

Artificial Lift for High-Volume Production

Rod pumps bring oil to surface in many fields, but for better flow rates more than 100,000 wells use subsurface electric pumps or inject external gas to lighten the fluid column. Specialized approaches are needed to optimize existing gas-lift or submersible systems and to design new installations for more complex applications.

Roy Fleshman

Bartlesville, Oklahoma, USA

Harryson

Obren Lekic

Houston, Texas, USA

Less than a fourth of producing oil wells flow naturally. When a reservoir lacks sufficient energy for oil, gas and water to flow from wells at desired rates, supplemental production methods can help. Gas and water injection for pressure support or secondary recovery maintain well productivity, but artificial lift is needed when reservoir drives do not sustain acceptable rates or cause fluids to flow at all in some cases. Lift processes transfer energy downhole or decrease fluid density in wellbores to reduce the hydrostatic load on formations, so that available reservoir energy causes inflow, and commercial hydrocarbon volumes can be boosted or displaced to surface. Artificial lift also improves recovery by reducing the bottomhole pressure at which wells become uneconomic and are abandoned.

Because reservoir pressure declines and more water is produced late in field life, artificial lift is generally associated with mature oil and gas developments. However, driven by activity in deep water and areas that require construction of complex wells, the mature state of hydrocarbon exploitation worldwide has increased demand for high lifting rates to produce oil quickly and efficiently at low cost. Offshore and in difficult international regions, artificial-lift techniques accelerate cash flow, generate profits sooner and help operators realize better returns, even in wells that flow naturally.

Rod pump, gas lift and electric submersible pumps are the most common artificial-lift systems, but hydraulic and progressing cavity pumps are also used. Each is suited to certain lifting requirements and operational objectives,

but there is overlap between systems depending on subsurface conditions, fluid types, required rates, well inclination angles, depths, completion configurations, lift-system hardware and surface facilities.

Lift optimization to get the most fluid from a well or field at the lowest cost offers opportunities for substantial production gains in new wells or mature fields. When selecting and designing lift systems, engineers must consider reservoir and well parameters, but field development strategies should be factored in as well. Artificial-lift selection is specialized and often tedious, but guidelines provide the relative applicability of each method ([previous page](#)).¹

Artificial-lift technology is well established, but new developments continue to play a role in solving problems and meeting production challenges. Recent improvements reduce lifting costs through system components that resist hostile environments, optimize power usage and improve reliability. Alternative means of deploying lift systems allow profitable production from previously uneconomic wells or fields. Traditional artificial-lift limits are expanded by using more than one lift method in the same well, such as gas lift or jet pumps combined with electric submersible pumps and progressing cavity pumps driven by electric submersible motors. This article reviews basic lift systems, discusses high-volume artificial lift and presents selection, design and optimization strategies along with new gas-lift and submersible technology.

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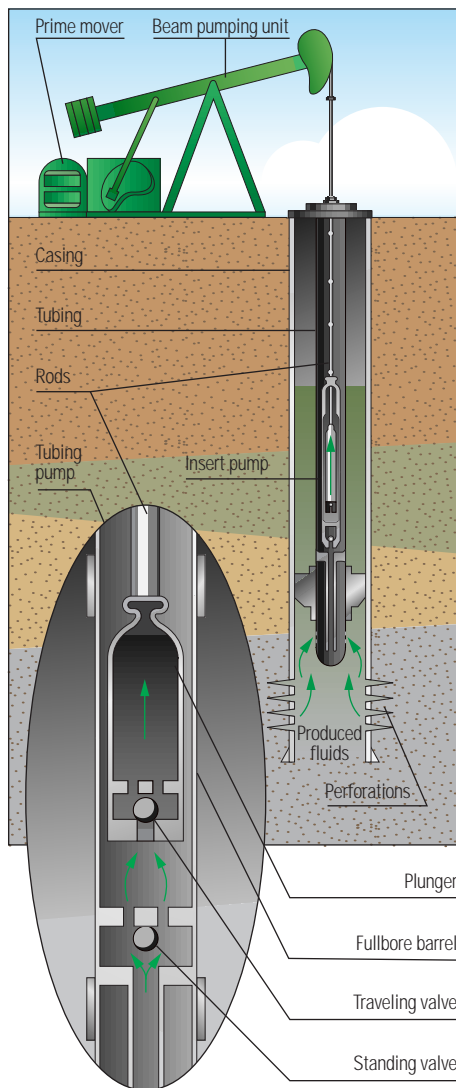
1. Brown KE: *The Technology of Artificial Lift Methods*, vol. 2A. Tulsa, Oklahoma, USA: PennWell Books, Inc., 1980.

< Artificial-lift selection. Making artificial-lift decisions is primarily a process of choosing the lift methods most applicable to expected surface, reservoir, production, fluid and operational conditions. This table provides applicability values and selection criteria or conditions for the basic forms of artificial lift. To choose a method that meets production requirements, select the range that applies—good to excellent (1), fair to good (2) and not recommended or poor (3)—for key criteria, tally these values and weigh the results.

Basic System Descriptions

The four basic subsurface artificial-lift groups include rod or progressing cavity displacement pumps; jet, piston, turbine or plunger hydraulic pumps; gas lift; and electric submersible centrifugal pumps.²

Rod pumps combine a cylinder (barrel) and piston (plunger) with valves to transfer well fluids into the tubing and displace them to surface. These pumps are connected to surface by a metal rod string inside the tubing and operated by reciprocating surface beam units, or pumping jacks, that are powered by a prime mover—electric or gas motors—(below). There are two types of linear-displacement rod pumps. Tubing pumps have a fullbore barrel with standing valve and are attached to the end of the tubing. A plunger, or traveling valve, is run into this barrel on the rods. Tubing must be pulled to repair or replace tubing pumps. Smaller insert pumps consist of a barrel, intake valve, plunger and discharge valve com-



bined in an integral assembly run inside tubing on rods. Insert pumps can be retrieved and repaired or replaced without disturbing the production tubing by just pulling the rods.

Fluids are pulled into pump barrels by close-fitting plungers with check valves to displace fluid into the tubing. Standing, or intake, valves consist of a stationary ball-and-seat. The discharge, or traveling valve, moves during each reciprocating pump cycle. Rod pumps are simple, familiar to most operators and used widely. However, rod pump capacity, or volumetric efficiency, is limited in wells with high gas/liquid ratios, small tubing diameters or deep producing intervals. Other disadvantages are a large surface footprint (space requirement), high capital investment and potential wellhead leaks or spills.

Progressing cavity pumps are based on rotary fluid displacement. This spiral system consists of a rotor turning eccentrically inside a stationary stator (next page, top left). The rotor is a small-diameter screw with deep round threads and extremely long pitch—distance between thread peaks. The stator has one more thread and longer pitch than the rotor, which forms cavities that progress in a rotating motion to create almost pulsation-free linear flow. Like rod pumps, the rotor is generally turned by rods connected to a surface motor. New rodless installations use subsurface electric motors and a speed-reducing gearbox to turn the rotor.

In most cases, progressing cavity pumps are flexible, reliable, resistant to abrasive solids and volumetrically efficient. Use of small motors results in efficient power usage and low lifting costs. Compared to rod pumps, progressing cavity pumps last longer and have fewer rod or tubing failures because of slower operating speeds. Capital costs are typically less than other artificial-lift methods. Progressing cavity pumps produce up to 1700 B/D [270 m³/d] and are used to depths of about 4000 ft [1220 m]. Elastomer components limit operating temperatures to between 212 and 302°F [100 and 150°C] and may not be compatible with some chemicals or hydrogen sulfide.

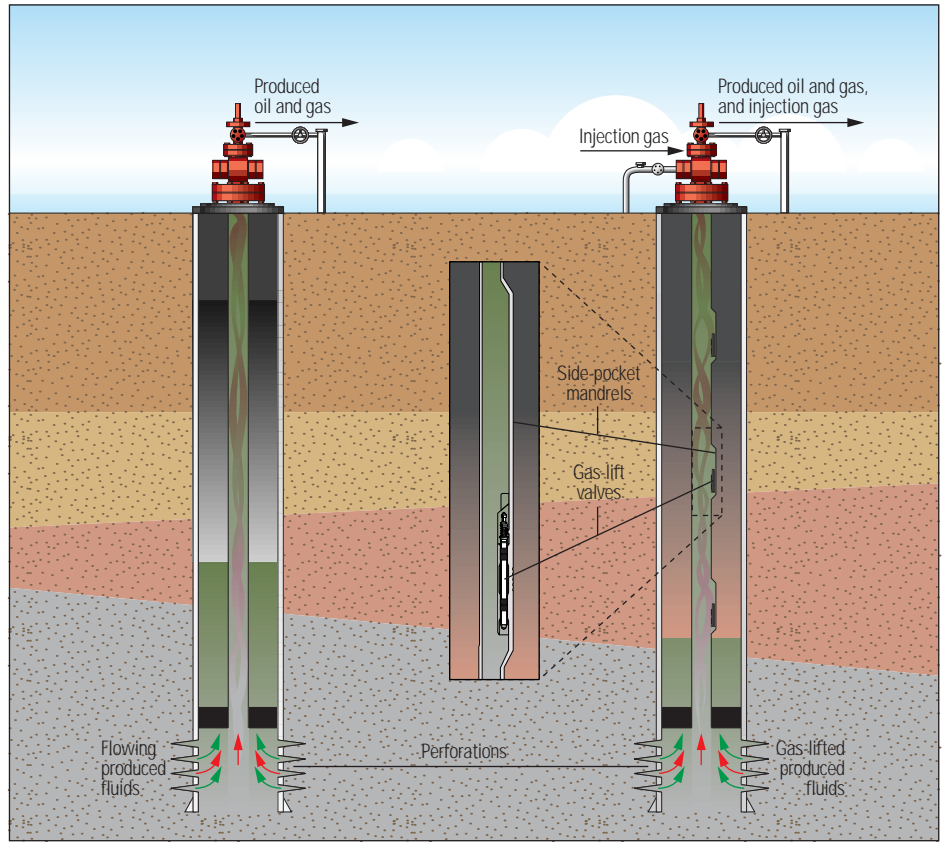
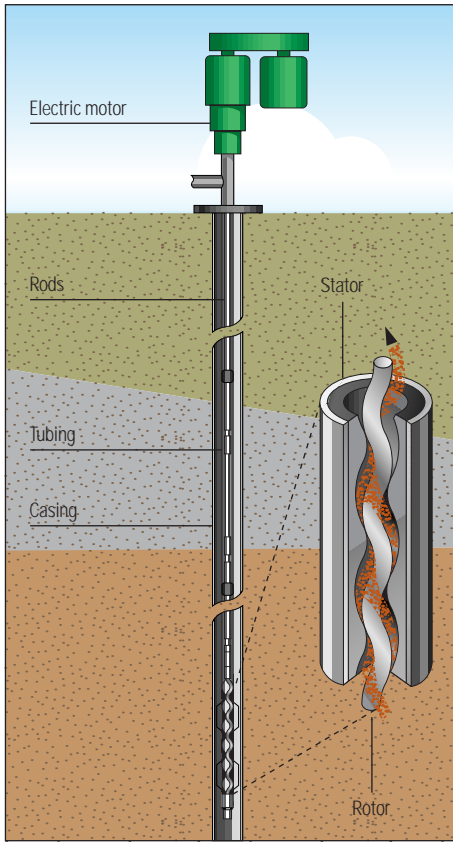
Hydraulic systems transfer energy downhole by pressurizing a special power fluid, usually light refined or produced oil, that flows through well tubing to a subsurface pump, which transmits this potential energy to produced fluids (next page, bottom left). Common pumps consist of jets, also known as venturi and orifice nozzles, reciprocating pistons, or less widely used rotating turbines. A free-floating feature allows pumps to be circulated in and out of wells hydraulically, eliminating slickline or rig operations to replace pumps or pull tubing. Hydraulic pumps are used at depths from 1000 to 18,000 ft

[305 to 5486 m] and produce rates from 100 to 10,000 B/D [16 to 1590 m³/d] or more. Many hydraulic installations produce 150 to 300 B/D [24 to 48 m³/d] from deeper than 12,000 ft [3658 m]. Heavy, viscous crudes are often easier to produce after mixing with lighter power fluids. Because pumps can be circulated out, systems can be modified for changing conditions.

