In the Leistritz multiphase annulus gas unit (MAGU) system, both the annulus gas and liquid streams are routed through the unit. The lower annulus gas pressure will raise the tubing level, allowing the pumpjack to operate safely as result of better well inflow. With the MAGU combined with pump-off control, the result is improved uptime and less rod wear leading to better economics.

New artificial lift ESPs

Novomet has introduced a new ImpalaESP product line with an extended operating range. The ImpalaESP compensates for axial force and maintains the impeller in the float state. This achieves low axial force values in a wide range of flow rates for a wider operational range.

Working in horizontal wells, Novomet’s gas prevention intake eliminates the problem of undissolved gas. The intake design contains a rotating cylinder, which sets the input port down. This allows the gas to rise and shutdowns from too much liquid. In the Leistritz multiphase annulus gas unit (MAGU) system, both the annulus gas and liquid streams are routed through the unit. The lower annulus gas pressure will raise the tubing level, allowing the pumpjack to operate safely as result of better well inflow. With the MAGU combined with pump-off control, the result is improved uptime and less rod wear leading to better economics.

MAGUs are typically mounted on a drag skid and can be moved easily from one well to another or left in place to support one well. (Image courtesy of Leistritz)

ColibriESP allows the well to be completed without the rig crew. (Photo courtesy of Novomet)
above the port, preventing gas intrusion. In addition, Novomet’s ColibriESP provides thru-tubing production with a cable-deployed electric submersible pump (ESP) system. This allows the well to be completed without the rig crew. Novomet also has introduced the ESPCP, a progressing cavity pump (PCP) with a submersible permanent magnet motor. The ESPCP performs in marginal wells (20 bbl/d to 125 bbl/d) where typical ESPs are not applicable or where the well operates periodically. The ESPCP also is designed for wells with flow rates from 125 bbl/d to 1,000 bbl/d, wells with high fluid viscosity and emulsions (600 to 1000 cSt) and wells with paraffin-based fluids. The ESPCP also is a good candidate for gas wells with up to 50% at intake as well as deviated wells.

Platform offers rich data visualization from multiple wells or zones
Sercel-GRC’s artificial lift gauge systems provide subsurface data needed to optimize electric submersible pump, gas-lift, progressing cavity pump, rod pump and jet pump applications. GRC’s gauges measure pressure, temperature, vibration and other downhole conditions. The universal artificial lift instrumentation system working with the company’s industry partners in the areas of fiber optics, hybrid cable applications and predictive analytics provides bottomhole and wellbore characterization on each well. The GRC open-source Data Pro platform provides one common visualization solution for all GRC universal gauges providing a true life-of-well optimization platform. Gauges can be installed thru-tubing, above a pump or below a pump. These installation options have been standardized, allowing one gauge to be redeployed through multiple artificial lift completion methods.

Automated chemical injection based on artificial lift control technology
The latest development on the Smart Pumper is that it can remotely control and monitor chemical injection pump operations while it controls and monitors artificial lift systems. The method used to automate chemical pumps is tied to Smart Pumper’s precision pump speed control based upon real-time fluid level to the specific level users wish to achieve and maintain over time.

As Smart Pumper automatically changes the speed of an artificial lift device or surface injectors, it automatically changes the speed of a series of chemical pumps to keep chemistry perfectly aligned with automated output, which helps in keeping the chemical cost low. Smart Pumper is proven to increase production 18% to 57% and reduce lift costs.
Increase ESP runlife in high solid content wells

Producing significant volumes of abrasive sand, iron sulfate and other solids with electric submersible pumps (ESPs) presents challenges, which can compromise system runlife. In standard constructions, excessive abrasives can wear pumps quickly, reduce performance and cause premature failures. To provide advanced wear protection without sacrificing pump efficiency, Valiant Artificial Lift Solutions offers abrasion-resistant modular (ARM) pumps featuring robust tungsten carbide bearings for enhanced radial support. Since pump down thrust is carried at each ARM bearing placement, no impeller or diffuser down-thrust load is transferred to the ESP’s seal section, thus raising the total thrust load capacity of the ESP and allowing deeper setting depths. Additionally, Valiant’s ARM bearing sets feature a system of slots and grooves with unique geometry, proven in the field to allow sufficient flow of solids through and around the sleeve and bushing, thus preventing accelerated wear, heat buildup and shaft breakage associated with sand accumulation in these spaces. valiant-als.com

