Overview of Artificial Lift Systems

Kermit E. Brown, SPE, U. of Tulsa

Summary

This paper gives guidelines to assist in the selection of artificial lift methods. The most important guideline is determination of the flow rates possible by each method. This requires preparation of pressure/flow rate diagrams combining well-inflow performance relationships with tubing intake curves. The tubing intake curve includes pressure loss in the complete piping system and/or pressure gains by the pumping method. Many other factors other than rate, such as location, retrievability by wireline, corrosion, paraffin, scale deposition, cost, operating life, and others, influence the final selection of lift equipment.

Introduction

This paper provides an overview of artificial lift systems and gives guidelines indicating when one system is better to use than another. Advantages and disadvantages are given with examples in the selection of lift methods.

This list represents the relative standing of lift systems based on the number of installations throughout the world: (1) sucker rod pumping (beam pumping), (2) gas lift, (3) electric submersible pumping, (4) hydraulic piston pumping, (5) hydraulic jet pumping, (6) plunger (free-piston) lift, and (7) other methods. This differs according to field, state, and country.

New lift systems are being developed and tested continually. The lifting of heavy viscous crude oils requires special attention, and methods designed specifically for this purpose are being tested. Wells located offshore and in deep water present specific problems, and surface-space limitations become important. The artificial lift method should be considered before the well is drilled. Obviously this cannot be done on wildcat wells, but it must be done on all subsequent development wells. The drilling program must be set out to ensure hole sizes that permit adequate casing and tubing sizes.

0149-2136/82/0010-9979$00.25

One serious limitation to artificial lift installations has been the installation of small casing sizes, which limits the installation to specific tubing sizes to obtain the objective flow rate and, in particular, limits the size of retrievable gas lift equipment and/or pumping equipment. The installation of gas-lift mandrels that accept only 1-in. (2.5-cm) OD gas-lift valves is common in the U.S., and serious limitations on gas passage volumes are imposed on the system with this small valve. Also, the better performance characteristics of the 1½-in. (3.81-cm) OD valve are lost. For the pumping systems, the smaller capacity pumps must be used in the smaller casing sizes, and sometimes the advantage of retrievable pumps is lost.

Surface-space limitations become an important factor. For example, if large compressors for gas lift or large generators for electrical pumping are anticipated for offshore platforms, provisions must be made in the original design to allow for both weight and space on the platforms. Some engineers are invariably optimistic about natural flow in the planning stage, and in many instances they still maintain that artificial lift will not be required during the life of a field. This leads to very poor planning, especially on offshore facilities.

In the design of artificial lift systems for a well, it is recommended that it initially be treated as if it were a flowing well—i.e., a production systems graph should be prepared to see if the well is capable of flowing and, if it is, at what rate. The artificial lift analysis can be placed on the same plot. Numerous flowing wells will show increased flow rates when placed on artificial lift.

The purpose of any artificial lift system is to create a predetermined tubing intake pressure such that the reservoir may respond and produce the objective flow rate. The design and analysis of any lifting system can be divided into two main components. The first is the reservoir component (inflow performance relationship), which represents the well's ability to produce fluids. The

TABLE 1—RELATIVE ADVANTAGES OF ARTIFICIAL LIFT SYSTEMS *

Rod Pumping	Hydraulic Piston Pumping	Electric Submersible Pumping	Gas Lift	Hydraulic Jet Pump	Plunger Lift
Relatively simple system design.	Not so depth limited—can lift large volumes from great depths, 500 B/D (79.49 m^3/d), from 15,000 ft (4572 m). Have been installed to 18,000 ft (5486.4 m).	Can lift extremely high volumes, 20,000 B/D (19 078 m^3/d), in shallow wells with large casing. Currently lifting $\pm$120,000 B/D (19 068 m^3/d) from water supply wells in Middle East with 600-hp (448-kW) units; 720-hp (537-kW) available, 1,000-hp (746-kW) under development.	Can handle large volume of solids with minor problems.	Retrievable without pulling tubing.	Retrievable without pulling tubing.
Units easily changed to other wells with minimum cost.	Crooked holes present minimal problems.	Unobtrusive in urban locations.	Handles large volume in high-PI wells (continuous lift), 50,000 B/D (7949.37 m^3/d).	Has no moving parts.	Very inexpensive installation.
Efficient, simple and easy for field people to operate.	Unobtrusive in urban locations.	Simple to operate.	Fairly flexible—convertible from continuous to intermittent to chamber or plunger lift as well declines.	No problems in deviated or crooked holes.	Automatically keeps tubing clean of paraffin, scale.
Applicable to slim holes and multiple completions.	Power source can be remotely located.	Easy to install downhole pressure sensor for telemetering pressure to surface via cable.	Unobtrusive in urban locations.	Unobtrusive in urban locations.	Applicable for high gas oil ratio wells.
Can pump a well down to very low pressure (depth and rate dependent).	Analyzable.	Crooked holes present no problem.	Power source can be remotely located.	Applicable offshore.	Can be used in conjunction with intermittent gas lift.
System usually is naturally vented for gas separation and fluid level soundings.	Flexible—can usually match displacement to well's capability as well declines.	Applicable offshore.	Easy to obtain downhole pressures and gradients.	Can use water as a power source.	Can be used to unload liquid from gas wells.
Flexible–can match displacement rate to well capability as well declines.	Can use gas or electricity as power source.	Corrosion and scale treatment easy to perform.	Lifting gassy wells is no problem.	Power fluid does not have to be so clean as for hydraulic piston pumping.	
Analyzable.	Downhole pumps can be circulated out in free systems.	Availability in different size.	Sometimes serviceable with wireline unit.	Corrosion scale emulsion treatment easy to perform.	
Can lift high-temperature and viscous oils.	Can pump a well down to fairly low pressure.	Lifting cost for high volumes generally very low.	Crooked holes present no problem.	Power source can be remotely located and can handle high volumes to 30,000 B/D (4769.62 m^3/d).	
Can use gas or electricity as power source.	Applicable to multiple completions.		Corrosion is not usually as adverse.		
Corrosion and scale treatments easy to perform.	Applicable offshore.		Applicable offshore.		
Applicable to pump off control if electrified.	Closed system will combat corrosion.				
Availability of different sizes.	Easy to pump in cycles by time clock.				
Hollow sucker rods are available for slim hole completions and ease of inhibitor treatment.	Adjustable gear box for Triplex offers more flexibility.				
Have pumps with double valving that pump on both upstroke and downstroke.	Mixing power fluid with waxy or viscous crudes can reduce viscosity.				