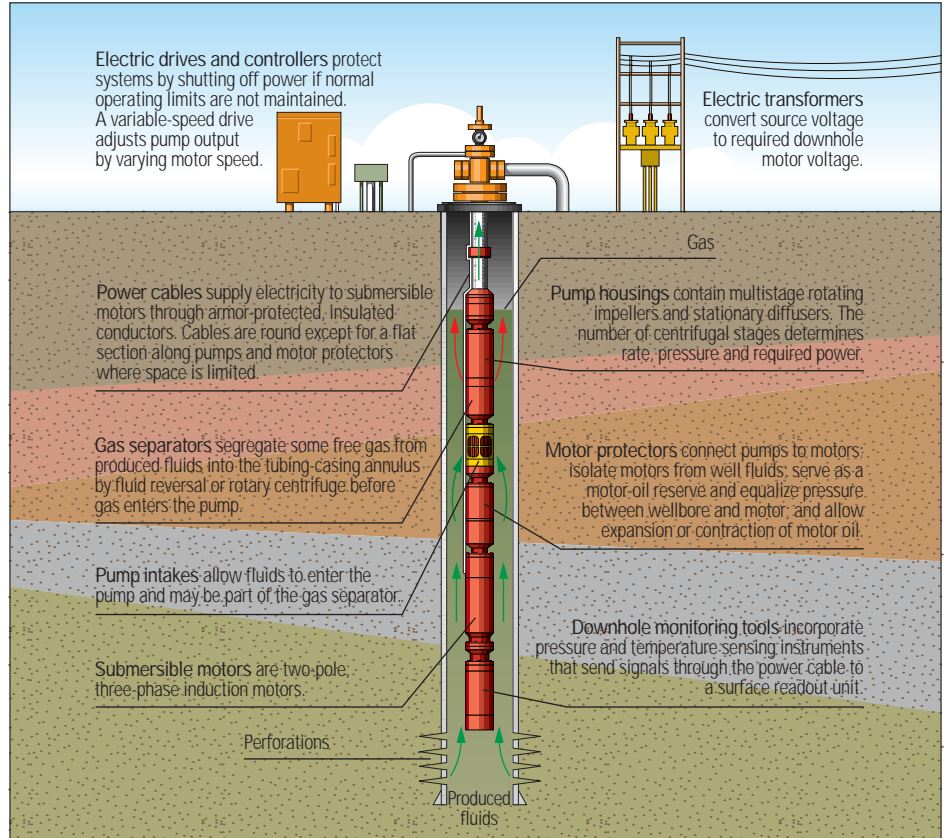
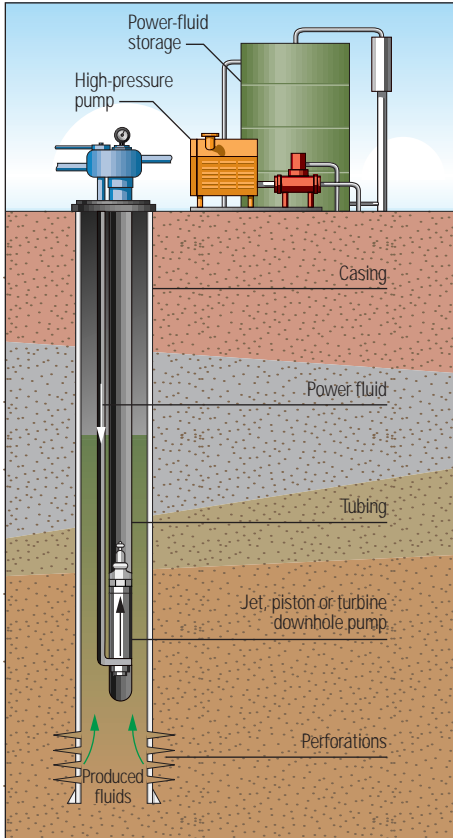
Gas lift uses additional high-pressure gas to supplement formation gas. Produced fluids are lifted by reducing fluid density in wellbores to lighten the hydrostatic column, or backpressure, load on formations. Primary criteria for this method are gas availability and compression costs. Most gas-lift wells produce by continuous injection, which is the only lift method that fully utilizes formation gas energy (next page, top right). External gas, injected into special gas-lift valves at specific design depths, mixes with produced fluids and decreases the pressure gradient from the point of injection to surface. Bottomhole pressure is reduced to provide a differential, or pressure drawdown, for required flow rates. If drawdown is insufficient, instantaneous high-volume injection, or intermittent gas lift, can be used to displace slugs of liquid to surface. The on-off nature of this option causes surface gas-handling problems as well as surges downhole that may result in sand production.

Gas lift is flexible and adjustable. Slickline-retrievable gas-lift valves can be pulled and replaced without disturbing tubing if designs or system performance need to be changed. Costs vary depending on gas source and pressure, but can be high if additional surface compressors and processing facilities are needed. Gas-lift installations handle abrasive materials like sand and can be used in low-productivity, high gas/oil ratio (GOR) wells or deviated wellbores. Natural gas shortages limit or prevent gas-lift use. Freezing and gas hydrates are problematic, as is slickline valve retrieval in high-angle wells. Scale, corrosion and paraffin increase system friction or backpressure and reduce lift efficiency. Tubing size and long flowlines also limit system pressure and restrict efficiency. The main disadvantage of gas lift is difficulty depleting low-pressure, low-productivity wells completely. In some gas-lift wells, a change in lift method may be required before abandonment.

Electric submersible systems use multiple centrifugal pump stages mounted in series within a housing, mated closely to a submersible electric motor on the end of tubing and connected to surface controls and electric power by an armor-protected cable (next page, bottom right).



^ Progressing cavity displacement pumps.



^ Hydraulic-lift pumping systems.

Submersible systems have a wide performance range and are one of the more versatile lift methods. Standard surface electric drives power outputs from 100 to 30,000 B/D [16 to 4770 m³/d] and variable-speed drives add pump-rate flexibility. High GOR fluids can be handled, but large gas volumes can lock up and destroy pumps. Corrosive fluids are handled by using special materials and coatings. Modified equipment and procedures allow sand and abrasive particles to be pumped without adverse effects. Operating submersible pumps at temperatures above 350°F [177°C] requires special high-temperature motors and cables.

Historically, electric submersible pumps were used in high-water, low-oil producers that perform like water wells. A submersible pump can operate in high-angle and horizontal wells, but should be placed in a straight or vertical section. Subsurface submersible equipment may be several hundred feet long, so bending reduces run life by causing internal wear on motor and pump bearings. Wells deeper than 12,000 ft can be produced efficiently with electric submersible systems and these pumps can be used in casing as small as 4.5-in. outside diameter (OD). At 20 to 70% efficiency, electric submersible pumps are perhaps the most efficient and economical lift method on a cost-per-barrel basis, but depth and high GOR restrict capacity and efficiency.

Another disadvantage is the need for expensive rig interventions to pull tubing for pump repairs or replacement. In addition, individual installations have limited production ranges dictated by the number of pump stages. Alternative deployment methods and variable-speed surface drives address these limitations.

> **Artificial-lift applications.** Across the spectrum of producing wells, artificial lift is applicable from simple, low-cost stripper wells where low-volume sucker-rod, progressing cavity and hydraulic lift are used most often to high-cost subsea developments. In between, there are large numbers of development, infill and secondary recovery wells that produce significant volumes of gas and oil, primarily by gas lift and electric submersible pumps. Increasingly, artificial-lift methods are being combined to overcome single-system limitations in these complex, high-volume wells.

Current Applications

Because hydrocarbon developments worldwide are in various stages of maturity, producing wells can be grouped into categories (below). At one end of this spectrum, which includes subsea completions and wells requiring advanced construction methods or new equipment technologies, there is a limited but growing number of complex, high-cost wells that produce at high rates. Sizable installation and operating costs, combined with technology or equipment constraints, limit use of artificial lift in these wells.

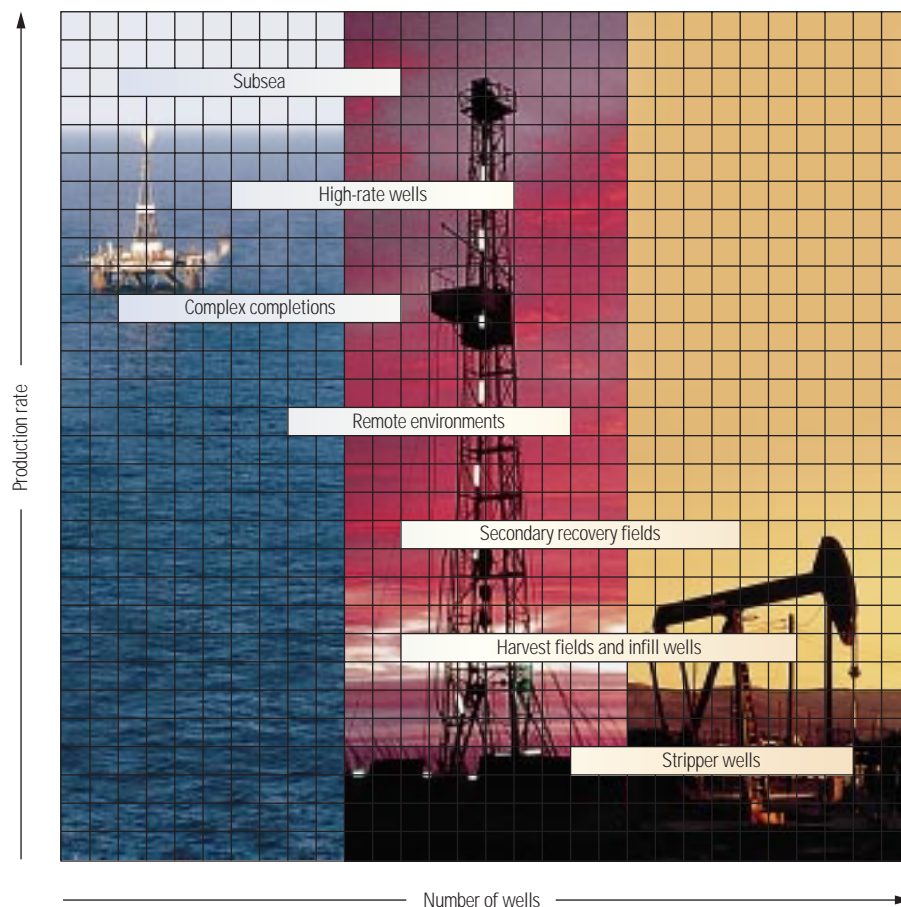
In general, this sector is not very active, but is undoubtedly the direction of future hydrocarbon development. Offshore, because of reliability and flexibility, robust gas-lift and electric submersible systems are now used almost exclusively when artificial lift is required. Exploitation of deep-water reserves requires improved technology. Alternative deployment methods and combined lift systems for subsea wells in conjunction with permanent downhole monitoring allow efficient, economic artificial lift and process control.