The slot and groove geometry on this bearing set allows ESP systems to operate efficiently in high solids production. (Image courtesy of Valiant Artificial Lift Solutions)

Unit boosts productivity with a longer stroke

The latest Weatherford Rotaflex long-stroke pumping unit helps operators transition to high-performance rod lift and eliminate the need for intermediate lift methods. The Rotaflex unit boosts productivity with a longer stroke, more complete barrel fillage and less wear on surface and downhole equipment. Even in deep, high-angle or high-gas-to-liquids wells, the latest Rotaflex unit was redesigned to further increase uptime, reduce the total cost of ownership and streamline maintenance. With stroke lengths up to 366 in., the unit increases system efficiency and energy savings, substantially lengthens sucker-rod and downhole-pump longevity, and reduces cycles, reversals and the risk of downhole failure. The design simplifies inspections and repairs, encloses moving parts and offers easy access to major components. weatherford.com

Autonomous rod pumping issue detection, resolution

Zedi’s SilverJack Artificial Lift solution provides advanced rod pumping technology to the upstream oil and gas industry. The SilverJack portfolio consists of several product configurations spanning a wide range of oil and gas wells from low to very high producers. Features such as remote access, flexible alarming, precise rodstring control and advanced optimization capabilities have helped producers lower their costs while realizing their production potential. With the introduction of a new algorithm, the SilverJack artificial lift system can autonomously detect and resolve common downhole rod pumping issues such as a stuck standing or traveling valve and gas lock. The unique algorithm uses operating parameters, such as the dynamometer card, to detect and identify issues then autonomously make adjustments to the stroke profile in an attempt to resolve the issue. By addressing issues in near real time, this new capability has the potential to significantly enhance a well’s production. zedisolutions.com

Rotaflex unit was redesigned to increase uptime. (Photo courtesy of Weatherford)
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Improving ESP Installs by Removing the Rig

Coiled tubing-deployed ESP system allows for faster and safer installations in wells both onshore and off.

By Lara Zsohar and Yahya Sarawaq
Baker Hughes, a GE company

In new field developments and mature assets alike, electrical submersible pumping (ESP) systems are an effective artificial lift method for boosting production rates and extending the economic life of mature wells.

But for many operators, conventional rig-deployed ESPs do not always deliver on their promised potential. A limited inventory of rigs to install ESP systems, coupled with prohibitive intervention costs, unreliable electrical connectivity in the well and the increased safety hazards that work crews may face during rig-based deployment, have limited the wider use of ESPs, especially in remote and offshore applications.

The first TransCoil system was installed in December 2016 in a well in the Middle East. The well was brought back into production after one year of downtime, producing at a rate of 8,000 bbl/d. The planned rig schedule was not interrupted, and workover costs for the project were approximately one-half of what they would have been using a rig. (Photo courtesy of Baker Hughes, a GE company)
Baker Hughes, a GE company (BHGE) developed its TransCoil rigless-deployed ESP system to improve installation while removing rig-related challenges. Designed in collaboration with a national oil company, TransCoil takes the rig out of the installation equation, with an aim of helping operators to bring wells on production faster while lowering overall lifting costs.

The system includes an inverted ESP with the motor above the pump and connected to the high-strength, corrosion-resistant power cable. The system is installed through the existing completion via coiled tubing (CT).

This design improves ESP installation and operational life in several ways. Placing the motor on top eliminates the motor lead extension, which is the area with the highest potential for electrical failure in conventional ESP systems. The new configuration prevents migration of water through the seal to the motor, increasing reliability and extending runlife.

The power cable is encapsulated in the CT string, which protects the cable during installation and helps ensure long service life in extreme production environments. Fully isolating the cable from well fluids also eliminates cable elastomer expansion during changes in pressure cycles.

**Resolving common problems**

By removing the need for a rig to install and retrieve ESP systems, the TransCoil system eliminates the lost time and deferred production associated with waiting for a rig. The system can be deployed and retrieved under live well conditions, which means that the tubing and completion assemblies do not have to be retrieved to install a new ESP. In addition, the time involved in killing the well and the associated risks are eliminated, and the potential costs of dealing with wet-connect failures are avoided. Taken together, these improvements help cut ESP installation times by 50% compared to a conventional rig-deployed system.

Unlike wireline-deployed ESPs, the new system can be installed through a deviation in the wellbore. This capability allows operators to land the ESP closer to the producing zone for greater reservoir pressure drawdown and reserves recovery. The ESP can be reliably installed later in the life of the well, thus eliminating the need to install the system when a well is first drilled when it could then sit idle for months or years.

The new system is designed to eliminate most common failure points. For example, approximately 30% of all ESP failures are due to electrical components, and of these, 46% are associated with the motor lead extension or cable. But by connecting the motor directly to the power cable, the TransCoil system eliminates the failure-prone, in-well “wet connection” for improved system reliability.

And rather than relying on typically available CT sizes and metallurgies, the power cable can be fabricated from metallurgies that are specifically geared for well requirements. Premium metallurgy options can withstand H2S saturation levels as high as 15% to significantly extend ESP operational life in harsh-environment fields.

With an outer diameter that is approximately 40% smaller than current 2½-in. CT cables, the new cable is significantly lighter and reduces tubing pressures. The cable design also extends the ESP operating range to 12,000 ft and beyond, depending on operational loads, exceeding capabilities of other CT-deployed ESP systems.

The fully retrievable ESP system is different from other CT solutions in that it can be re-used for multiple workovers. Bending fatigue testing demonstrates that the system withstands up to 180 trips in and out of the well. The system can be installed in 4½-in. to 9-in. casing in wells with flow rates up to 20,000 bbl/d. In mature offshore fields, where high intervention costs can limit the application of ESPs, the system can be deployed through the existing 4½-in. tubing.

**Dealing with unplanned workovers**

With rig schedules typically established a year in advance, entering an unplanned ESP workover into the rig plan is a logistical challenge. This can lead to long lead times to get a rig on location to retrieve and install ESP systems, resulting in downtimes of three to six months or longer. But because of its ease and speed of deployment in a growing number of field trials, the new rigless-deployed unit allows operators to get production back online quickly at increased rates.

The first TransCoil system was installed in December 2016 in a well in the Middle East that had been waiting a year for a rig to replace an ESP system that experienced an electrical failure. Rig-based work to replace the completion and install a vertical electrical penetrator system was completed ahead of the rigless operations. A BHGE CT team helped plan the operation, delivered a surface unit to the well site and worked with artificial lift engineers to install the system.

The well was brought back into production after one year of downtime, producing at a rate of 8,000 bbl/d. The planned rig schedule was not interrupted,
and workover costs for the project were approximately one-half of what they would have been using a rig. The rigless-deployed ESP system also reduced overall installation time by 50% compared to a rig-deployed system.

A second system was deployed for the operator of a mature field offshore Malaysia that was looking for an economic intervention solution to stabilize production and manage increasing water production. The well had been shut in for 18 months due to inadequate reservoir pressure to achieve natural flow with an increasing water cut and reduced gas rates. In this first offshore installation, the system reduced workover costs by more than 50% compared to a rig-based intervention. The system boosted oil production by 127 bbl/d after more than a year of being offline, generating thousands of dollars of additional daily revenue in the process.

The third system was installed in a reservoir with high H₂S content. Two ESPs previously installed in the same well had both failed prematurely due to electrical failure. A workover rig pulled the failed ESPs in August 2017 and ran the necessary completion for the rigless ESP deployment. The new install operation was completed in December 2017 in half the time it took to install the first system. The well now produces at a rate of 8,000 bbl/d.

In these field trials and others, the rigless-deployed ESP system consistently saved time and money on lift system installations while dramatically increasing reliability at reduced HSE risk. Other operators are looking to deploy the new ESP system to recover oil in wells that they might have otherwise abandoned due to high intervention costs.
The majority of the world’s gas-lifted wells are routinely operating in a non-optimal state.

Addressing this with existing technology is typically time-consuming, costly and risky, requiring frequent well interventions with associated production loss. Additionally, it is not currently possible to fully automate the day-to-day operation of a gas-lifted well. A data-driven approach to on-demand in-well adjustment of lift gas depth and rate to assure maximum and stable production is not possible.