At the other extreme, stripper and development, or harvest, wells produce limited rates and volumes. Incremental production due to artificial lift is small. Rod, progressing cavity or hydraulic

pumps are often applied in these wells. Although well numbers are high, activity in this sector is limited to low-cost new installations and system salvage or replacement.

Between these categories are many medium-volume wells, often in secondary recovery fields, that produce significant rates and oil volumes. Incremental gains in these wells represent important potential production. These wells drive a majority of engineering and technological developments, generate cash flow, and represent the most active and high-value artificial-lift sector. Medium- to high-volume lift methods, like gas lift or electric submersible pumps, are applied in these wells. Ease of installation and operational simplicity make these two systems preferred and popular among operators.

Selection of artificial-lift methods and system designs are best accomplished by studying fields as a whole, including reservoirs, wells, surface facility infrastructure and overall project economics. Service companies play an important role by providing installation, operation, troubleshooting and optimization services in addition to artificial-lift technology, equipment and designs for specific applications.



System Evaluation and Selection

Various approaches are used to develop oil and gas assets, add value or simply to reduce the costs associated with potential prospects, new fields and late-life strategies for existing developments. Choosing the best methods involves hydraulic, mechanical and electrical engineering considerations. Ideally, artificial-lift evaluations incorporate production system parameters from reservoir boundaries to process plants.

Equipment requirements, the size and complexity of production systems and the power required to lift well fluids make high-volume artificial lift expensive to install and operate. Selecting the most suitable methods and equipment is important, because one artificial-lift installation may produce more oil than the production of some small mature fields. Selecting the right system or combination of methods is even more critical when evaluated in terms of failure, downtime and intervention costs.

Engineering teams review technical, economic and risk factors, generate options and make recommendations. The best approach is an iterative total systems evaluation, whether applied a short time after discovery when more reservoir information is known, following initial development at a stage before further drilling or when reviewing late-life strategies (right). Artificial-lift strategies should maximize options that are available over the life of a field.

Initial evaluation might indicate an artificial-lift method like electric submersible pump to obtain higher production rates, but later analysis may reveal that gas lift is best. Conversely, gas lift might be considered suitable initially because of poor submersible pump economics and equipment performance, but a review might show submersible systems to be the right approach as long as proper design, installation and operation are carried out. In some cases, electric submersible pumps are installed and operated, but when sand, scale or emulsion problems develop and actual production is reevaluated, gas lift or progressing cavity pumps might be better.

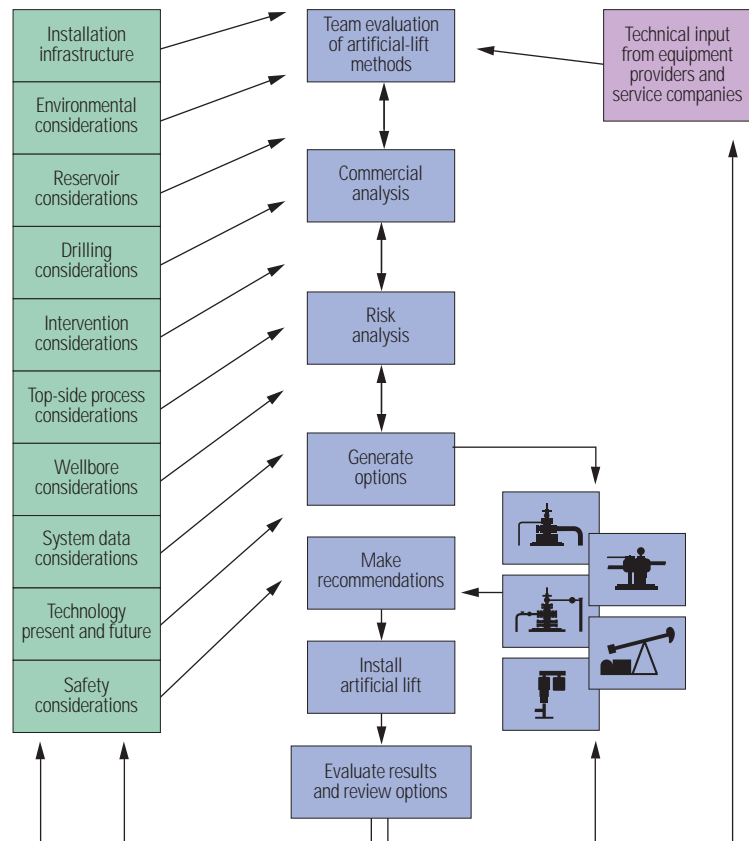
3. Bartz S, Mach JM, Saeedi J, Haskell J, Manrique J, Mukherjee H, Olsen T, Opsal S, Proano E, Semmelbeck M, Spalding G and Spath J: "Let's Get the Most Out of Existing Wells," *Oilfield Review* 9, no. 4 (Winter 1997): 2-21.

For example, a field in North Africa with declining pressure and increasing water rates appeared to be a candidate for electric submersible pumps. The reservoir has a strong waterdrive, and pressure declines about 100 psi [690 kPa] per year. No water injection is planned. The wells flow to field-gathering manifolds that connect with a pipeline linked to a distant processing plant. Increased water rates led to cessation of natural flow in some wells, indicating that artificial lift or pressure support was needed. This field appeared to be a candidate for electric submersible pump installations.

Three members of the Camco EOR Engineering Optimization Resources group conducted an artificial-lift evaluation. Flowing gradient surveys helped select the best vertical-flow correlation. Field flowline network and export pipeline pressures and rates were recorded to select a horizontal flow correlation. Water rates at which natural flow ceased were predicted and matched by NODAL techniques and well performance

models.³ Reservoir pressure and water production forecasts were used to project when the field would require artificial lift to produce high water-cut wells.

Electric submersible pump evaluation determined rates that could be achieved given reservoir and well limitations. Pump designs were generated and production benefits were quantified. Also estimated were the expected pump run life and power requirements for developing the field with submersible technology. Gas lift was evaluated for a range of well conditions over the life of the field. Injection pressure, gas-lift rate and tubing size were calculated to maximize production under existing processing facility constraints. Compressor requirements were determined from solution gas and lift-gas usage. Pipeline pressure and capacity with lift gas added to the production stream were analyzed. Gas-lift designs were generated and 20 to 40% production increases were estimated.



^ Artificial-lift evaluation. Because there are many strategies for developing oil fields, artificial-lift alternatives need to be identified and evaluated based on technical, commercial, risk and overall system factors. Engineering teams recommend development strategies and artificial-lift methods from the options generated by these evaluations. When additional reservoir, well and facility information or performance data are available, perhaps after initial field development or later during mature stages of production, these techniques are used to cycle through the process loop again to assess performance, investigate late-life strategies or reevaluate and change artificial-lift methods.

Reservoir constraints like water and gas coning, sand production and gas breakout at perforations were identified. Gas-lift and submersible pump performance were compared, and downtime was estimated based on electric pump run life and required gas-lift valve changes. Operational capability and safety issues were identified and costs were estimated. A comparison clearly identified gas lift as the optimal artificial-lift method. Intervention and pump replacements made electric submersible pumps uneconomic even though production could be increased by 30 to 40% initially. The EOR team recommended gas-lift implementation to avoid lost production. This evaluation was completed in one month.

Another example shows the complexity of lift selection. Petrobras-operated Ceara offshore production area in Brazil consists of nine platforms producing four fields—Atum, Curima, Espada and Xareu. Production from these fields was 10,550 B/D [1680 m³/d]. As a result of low reservoir pressures, all but 6 of 63 wells require artificial lift. Because of poor pump performance and scale-related failures, a proposal was made to switch from electric submersible pumps to gas lift in all four fields.

The objective was to reduce expenses and increase production by recompleting wells with single producing intervals to dual-zone producers. In general, commingling zones was restricted by wide pressure differentials. Gas lift was proposed as a solution that allowed dual zones to be produced. However, large capital expenditures were needed to convert from current electric submersible systems.

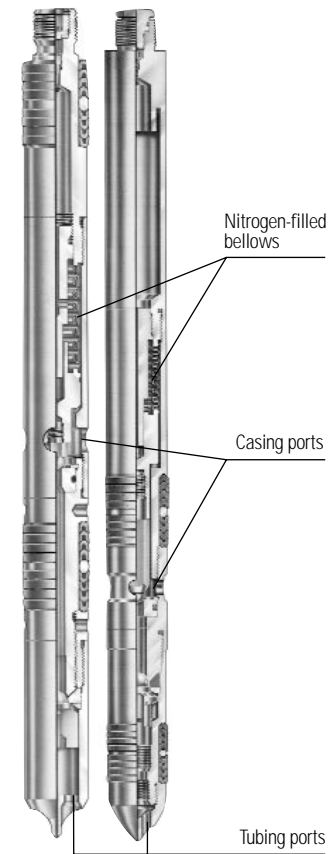
Dual submersible pump systems also allow simultaneous production of two isolated zones and are an alternative to dual gas-lift completions. Using dual submersible pumps in each well achieves the same production rates, and investment is limited to new completions for only 26 proposed dual wells. Forecast oil-rate increases of 725 m³/d [4560 B/D] to 1190 m³/d [7485 B/D] from dual zones can be achieved with gas lift or electric submersible pumps. Existing submersible installations and optional solutions were reviewed, and gas-lift viability as a replacement for submersible pumps was assessed.

Based on a flow correlation verified by flowing pressure-gradient surveys in a trial gas-lift well and NODAL analysis, field economics overall are not affected by switching from electric submersible pump to gas lift in existing wells. Scale problems are not alleviated. Gas-lift valves must be placed at depths where scale builds up, so chemical injection is still required to ensure that wells remain productive and serviceable. Gas lift does not draw reservoir pressure down as much as submersible pumps, which results in lower production rates. However, this loss of output is balanced by less downtime for gas-lift completions.

Several wells produce at low rates, particularly in the Xareu field, and flow would not be stable under continuous gas lift. In the Ceara production area, gas lift is not the ideal artificial-lift method for every well, since some wells would not continue to produce. Intermittent gas lift or progressing cavity pumps may be needed for low-rate wells. A subsea completion with low reservoir pressure that was fitted with gas-lift valves would not flow naturally. A stand-alone compressor was proposed to get this well on line.

Significant efficiency and oil output could be gained by addressing submersible pump performance. A better chemical inhibition program was needed to reduce failures due to scale and improve pump operations. Increasing run life from 16 months to 24 months reduces the number of workovers. Better designs could eliminate inefficiency, and installing two submersible pump systems per completion would cut workover frequency by half. When one pump fails, the other can be used without pulling tubing and completion equipment. Increasing submersible pump run life and improving efficiency reduce expenses. After evaluation, submersible systems still appear to be best, but reliability and life-cycle costs need to improve.

The Camco EOR group recommended that submersible pumps be retained as a primary artificial-lift method and that alternatives for reducing cost and increasing production be reviewed. One option was to use more than one artificial-lift method. By using redesigned submersible pumps and better operating practices in the Atum, Xareu and Espada fields, and converting the Curima field to gas lift, production and expense targets were achieved at reduced capital expenditure for facilities. This approach addresses the field with highest lifting costs due to short submersible pump run life and allows installation of dual gas-lift completions in the Curima field, which has the best production potential.