Despite being extremely compliant, gas lift currently presents some challenges. These include uncertainties around the effective monitoring and measurement of gas-lift efficiency, and intervention for valve deployment to optimize production. The combined effect of a lack of data and the need for costly intervention create production limitations.

Eliminate uncertainties

For production engineers operating gas-lifted wells the day-to-day challenges are how to produce more efficiency with less intervention and how to obtain more data to enable decisions with less uncertainty. These challenges typically revolve around answering questions that are rarely easy to answer. These include if the well is completely unloaded or if it is multipoint injecting, the lift depth, whether the well is optimized on gas lift, if the well could be lifted at a greater depth and if the wellbore hydraulic model is a good match for the actual well performance. Other important questions center on the extent and timing of required intervention, allocating available lift gas and the details of the lifting life cycle.

Because of the limited functionality and flexibility of legacy completion hardware, answering these questions and making adjustments to optimize gas-lifted wells has until now involved a considerable amount of costly well intervention, nonproductive time and associated risk. This can include the need to gather surface data, planning and running a production log and analyzing that data, deciding which valves to change out, executing an intervention, changing out the appropriate valves if possible and bringing the well back on test. This whole process can take weeks or even months of work and is rarely accomplished to the degree necessary to assure continuously optimized gas-lift production.

Technological limitations have meant that a lack of understanding and insight into the exact conditions downhole and the time it can take to remedy or adapt to them has tended to generate a high degree of uncertainty in the gas-lift process. It has also created a culture of costly over conservatism, particularly when it comes to such issues as deciding on the number and spacing of valves required for unloading and effective lift.

However, the recent rise in the adoption of digitalization in the oil field, with the creation of intelligent fields and wells, have enabled significant advances and created a paradigm shift in the way gas-lifted wells can now be operated to achieve optimum production.

More production, less intervention

The new Digital Intelligent Artificial Lift (DIAL) gas-lift production optimization system developed by Silverwell Energy is leading that cultural and process change in artificial lift. The DIAL system...
ARTIFICIAL LIFT: CASE STUDIES

encompasses a fully qualified, tubing conveyed surface-controlled multi-rate gas-lift unit, rated to 10,000 psi burst, 6,000 psi collapse and 257 F. Each unit includes up to six independently actuated orifice valves and onboard pressure and temperature transducers.

The system allows more production from enhanced lift efficiency to accelerate return on investment, less intervention with a reduction in opex and risk, more data through the increased insight afforded by multiple in-well sensors, and less uncertainty with the potential for improved production management decisions due to the deployment of an integrated gas-lift optimization system.

DIAL integrates downhole and surface monitoring/controls in real time. The different sized orifice valves housed in the in-well DIAL units accommodate a wide range of unloading and gas-lift production operating conditions. As reservoir conditions change, the injection rate and depth can be remotely adjusted from the surface and confirmed in real-time data.

The system’s design does not incorporate gas bellows, meaning there is no requirement for a gas charge with no dependence on pressure or temperature. It, therefore, overcomes the well design and operational limitations of existing side pocket mandrels and gas-lift valves, which are installed with pre-configured orifice sizes and require potentially risky well intervention to make adjustments as conditions change throughout field life.

The DIAL gas-lift valves are not pressure dependent, making them less sensitive to uncertainties in well design variables. There is no requirement to design, at each unloading valve, a pressure differential to avoid multipointing and valve chatter, enabling the deepest possible injection point to be determined. The system is less prone to flow instability. Furthermore, the injection orifice size can be adjusted without intervention and onboard pressure, temperature and condition monitoring are achieved at all injection points in the completion string.

A surface control unit powers and transmits data to and from the DIAL units via industry standard ¼-in. clamped tubing encapsulated cable and can be configured to support multiple units in a single well. The downhole control system is hermetically sealed with electron beam welds to assure life-of-well system reliability, while the gas-lift orifice valve assemblies are contained in a 10,000 psi burst rated housing.

The operation of the DIAL unit is enabled by Silverwell’s Binary Actuation Technology (BAT), which consumes no power until a low energy control signal is applied. This attribute of the BAT technology platform is instrumental in assuring the 10-year to 20-year design life of the in-well components of the system.