▲ Subsurface gas-lift valves. The choice of valve and operating principle depends on well parameters and well intervention costs. Conventional gas-lift valves and mandrels are run as part of the production tubing string. Retrievable valves in side-pocket mandrels that are offset from the centerline of the tubing are used offshore and in remote locations where rig interventions are expensive. Closing force for pressure-operated valves is provided by a spring, nitrogen-charged bellows, or both. Using a surface test rack, valves are preset to open at the required operating pressure for a well. Smaller miniature valves are available for limited clearance and slimhole applications.

Expertise is required to select, install and operate high-rate artificial lift. Aside from technical evaluation, system designs must be dependable to realize optimal value in the face of probable commercial and risk scenarios. To minimize technical and financial risks, and address specialized applications, outsourcing and results-based contracts are becoming standard practice among operators for procuring equipment and implementing artificial lift through systems design and engineering services (see "Artificial-Lift and Field Optimization," page 67).

High-Rate Gas-Lift Systems

Although trailing electric submersible pump use worldwide, gas lift—generally the most economical artificial-lift method if a cost-effective gas supply is available—is common in North America, the US Gulf Coast and offshore. Unlike submersible systems, gas lift does not add energy, or lifting power. Reservoir pressure, supplemented by gas injected into tubing valves at specific depths to lighten the fluid column, still drives fluid inflow and outflow. There are many types of gas-lift valves that use a variety of operating principles (previous page). Production engineers choose the valves that fit well and field conditions.

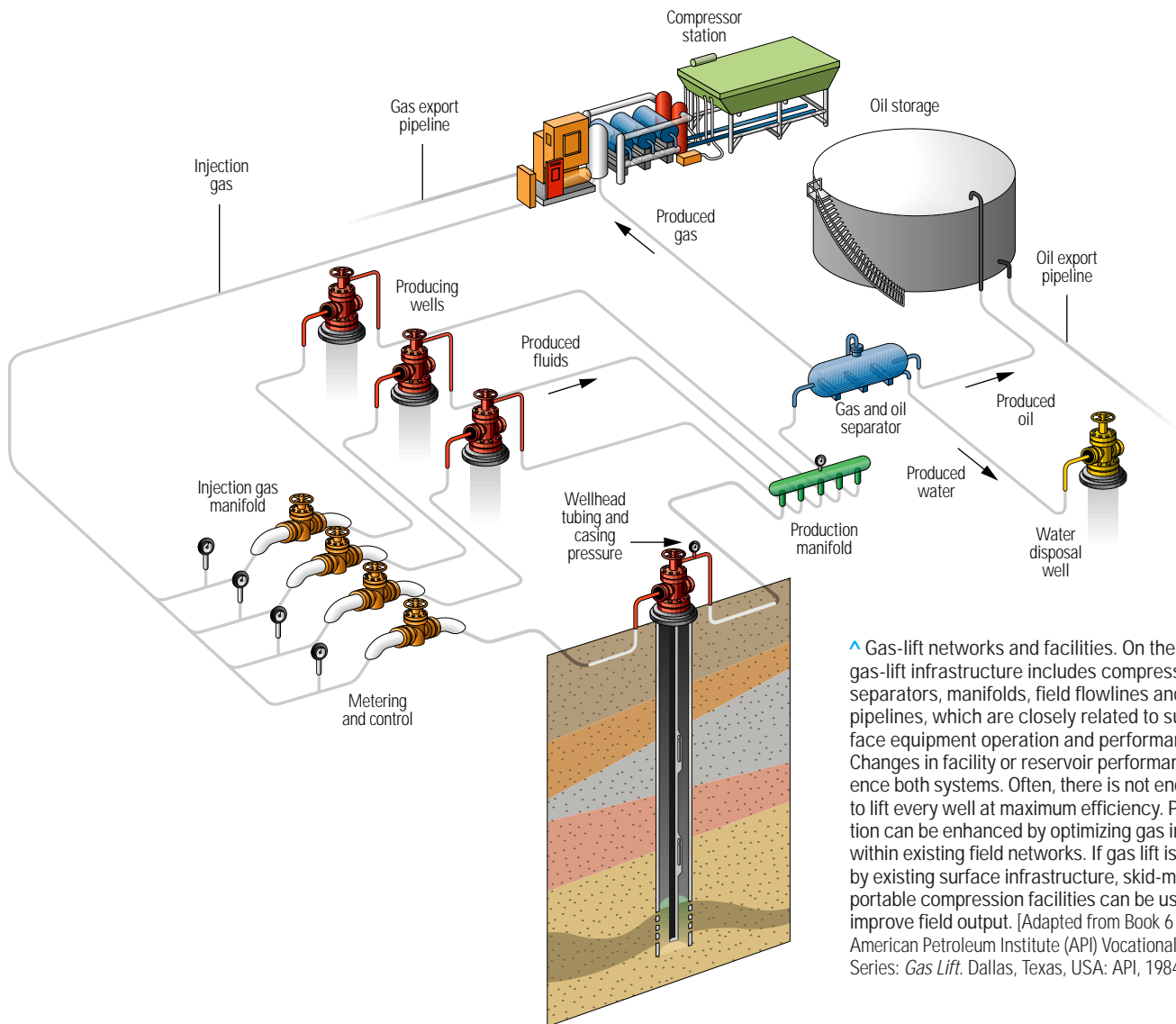
In gas-lift systems, downhole equipment and surface facilities are closely related. Because well parameters and conditions like reservoir pressure are dynamic, producing operations

change over time. By using sophisticated software to link wellbore, surface facilities and predicted reservoir response in a single model, integrated engineering teams can balance surface and subsurface considerations. Reservoir parameters are productivity, changes in performance with time and specific problems like sand or water influx. Well factors include tubing and casing size as well as depth, completion configuration—packers, perforations and sand-control screens—type of gas-lift valve, wellbore hydraulics and fluid-flow regimes. Surface facilities involve compressors, separators, manifolds, field flowlines and export pipelines (below).

Compressor discharge pressure impacts injection valve setup and operation, and is the first gas-lift design consideration. Available pressure at the wellhead establishes gas injection depth, which determines lift efficiency. The

deeper gas is injected, the higher the production rate. The cost of injecting deeper is related to additional compression, plant upgrades and operating expenses, as well as factors related to other surface facilities, like separator performance and pressures. There are, however, solutions that balance compression cost with the production rates that can be achieved.

It is important to ensure dependable gas pressure and volumes through mechanical reliability and operating procedures. Trained operators and properly installed and maintained compression equipment are crucial to gas injection. In some fields, gas lift is limited by existing infrastructure. Like gas-lift valves, compressors can also be changed. Skid-mounted, portable compression facilities can be modified for use in other locations or applications to improve outflow and minimize costs.



▲ Gas-lift networks and facilities. On the surface, gas-lift infrastructure includes compressors, separators, manifolds, field flowlines and export pipelines, which are closely related to subsurface equipment operation and performance. Changes in facility or reservoir performance influence both systems. Often, there is not enough gas to lift every well at maximum efficiency. Production can be enhanced by optimizing gas injection within existing field networks. If gas lift is limited by existing surface infrastructure, skid-mounted, portable compression facilities can be used to improve field output. [Adapted from Book 6 of the American Petroleum Institute (API) Vocational Training Series: *Gas Lift*. Dallas, Texas, USA: API, 1984.]

Surface gas compressors and subsurface valves need to operate in a stable manner, but changes in facility or reservoir performance influence both systems. Most of the time there is not enough gas to lift every well at maximum efficiency. Required injection rates often cannot be achieved because of gas source, equipment, pressure, economic or other limitations. Production output can be enhanced by effective and efficient injection gas distribution within existing field networks.

Many criteria are considered when choosing the best injection rate. For example, wells with high productivity or low injectivity need more gas volume or higher gas-injection pressure.

Sensitivity analyses determine how wells affect each other and define injection rates that result in optimal production. Gas-lift valve port, or orifice, size can be calculated and adjusted for required gas injection. Subsurface gauges supply data for subsequent evaluations. Surface and financial constraints often restrict gas throughput and need to be addressed using an integrated systems approach.⁴ In such cases, field output instead of single-well rates are optimized. For this purpose, field-wide models are built based on production system data such as compressors, separators, flowlines and chokes. Along with well performance curves, data are gathered into a field-wide NODAL analysis program.

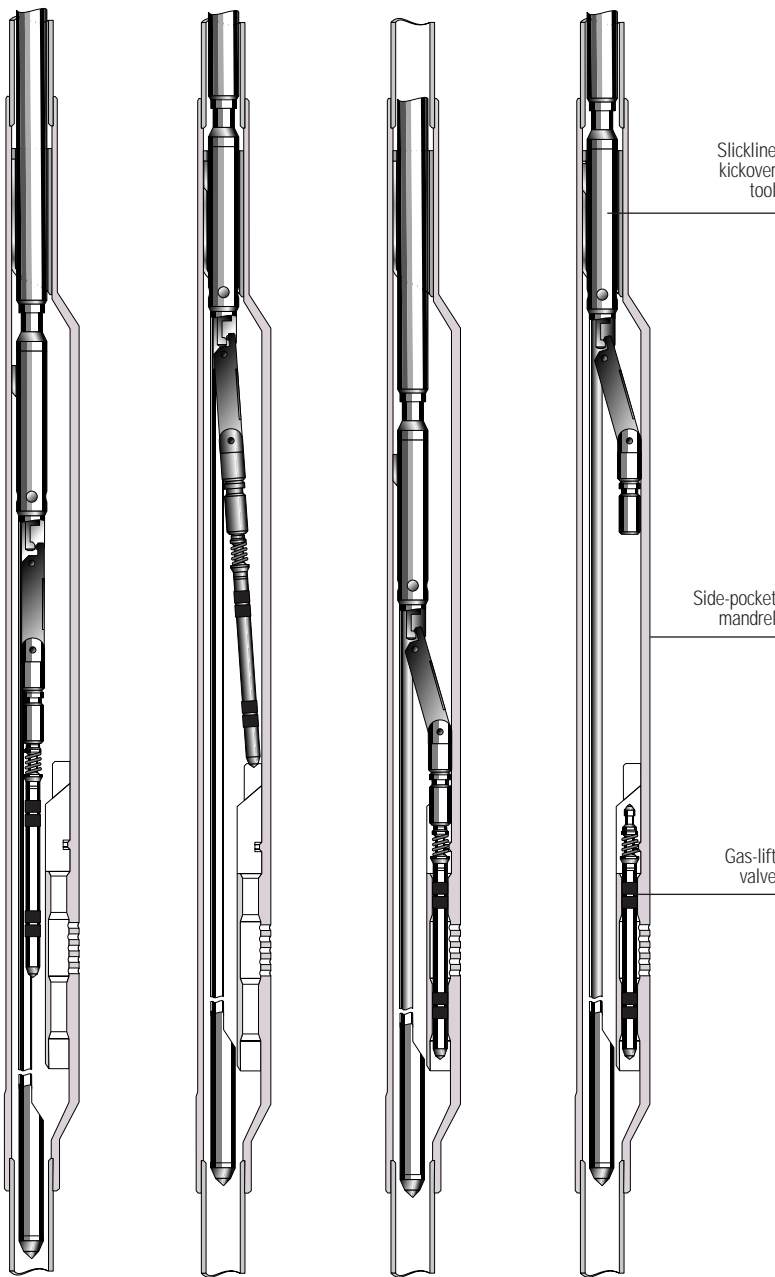
Maximizing gas-lift performance one well at a time was standard in the past. Today, ongoing production optimization and management on a system-wide basis, which includes compressors, increase revenue, enhance profitability and provide long-term value more effectively. This systems approach is made possible by improvements and advances in computing, downhole monitoring, data-collection and information technologies.

Camco, now a Schlumberger company, manufactures surface and subsurface flow-control devices, side-pocket tubing mandrels and gas-lift valves, latches, running and kickover tools for gas-lift systems (left). New technology, like electric gas-lift valves, are also being developed. Conventional valves have one port size with the capability to open and close. Simple orifice valves have no open-close mechanism. Electric valves allow port size to be adjusted remotely from surface over a range of fully open to closed. This provides better control when unloading fluids during well startup, real-time gas-lift optimization and the option of changing gas injection points without well intervention. This flexibility will help meet future oil and gas exploitation challenges by reducing gas-lift costs for deep-water and subsea wells.

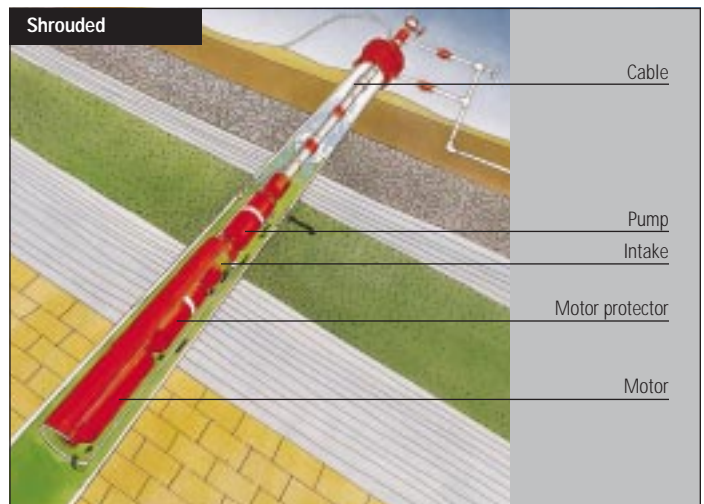
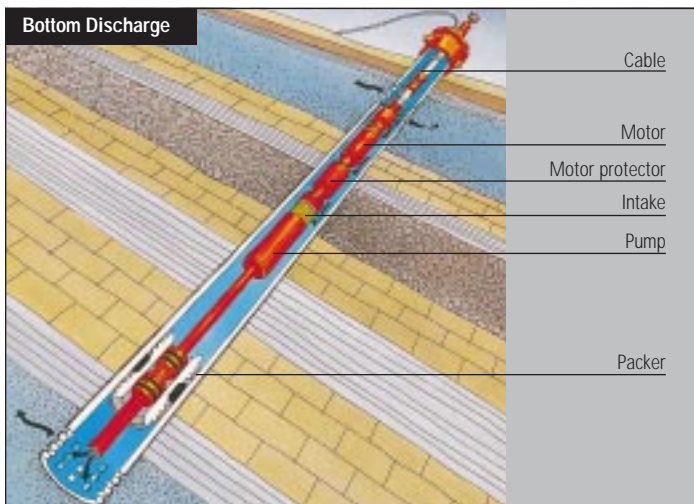
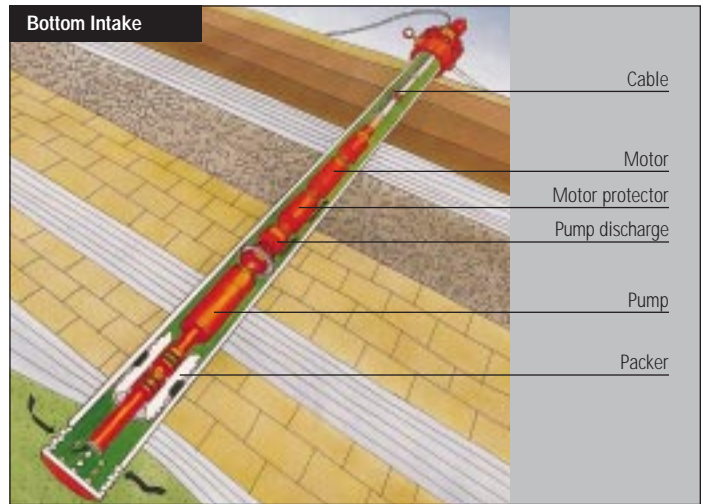
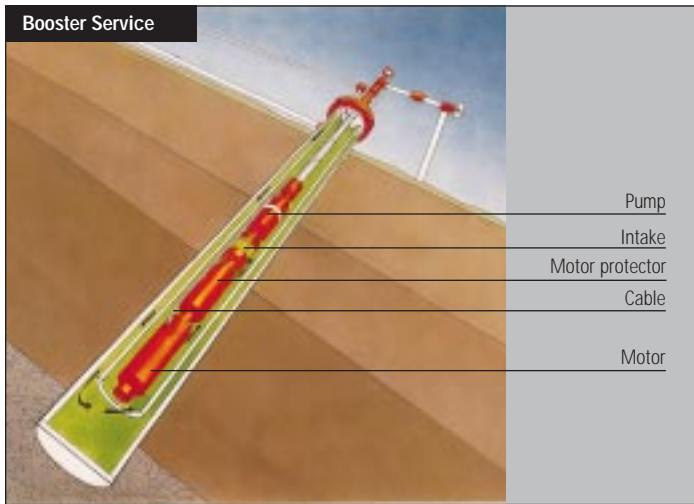
In future optimization efforts, valves will be run with gauges to read casing and tubing pressure. Combined with information currently available, such as well tests and surface pressure measurements, these readings will validate models and forecasts, and be used to establish optimum gas-injection rates. Based on required rates, port size will then be adjusted remotely. The resulting effect on casing and tubing pressure is monitored and then used as feedback for the next generation of closed-loop automated control systems.

High-Rate Electric Submersible Systems

With liquid-lifting capacities up to 30,000 B/D [4770 m³/d], depending on electric power limitations, oilfield submersible pumps are used primarily for medium- and high-volume production. Within this artificial-lift sector are several types of applications and configurations, including standard installations, booster or injection service, bottom intake or discharge, shrouded installations, offshore platforms and surface horizontal systems (next page). Design and installation of submersible systems combine hydraulic, mechanical and electrical components in a complex subsurface environment, so reliability is a key to success. If run life is short, retrieving an electric submersible pump that fails prematurely is expensive and detrimental to project economics.



▲ Retrievable gas-lift valves. Slickline-retrievable valves can be installed or removed without pulling tubing. Kickover tools are designed to selectively locate side-pocket mandrels.



▲ Submersible pump configurations. In booster service, a standard pump, protector and motor unit are used to lift fluid from flowlines or other sources and simultaneously provide injection for waterflood, pipeline or other applications. In bottom-intake configurations, fluid enters the pump through a stinger in a permanent packer. Pump and motor are inverted from conventional installations. This setup is used when casing clearance limits production because of tubing friction loss or pump diameter interference. A bottom-intake configuration pump and motor can also be suspended by small diameter, high-strength cables, conventional tubing or coiled tubing to improve output. The bottom-discharge pump is used to inject water from shallow aquifers into deeper producing zones. A shrouded configuration directs fluid past the motor for cooling or allows free gas to separate from fluids ahead of the intake and allows pumps to be set below perforations or producing zones. To save space on platforms and in other surface operations, submersible pump surface units are used for mixing mud, washing down and fire protection, sump and water supply pumps and off-loading oil from storage.

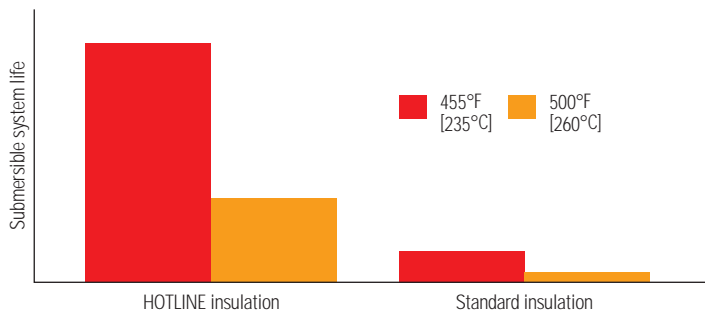
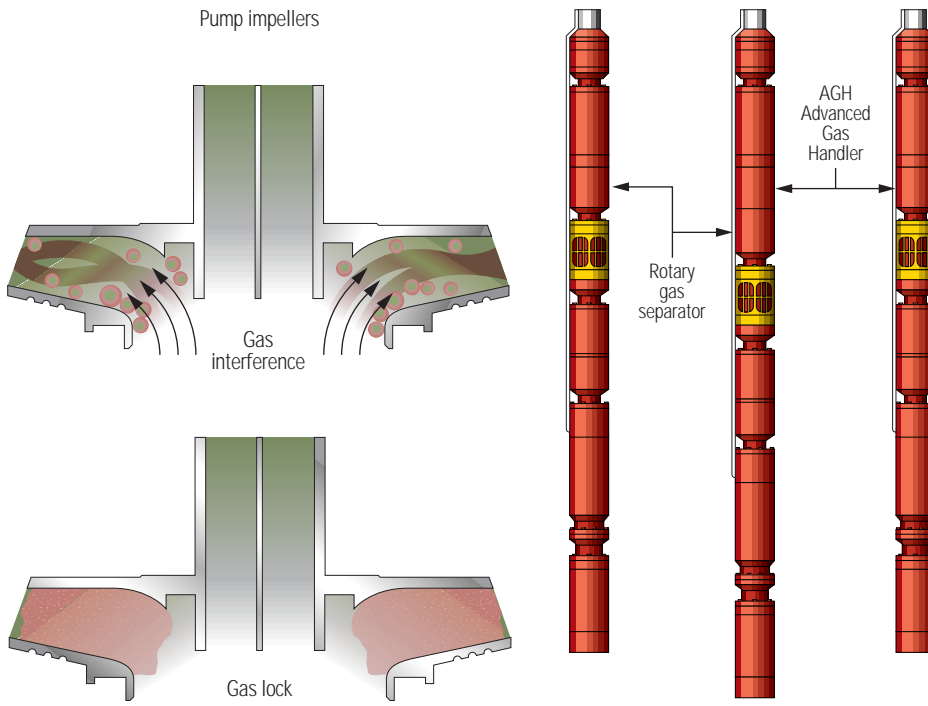
Well stimulation or chemical injection are often required, so it is important to ensure compatibility between chemicals and downhole equipment. Treatment fluids can damage coatings and elastomer components like cable, motor, pump and motor-protector seals. Improved designs and advanced construction materials, including new metal alloys and elastomers for handling corrosive fluids and harsh subsurface conditions such as extreme temperatures or high-ratio gas producers, are continuing to be developed. These new technologies, coupled with alternative methods of deploying electric submersible pumps, are expanding the range of applications for this versatile artificial-lift form.

High temperatures—For many years, electric submersible pumps were used in the Wilmington oil field, which consists of about 600 wells drilled from man-made islands in the harbor of Long Beach, California, USA, near San Diego. A subset of these wells includes low-rate, high-oil-cut producers with 9½-in. casing. The THUMS Long Beach Company operation had problems with motors that failed prematurely in about 20 of these installations.⁵ Pumps were subjected to temperatures above 400°F [205°C] because of limited oil rates and low water production that did not cool motors adequately. Pumps ran for only 30 to 60 days.