Overall, through its benefits over legacy gas-lift technologies that have a relatively narrow operating window, often excessive safety design margins that can limit achievable injection depths, multiple potential leak paths and challenges in assessing lift effectiveness, the DIAL system represents a significant reduction in the total cost of gas-lift operations.

More data, less uncertainty

DIAL has been deployed successfully in the Middle East and Southeast Asia beginning in 2017. In all cases, within days and weeks of installation, the system was being used to optimize lift efficiency without the cost and deferred production of intervention.

In one case, without the need for intervention and by using downhole gauge measurements provided...
by DIAL units, the operator was able to instantly recognize the opportunity to increase the well’s gas injection rate giving a 10% production rate increase. In another instance, a simple adjustment of the DIAL system mitigated a well instability issue by overcoming multipoint injection. In an additional example, again through using downhole gauge measurement rather than intervention, the operator recognized the opportunity to reduce the gas injection rate in a well. The valve combination was changed, leading to an increase in casing pressure and an increase in net oil production by 18%.

The system is currently being deployed offshore as the next stage in a technology roadmap that culminates in subsea installations. In subsea, the production optimization and opex reduction DIAL enables even more material, to the point of potentially positively impacting field development economic viability by enabling gas-lifted operation without intervention for the life of the field.

The ability afforded by digitalization to eliminate production uncertainty, instabilities and operational costs by providing continuous, intervention-free gas-lifted well optimization is generating significant cost and time benefits for operators aiming to optimize production, increase financial returns and reduce risk. Business cases developed in collaboration with gas-lift users in multiple onshore and offshore operating environments attest to this. A production optimization adjustment that would have required multiple interventions over weeks or months previously can now be completed in minutes. Aligning these benefits with the ease of installation and operation makes the DIAL system a valuable contributor in the drive toward the digital oil field.
Advances in real-time data transmission have been a game-changer for improving the effectiveness and runlife of artificial lift systems. However, sophisticated gauges and sensors capable of delivering large volumes of information are just part of the solution. To meet the economic and technical challenges of today's wells, operators require a more comprehensive approach that transforms data into action through round-the-clock remote system surveillance, quick identification of necessary remedial action before problems occur and post-job investigation to analyze equipment failures and correct issues going forward.

What traditionally involved a reactive process, with data from failed electric submersible pumps (ESPs) analyzed by multiple systems in a time-consuming and inefficient manner, has evolved into a proactive streamlined workflow that quickly identifies events and recommends appropriate action while managing pump operations for the entire well production life cycle.

From a single digital platform, the Schlumberger Lift IQ production life-cycle management service provides an integrated, solutions-based surveillance approach that securely collects, transmits, evaluates and interprets real-time data to optimize artificial lift performance. Data transmitted from the well site by satellite or cellular connections are monitored by a dedicated team of engineers at six remote 24/7 Artificial Lift Service Centers (ALSCs) strategically located in Europe, the Middle East, North America, South America, Russia and Asia.

Using tools embedded in the system, experts simultaneously monitor data from multiple wells across fields, analyzing hundreds of alarm triggers to capture, mitigate or prevent adverse pump events. They identify causes, such as scale buildup, and take the necessary corrective actions to extend pump life, avoid workovers and prevent shutdowns. Experts can use the data to correct specific problems, update pump regimens to accommodate fluctuating conditions or identify underperforming wells that could see improvement with pump optimization.

The ALSC processes alarms and events and uses diagnostic tools to communicate real issues to field operators to take immediate action to save ESPs from potential damage or failure. Each event is classified and assigned a level of severity to easily prioritize critical intervention, assign appropriate actions and compile them in a database to perform further event analysis.

The surveillance workflow features a “fast loop” for responding to alarms and taking immediate action after analyzing the data and a “slow loop,” for conducting root-cause analysis and long-term remedial action and improving pump runlife by identifying recurring events and implementing operational procedures and design change.

Additionally, ALSC production engineers work closely with Schlumberger’s dismantle, inspection and failure analysis (DIFA) teams, which provide post-job analysis and inspection to determine specific causes of equipment failures and recommend further corrective actions.