An advanced design, HOTLINE motor series with capability to run continuously at up to 550°F [228°C] was developed by Reda, also a Schlumberger company. High-temperature thermoplastic motor-winding insulation initially developed and patented for geothermal and steamflood wells was applied. This successful new technology resulted in average runs in excess of 1000 days and annual savings of over \$200,000 per well, including fewer well interventions, less equipment repair and reduced

4. Lelic O and Watt GW: "System Approach' Optimizes Gas Lift," *The American Oil & Gas Reporter* 41, no. 6 (June 1998): 124-128.

5. The THUMS (Texaco, Humble—now Exxon, Unocal, Mobil and Shell) Long Beach Company name was derived from the first letter of the five companies that joined together to bid successfully for the rights to develop and produce oil from under the city and harbor of Long Beach, California.



▲ High-temperature electric submersible pump performance. Through advanced materials, submersible technology has developed to the point that operating temperatures greater than 400°F are possible, but many factors, including design and installation, must be addressed. Critical among these are cable type, equipment sizing, cable bands and elastomers. Each component of the HOTLINE production system is modified to operate up to 550°F [288°C], which expands submersible lift use to steamfloods, geothermal applications and wells with poor cooling conditions.

deferred-production cost. A life-cycle cost comparison before and after introduction of this technology shows a significantly expanded range of submersible applications (above). These motors are used in conventional submersible pumps for better reliability, even at low temperatures.⁶

High gas volumes—Like any artificial-lift method, submersible pumps reduce flowing bottomhole pressure to obtain better inflow. In gassy wells, however, more vapor evolves from crude oil at lower pressures. At higher vapor/liquid

ratios, pump performance begins to deteriorate. If a critical vapor-liquid limit is reached, pump operation becomes unstable, surging, cavitating or stopping as gas blocks liquid flow inside pumps. Centrifugal force does not accelerate low-density vapor. In fact, gas tends to lag behind liquids and separate further, accumulating in low-pressure, low-velocity areas of pump impellers and diffusers. Vapor restricts flow through these components, causing poor lift performance. Depending on fluid types, well charac-

teristics and hydraulic design of individual pumps, vapor can completely block flow into and through submersible pumps. Catastrophic failures result if pumps are not protected from this gas-lock condition (left).

The traditional solutions to gas problems were shrouded, or tailpipe configurations, and rotary separators to remove vapor ahead of pump inlets. Production rate could also be limited, so that inlet pressure is high enough to avoid detrimental vapor/liquid ratios inside pumps. None of these solutions are optimal. Gas separators introduce other limitations and mechanical complications while robbing the system of energy in the form of gas, which lightens fluid density in the tubing just as it does in gas-lift installations. However, keeping inlet pressure high limits production and may make artificial lift uneconomic.

Field experience shows that, depending on hydraulic design and fluid characteristics, centrifugal pumps tolerate vapor concentrations of only about 10 to 20% at moderate inlet pressures. New multiphase fluid-conditioning devices like the AGH Advanced Gas Handler component provide a way to produce at higher rates and lower flowing bottomhole pressures with greater reliability and less wasted energy. The AGH module homogenizes liquid and gas entering the pump to reduce separation and accumulation in the first few pump stages, allowing submersible systems to tolerate vapor concentrations greater than 50%.⁷

Field testing performed by Intevep S.A., the research branch of Petroléos de Venezuela S. A. (PDVSA), confirmed that the AGH component can allow stable pump operation with 48% vapor entering the pump. In Lake Maracaibo, Venezuela, where AGH technology was directly applicable in production operations previously restricted by gas-lift limitations or gas interference with submersible pumps, Intevep estimated the value of this capability to be at least 75,000 B/D [11,920 m³/d] of incremental oil production from 250 wells.⁸ The AGH module can be used alone or with a traditional rotary gas separator.

Alternative deployment—Techniques for running electric submersible pumps in subsea completions and on cable or coiled tubing expand artificial-lift applications and increase production flexibility for offshore systems, remote locations with limited rig availability and high-cost workover areas (next page).

A cable-deployed submersible-lift alternative like the Reda CDPS Cable Deployed Pumping System technology reduces intervention costs by eliminating dependence on workover rigs. The system is lowered into wells with a power cable

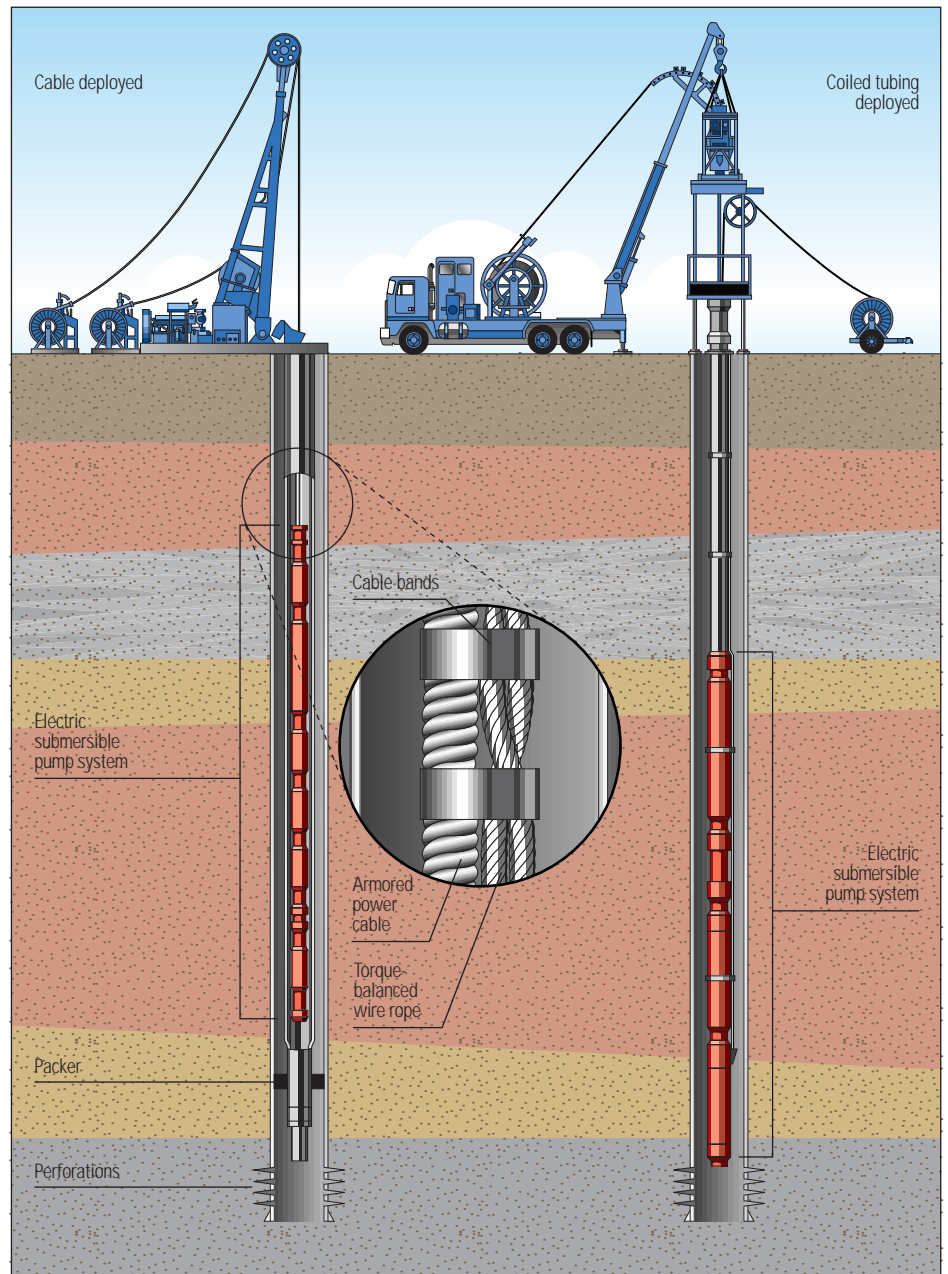
banded to a torque-balanced tension cable, and seated in a profile landing nipple of 5- or 7-in. tubing. A customized drawworks, which can be transported by helicopter to offshore platforms and remote or environmentally sensitive areas with limited access, is used to run and pull submersible systems.⁹ The CDPS lift system is inverted. Unlike typical submersible installations, running the motor on top and pump on bottom allows larger diameter, higher volume pumps to be used since there is no need for a flat motor cable and guard to run beside the pump and motor protector. Blowout preventers are available to seal around the cables.

The economics that make coiled tubing attractive for other oilfield applications in high-cost workover areas also apply for artificial-lift system deployment. Electric submersible pumps on coiled tubing pump fluids conventionally through the coiled tubing or can be inverted to produce fluids up the annulus. Power cables may be installed inside coiled tubing or banded to the outside. Internal cables are protected from mechanical damage, chemicals and well fluids.

In the Middle East, ARCO Qatar used coiled tubing with internal power cables to deploy submersible pumps and produce fluids up the annulus inside 7-in. production tubing.¹⁰ In Brunei, Shell converted a well from gas lift to high-rate electric submersible pump with a rigless workover made possible by a coiled tubing deployed system.¹¹ Offshore, coiled tubing expands submersible pump applications when through-tubing installation is feasible, reducing the need for conventional rig workovers and minimizing downtime as well as deferred production. This unique, flexible technique has potential in small or marginal offshore fields where no gas-lift infrastructure exists.

Subsea completions—Flow from subsea wells is driven by reservoir pressure supplemented with gas injection when necessary. However, if wells are far from host platforms, gas lift is inefficient because of long flowlines. Well-to-platform distance is limited by the capacity of gas-lift injection and reservoir pressure, which declines as fields are depleted and water cut increases, to drive outflow. Distances greater than 8 miles [13 km] are considered uneconomic.¹²

Compared with gas lift, submersible pumps are not as adversely affected by well-to-platform distances and offer increased flow rates. Subsea submersible installations were not feasible until recent advances in wet mateable connections. These connectors allow seafloor electrical tie-ins and eliminate the need for dry connections to be made at the surface. Offshore reservoirs that are uneconomic to operate by conventional means



Alternative deployment techniques. Cable-deployed and coiled tubing submersible pump systems are designed to reduce expenses and production downtime associated with remote or high-cost wells and offshore platforms where space and rig availability are limited.

6. Fuller D, Fickes B and Dowdy R: "Electric Submersible Pumping Systems Applied in High-Temperature Environments," presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 27-29, 1994.

7. Kallas, P and Way K: "An Electrical Submersible Pumping System for High GOR Wells," presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 26-28, 1995.

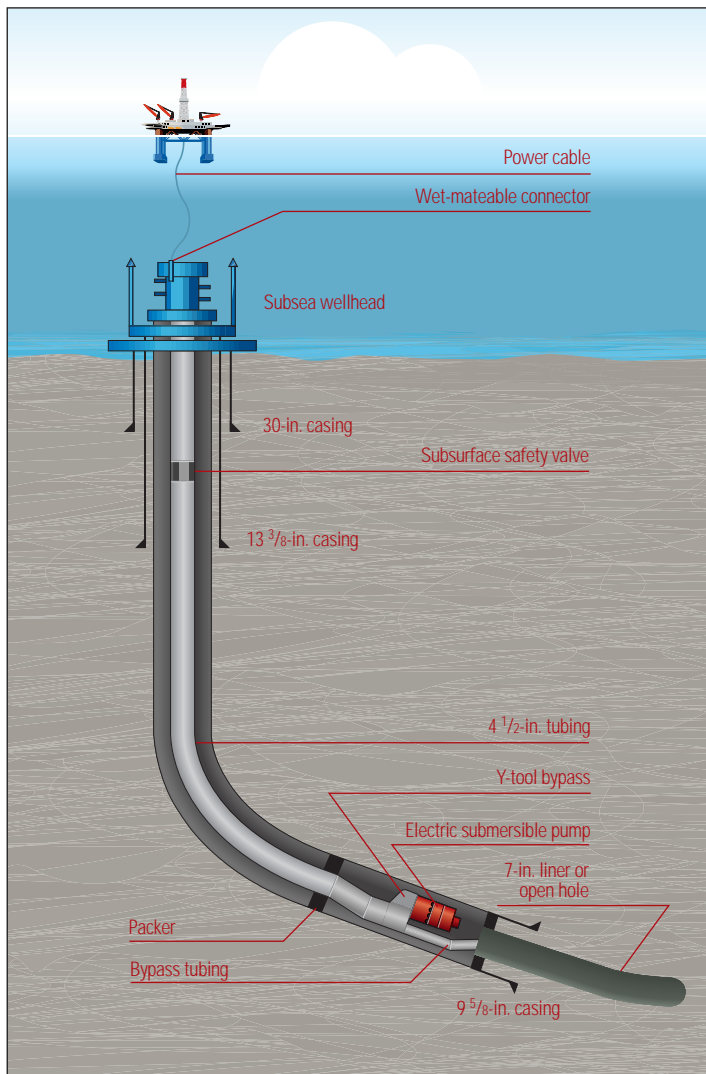
8. Castro M, Pessoa R and Kallas P: "Successful Test of New ESP Technology for Lake Maracaibo Gassy Oil Wells," presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 28-30, 1999.

9. Toubar M, Bahaa H and Guindi R: "Cable Deployed Pumping System Case Study," presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 28-30, 1999.

10. Patterson JC, Stamey RC, Penny R and Dwiggins JL: "Coiled Tubing and Electrical Submersible Pump Technology Improve Field Evaluation Cost," presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 30-May 2, 1997.

11. Pastor G, Knoppe R and Shepler R: "South China Sea Gas Lifted Well Conversion Utilizing Coil Tubing Electrical Submersible Pumping Systems," presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 28-30, 1999.

12. Al-Mashgari A, Breit S, Christmas D, Leslie D and Smith J: "Subsea Electrical Submersible Pumps at Large Step-Out Distances," paper SPE 38537, presented at the 1997 SPE Offshore Europe Conference, Aberdeen, Scotland, September 9-12, 1997.



can now be produced with submersible lift. Operating satellite wells at greater distances means that fewer platforms are needed; host platforms can be in shallow water; and marginal fields can be produced without platforms, which reduces initial costs and operating expenses.

Electric submersible pumps offer many benefits over other artificial-lift methods in subsea applications. The capability to operate wells farther from host platforms is the most important, but other benefits include improved well performance, reduced capital costs and lead times, improved energy efficiency and less environmental impact. The first subsea submersible pump was installed in Brazil for Petrobras in 1994.¹³ To maximize recovery over a five-year production

contract, the BP Amoco plc Lihua field in the South China Sea employs 24 of 29 subsea submersible pumps in operation today, all installed by Reda (above).¹⁴

For electric submersible pump systems, Reda manufactures and supplies multistage centrifugal pumps, motors, protectors, gas-handling equipment, power cables, surface variable-speed drives (VSD) and controllers, and other accessories. In future submersible systems, vital operating statistics from fields or wells can be gathered by surface instrumentation and reliable permanent downhole gauges to be transmitted by Supervisory Control and Data Acquisition (SCADA) systems to offices where data are processed.

Pump inlet and outlet pressures, well and motor temperatures, insulation resistance, system vibration and power supply can be interpreted using software to make decisions, identify or prevent pump problems and premature failures, monitor performance and evaluate operating options. Then, before actions are taken, NODAL analysis is used to simulate new system conditions and validate motor frequency. If results look good, executable commands are transmitted to the well or field. Advanced variable-speed drives will be able to change operating speeds automatically based on downhole measurements and estimated torque to avoid electric current fluctuations in motors.

Design, Installation and Operation

Artificial-lift methods work well if systems are designed and installed properly. Changing reservoir and well conditions need to be anticipated so that proper equipment is selected and installed to ensure flexibility. Availability of data is important to achieve good designs that work effectively in the field. In gas-lift design for example, well data, completion diagrams, well deviation, gas-lift equipment, surface production system information, and reservoir and fluid characteristics are basic requirements. Good pressure-volume-temperature (PVT) data with flowing pressure and temperature surveys improve designs. The less uncertainty, the more economical the design.

This principle also applies to other artificial-lift designs. In electric submersible designs, oversized or undersized pumps and motors, which cause inefficient energy consumption and shorter pump life, are often the result of limited or poor data. Variable speed drives can avoid these problems, but may add to project capital expenditures.

Good data may have been available in the past, but those designing artificial-lift systems did not always have access to this information due to inadequate communication within operating companies or with pump manufacturing and service companies. Reorganized and realigned business units focus information and experience locally rather than company-wide. This trend requires more openness between operators and service providers to share nonconfidential information. Companies and operating areas need to share knowledge and data efficiently to benefit fully from isolated pockets of industry expertise and experience.

Once installed, artificial-lift systems must be operated and managed. In gas-lift systems, stable gas-injection pressure and rate are important to prevent gas from being injected into multiple valves or short circuiting above the operating-valve design depth. Effective monitoring provides early indication of submersible pump problems, so preventive steps can be taken or future well interventions can be scheduled. If artificial lift fails, these data can be used in failure analysis and contribute to a process of continuous improvement. Teamwork among production, reservoir, completion and artificial-lift engineers, related disciplines, equipment providers and service suppliers is a key to production optimization.

Artificial-Lift and Field Optimization

Maximizing field value is an important, but difficult and often neglected task. Optimizing production well by well is one way to improve field output, but this approach is limited by constraints from other wells and facilities. Another approach is to look at entire production systems—wells, reservoirs over time and surface networks. In this way, constraints can be identified and eliminated. On an individual-well basis, optimization is carried out using single-rate and multirate well test results. When a group of wells is addressed, more involved methods from spreadsheets to field models may be needed.

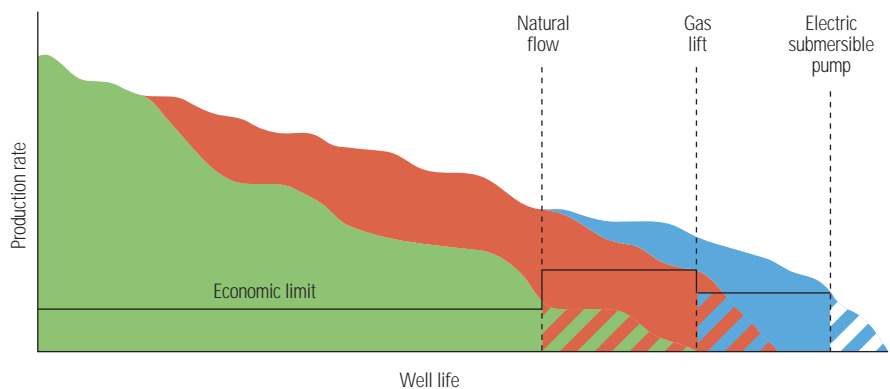
The value of production optimization may be difficult to quantify and varies from case to case. Incremental production above baseline decline curves through focused production management and continuous optimization is the objective (right). The area under production curves between optimized and baseline rates represents cumulative incremental production and ultimately additional reserve recovery, particularly when ultimate abandonment pressure can be reduced. Added value can be significant, especially in large fields. Experience shows that 3 to 25% incremental production can be achieved with production optimization. This percentage varies, depending on the degree of optimization that has already been achieved and the quality or age of the original production system.

A modest 1% improvement in production rates may deliver millions of dollars in added value. Three to 25% increases equate to tens of millions of dollars per year in added revenue. Moreover, value is delivered not just from increased production, but also by better gas or power usage, reduced operating costs and lower capital expenditures. For example, after existing wells are optimized, fewer new or infill development wells may be required. Whatever the level of production performance—from basic data acquisition, system control and communication to the actual optimization process—more is achieved with a systemized plan implemented and followed in a disciplined, structured approach.

When optimization is considered, often the first thought is in relation to gas-lift oil fields. Today, however, the approach and tools to achieve optimization allow all producing systems—natural flow, gas lift, electric submersible pump and gas wells—to be considered. Moreover, this process lends itself to performing short studies to assess commercial and technical impacts of alternative development scenarios and provide important data for decision-making and field management. Before optimization begins or strategic, economic and design choices are made, it is necessary to evaluate production systems. This includes topside compressors, flowlines, manifolds and separators; wellbore submersible pump or gas-lift design and operation, fluid hydraulics and completion designs; reservoir productivity and changes with time, sand or water problems; and operating environments from geographic location to type of installation and export method.

Computer models aid in production system optimization. It is essential to have simulations that match reality by adjusting well and surface parameters—formation damage, tubing, flowline compressors, separators, manifolds, pipelines and a flow correlation—in models. Often simulations that match measured, or known, cases are used as a predictive tool. Therefore, regularly scheduled well tests are an important component of modeling and optimization. As predictive tools, models are used to perform “what-if” scenarios and sensitivity analyses on different parameters to evaluate options. Continuous monitoring of compressor pressures, gas-injection rates or electrical amp charts in submersible systems is needed. These data are used to update models regularly and match actual well tests so that field conditions are represented accurately.

By studying oil and gas operations as complete systems, the most economic development strategies are identified. Surface equipment and facilities, well completion configurations, reservoirs and operating environments are all taken into consideration. Over the productive life of a field, optimization includes well modeling and monitoring, liaison between field and office personnel, reconciling model predictions with measured data, updating recommendations periodically, training, data management and regular reporting of actual performance against targets. How far this process is taken depends on existing conditions and limitations. In some cases, drilling new wells might cost less than optimization work. Therefore, a comprehensive study is needed before making decisions.



▲ Unlocking value: area under the curve. Incremental production value may be difficult to define because it varies from case to case, but output above a baseline decline is the target of artificial-lift optimization. The difference between initial output and enhanced production is cumulative additional production, or reserve recovery. Artificial lift increases the area under decline curves by improving production rate, extending well life and reducing ultimate abandonment pressure. Changing from one artificial-lift method to another may be necessary to further reduce flowing bottomhole pressure and maximize reserve recovery.

13. Mendonca JE, Hodge RC, Izetti R, Nicholson A, Dwiggins JL, Morrison D, Cia M and Alfano PP: “First Installation of an Electrical Submersible Pump in a Subsea Well,” presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 26-28, 1995.

14. Baillie AR and Chen Jing Hue: “Liuhua 11-1 Field Development: An Innovative Application of Technology,” presented at the SPE Electrical Submersible Pump Workshop, Houston, Texas, USA, April 29-May 1, 1992.