Early response to scale buildup

Scale buildup on ESPs is a common occurrence leading to a host of problems that impact the efficiency of the system over time, often with no outward or immediate indications. In cases of

By Jose Leon Araujo
Schlumberger
 unchecked scale buildup, high pressure or motor overheating can cause the ESP controller to shut down the well to protect the system.

In a scale-prone field in the Egyptian West Desert, Khalda Petroleum Co. used the production life-cycle management service to detect early scale buildup on an ESP in one of its artificially lifted wells and recommended immediate action to remedy the situation. When engineers at the Middle East ALSC recognized a rise in intake pressure and motor temperature as an early sign of the scale buildup, they recommended decreasing the motor loading to prevent the well from tripping. This action enabled the onsite Schlumberger team of field engineers to clear the scale by safely injecting acid washes through coiled tubing directly on the discharge head of the pump. Without the acid treatment, the motor likely would have continued to overheat, resulting in reduced runlife or catastrophic failure (Figure 1).

Early detection of the scale buildup and quick response to address the problem prevented unnecessary delays and saved Khalda Petroleum $540,000 in workover costs and deferred production.

Eliminating costly workovers

In a North Sea field, scale buildup resulted in slow production in affected wells, forcing the operator to perform scale squeeze treatments by pumping an inhibitor downhole to prevent scale deposition. Over a period of several years, the operator performed 630 scale squeezes on 50 wells in the field, 10 of which experienced ESP failures within one month of the treatment. Each failure required a $2 million workover.

Upon investigating the problem from a center in the U.K., the DIFA team determined that 10 ESPs have experienced electrical failures immediately following the scale squeeze treatments. The failures were triggered by the fluid treatment ingress past

![Figure 1](image.png)

**Figure 1.** The Khalda Petroleum Co. well experienced partial plugging due to scale deposition. The issue was identified, and an acid wash was performed. However, the Lift IQ service showed that motor temperature continued to rise after the acid wash, so the ESP speed was remotely reduced to lower the temperature. (Image courtesy of Schlumberger)
the elastomers, which were not rated for temperatures below 50 C (122 F), and subsequent damage to the O-ring seals. In a move to eliminate the problem, the operator selected the production life-cycle management service to help maintain an acceptable downhole temperature while performing the scale squeezes to avoid leakage past the seals.

Using information from the DIFA team, production engineers at the U.K. ALSC implemented a proactive surveillance plan to remotely monitor downhole temperature data from gauges on the ESPs and surveil wells during all scale squeeze operations. If the well temperature dropped below 70 C (158 F), the ALSC engineers advised field engineers at the offshore well site to reduce the inject rate of the scale squeeze by 15%. If the well temperature reached 122 F, the lowest threshold of the elastomers, the ALSC engineers would notify the field engineers to pause the operation until the temperature stabilized to maintain the integrity of the seals and prevent an ESP failure (Figure 2).

Since the operator began using the production life-cycle management service, a total of 157 scale squeeze treatments have been performed on 54 wells with no subsequent ESP failures. Through collaboration with the DIFA team to determine the cause of the failures, and ongoing cooperation between the ALSC and well services field engineers to continuously monitor well temperature and adjust pumping protocols, no well has dropped below the minimum acceptable temperature and the operator has saved millions of dollars in workover costs.

Since the production life-cycle management service was launched in March 2017, it has been implemented by more than 200 companies in more than 30 countries where it has improved run times, reduced costs and improved productivity by monitoring single wells to optimizing operations across entire fields. Operators can customize the service, choosing from four service tiers, all with ALSC access. The first level includes visualization and system protection while the second provides proactive ESP management. The third and fourth tiers identify potential wells and fields for production optimization. In addition to long-term monitoring and analysis, the service monitors the important commissioning phase of an artificial lift system.
When you’re in charge of a well’s production, every decision counts. For example, when you spec ToughMet 3 Sucker Rod Couplings, you’re choosing the coupling that tripled average run times and increased fluid production by 10-15% in field tests. ToughMet alloy is a high-strength, nonmagnetic copper-nickel-tin material that provides exceptional galling and corrosion resistance, which translates into fewer workovers, greater production and, ultimately, less pressure on you.

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