Forties field is a decade-long example of ongoing artificial-lift optimization in a harsh off-shore environment where both gas lift and electric submersible pumps are utilized. This North Sea development consists of four main platforms produced predominantly by gas lift and a smaller platform lifted exclusively by electric submersible pumps. Within the main field platforms, submersible systems have been used strategically for tasks ranging from starting up platforms to proving new technologies. Submersible pump operations began in the late 1980s and gas lift was initiated in the early 1990s. Incremental gains from gas-lift optimization continue to increase, and electric submersible pump reliability as well as run life have increased steadily with improvements in operating techniques. A value-pricing arrangement led to \$50 million in project savings over five years.

Initially, a gas-lift group focused on supporting more than 40 gas-lifted wells through studies, designs, monitoring, performance analysis, training and trouble-shooting problems. Over time, a structured management process evolved that included gas lift, reservoir surveillance and production engineers and encompassed all aspects of providing gas lift to the fields. Another team concentrated on a systems approach to electric submersible pump installation and operation with the goal of improving run life and establishing an agreement between operating and service companies that shared the financial risk of pump failures as well as the benefits of prolonged production.

Team members are involved directly in analyzing and selecting artificial-lift methods best suited to meet short- and long-term field development goals. This approach brings new technologies forward to address a variety of issues from reservoir constraints to cost reduction. Combining gas-lift and electric submersible pump

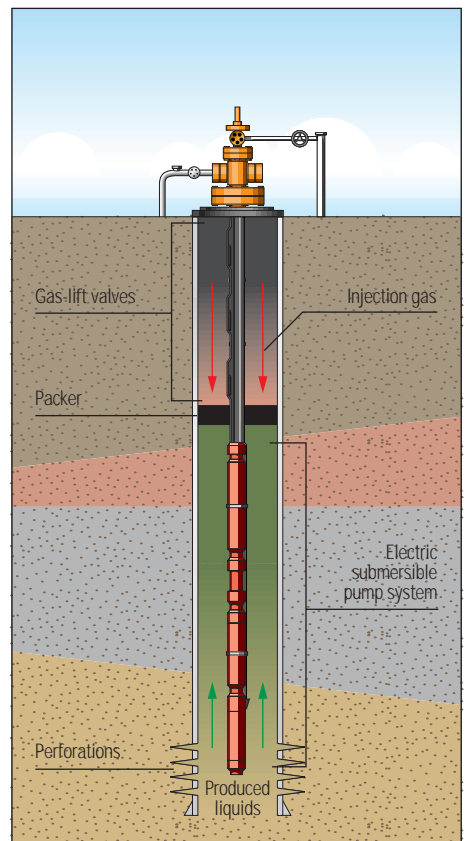
expertise helps to better define and manage production. Today, an integrated team is modeling the field, and networking all the wells and associated infrastructure. This will allow strategic and economic decisions to be made that take into account a variety of constraints from platform electricity generation, gas compression, flow-lines, separators, gas availability and water handling to subsurface pump performance, motor power, pump stages, pressure drawdown limits and well geometry.¹⁵ This asset is in decline, but substantial recoverable oil remains.

The next technological step is for optimization to be performed in real time with automated closed-loop systems. Automation can be applied at different levels, from semi-automatic—still involving field personnel to gather data or adjust valves and engineers to make decisions—to fully automatic computerized systems. Automation can be done using simple proportional-integral-differential (PID) or complicated fuzzy-logic control systems.

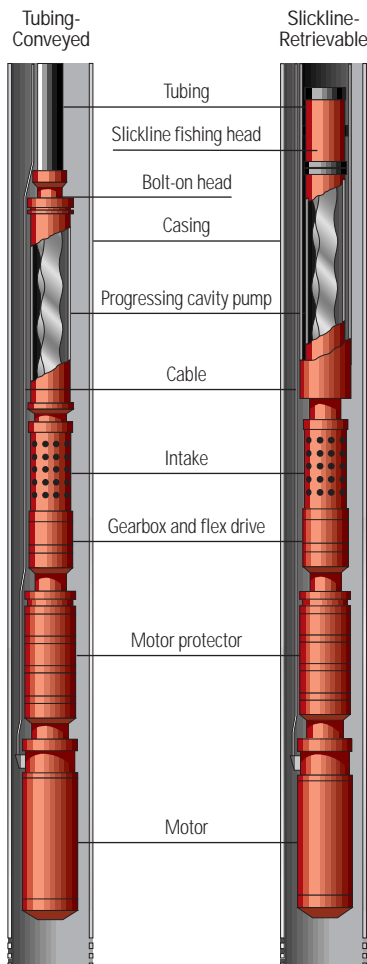
Combining Systems Downhole

There is a trend toward artificial-lift method combinations to yield higher rates at lower cost, under better operating conditions and with more production flexibility than could be expected from just one method. These approaches overcome restrictions and limitations of individual methods such as tubing sizes, operating depth, high water rates and corrosive conditions. Combined lift systems are also more adaptable to changing operational conditions, resulting from reservoir pressure depletion, gas injection for pressure maintenance and secondary recovery water-floods. Combined lift methods reduce equipment requirements and power consumption, and yield beneficial results in terms of costs, investments and asset value.

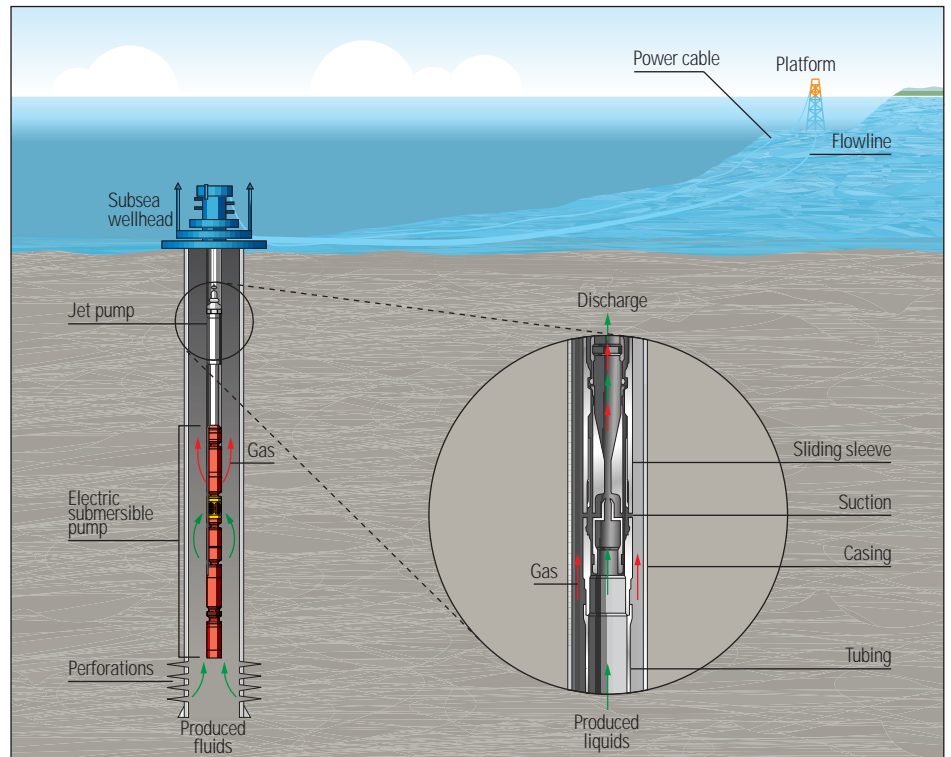
For example, combining gas lift and electric submersible pumps in the same well offers many opportunities to enhance production, optimize flow rates and ensure uninterrupted operation. Gas lift in a combined installation provides a backup in case electric submersible pumps fail and can be used prior to pump startup to unload wells or stabilize wells that produce excessive gas or sand (below). Applications that operate both systems concurrently include using a submersible system to extend the life of an existing gas-lift installation. The submersible pump acts as a bottomhole pressure booster to increase the flowing pressure at the gas-injection depth. From the standpoint of design, electric submersible pumps develop greater flowing bottomhole pressure differentials than gas lift for a given rate. Simultaneous gas lift and submersible pump operation allows smaller pumps and motors to be used. Cost-savings can be utilized to install systems with advanced materials and designs that handle harsh conditions and extend pump and motor life.¹⁶



Progressing cavity pumps are popular for producing fluids with high-solids content, aromatic condensates and tight emulsions as well as heavy crudes, especially in high-angle wells. In nonvertical wells, however, conventional surface-driven systems experience rod failure and wear-induced tubing leaks. Various rodless systems are being used to solve these problems. One alternative is a bottomdrive configuration that uses a power cable, submersible motor, protector and flexible gearbox to drive progressing cavity pumps. This eliminates rod breaks, tubing wear and wellhead leaks, which reduces downtime and repair costs. The primary cause of progressing cavity system failure is pump wear. Harsh subsurface conditions reduce pump performance and efficiency, but electric submersible pump motors and drive components are usually unaffected and can be rerun.¹⁷



▲ Subsurface-motor-driven progressing cavity pumps. Using progressing cavity pumps is a way to lift heavy oil and high-solids content fluids. Rodless, bottomdrive progressing cavity pumps eliminate rod failures, tubing wear, rod torque and back spinning, and surface wellhead leaks, which are major problems in conventional surface-driven systems.



▲ Combining submersible and jet-pump lift systems. Using a jet pump above the discharge of electric submersible pumps allows gas segregated into the tubing-casing annulus by a rotary gas separator to be compressed and injected back into the liquid stream being boosted to surface by the submersible pump. Prototype testing proved that this combination of artificial-lift methods can be used offshore, especially in deep water, where individual flowlines to vent annulus gas are complex and expensive to install.

Deployment alternatives include conventional tubing or coiled tubing. Using slickline or coiled tubing to replace pumps without pulling the drive assembly offers order-of-magnitude cost-savings and makes combined systems attractive in high-cost areas if pumps fail frequently (left). Slickline-retrievable, bottomdrive progressing cavity pumps were evaluated originally for the Alaskan North Slope of the USA, where conventional workovers cost \$200,000, but slickline operations cost \$20,000. Wireline-retrievable progressing cavity lift systems were recently used in highly deviated wells in Southeast Asia with sand, scale or heavy-oil problems and small-diameter tubulars. When a failure occurred, the operator was able to retrieve and replace the pump.

In subsea applications, artificial lift must operate effectively with multiphase gas-liquid mixtures since it not practical to use the tubing-casing annulus for downhole separation or vent produced gas from the casing to an extra flowline for each well. Prototype testing proved that hydraulic jet pumps can be operated in combination with electric submersible pumps to allow production of high gas/liquid ratio wells in deep water. A rotary gas separator (RGS) to reduce the

volume of free gas that enters the pump intake, increases pump performance. Placing a jet pump in the tubing above the electric submersible pump discharge allows gas segregated into the annulus by rotary separation to be compressed and injected back into the liquid flow stream that is pumped to surface by the submersible pump (above). The power fluid is the liquid—produced fluids less free gas—pumped by the electric submersible pump. The jet-pump intake fluid is the free gas that was separated upstream of the electric submersible pump intake.¹⁸

Gas lift and electric submersible pumps have been used for decades, but new developments are still being introduced. Separating oil and gas downhole, subsurface dewatering and disposal, and horizontal electric submersible pump systems for surface oil and gas operations are just some of the future applications for artificial-lift technology. Combining production processes downhole to provide environmentally friendly solutions that improve profitability blurs the distinctions between various artificial-lift methods, and between subsurface equipment and surface facility functions.

—MET