*Reprinted with permission from S. Gibbs, Nabla Corp., Midland, TX, with modifications by K. Brown.[1]

second component represents the entire piping and artificial lift system. This includes separator, flowline, flowline restrictions such as chokes, tubing string, tubing string restrictions such as safety valves, and the artificial lift mechanism itself. Tubing intake pressures then can be determined for varying flow rates, and when this intake curve is placed on the same plot as the IPR curve, the rate for a particular lift method can be determined.

These factors should be considered in the selection of artificial lift equipment: producing characteristics, fluid properties, hole characteristics, long-range recovery plan, surface facilities, location, available power sources, operating problems, completion type, automation, operating personnel, service availability, and economics. Tables 1 and 2[1] summarize the advantages and the disadvantages of the principal methods that are commonly used.

Factors To Consider in Design

Liquid Productive Capacity of the Well

The desired rate from a particular well is the most significant factor in selecting the lift method. It is impor-

TABLE 2—RELATIVE DISADVANTAGES OF ARTIFICIAL LIFT SYSTEMS*

Rod Pumping	Hydraulic Pumping	Electric Submersible Pumping	Gas Lift	Hydraulic Jet Pumping	Plunger Lift
Crooked holes present a friction problem.	Power oil systems are a fire hazard.	Not applicable to multiple completions.	Lift gas is not always available.	Relatively inefficient lift method.	May not take well to depletion; hence, eventually requiring another lift method.
High solids production is troublesome.	Large oil inventory required in power oil system which detracts from profitability.	Only applicable with electric power.	Not efficient in lifting small fields or one well leases.	Requires at least 20% submergence to approach best lift efficiency.	Good for low-rate wells only normally less than 200 B/D (31.8 m/d).
Gassy wells usually lower volumetric efficiency.	High solids production is troublesome.	High voltages (1,000 V) are necessary.	Difficult to lift emulsions and viscous crudes.	Design of system is more complex.	Requires more engineering supervision to adjust properly.
Is depth limited, primarily due to rod capability.	Operating costs are sometimes higher.	Impractical in shallow, low-volume wells.	Not efficient for small fields or one-well leases if compression equipment is required.	Pump may cavitate under certain conditions.	Danger exists in plunger reaching too high a velocity and causing surface damage.
Obtrusive in urban locations.	Usually susceptible to gas interference—usually not vented.	Expensive to change equipment to match declining well capability.	Gas freezing and hydrate problems.	Very sensitive to any change in backpressure.	Communication between tubing and casing required for good operation unless used in conjunction with gas lift.
Heavy and bulky in offshore operations.	Vented installations are more expensive because of extra tubing required.	Cable causes problems in handling tubulars.	Problems with dirty surface lines.	The producing of free gas through the pump causes reduction in ability to handle liquids.	
Suseptible to paraffin problems.	Treating for scale below packer is difficult.	Cables deteriorate in high temperatures.	Some difficulty in analyzing properly without engineering supervision.	Power oil systems are fire hazard.	
Tubing cannot be internally coated for corrosion.	Not easy for field personnel to troubleshoot.	System is depth limited, 10,000 ft (3048.0 m), due to cable cost and inability to install enough power downhole (depends on casing size).	Cannot effectively produce deep wells to abandonment.	High surface power fluid pressures are required.	
H_2S limits depth at which a large volume pump can be set.	Difficult to obtain valid well tests in low volume wells.	Gas and solids production are troublesome.	Requires makeup gas in rotative systems.		
Limitation of downhole pump design in small diameter casing.	Requires two strings of tubing for some installations.	Not easily analyzable unless good engineering knowhow.	Casing must withstand lift pressure.		
	Problems in treating power water where used.	Lack of production rate flexibility.	Safety problem with high pressure gas.		
	Safety problem for high surface pressure power oil.	Casing size limitation.			
	Loss of power oil in surface equipment failure.	Cannot be set below fluid entry without a shroud to route fluid by the motor. Shroud also allows corrosion inhibitor to protect outside of motor.			
		More downtime when problems are encountered due to entire unit being downhole.			

*Reprinted with permission from S. Gibbs, Nabla Corp., Midland, TX, with modifications by K. Brown.[1]

tant to have sufficient data to construct pressure/flow rate diagrams, such as inflow performance curves shown in Fig. 1. This determination also is critical, depending on whether the objective flow rate is less that the maximum. An economic limit is reached when profits derived from increased oil production are offset by additional costs.

To compare rates of different lift methods properly, it is necessary to establish tubing intake curves for each lift system (Fig. 2). The solution position for rate determination in Fig. 2 is taken at the bottom of the well, opposite the completion interval. The intersection of each intake curve with the well inflow performance (IPR) curve shows the flow rate for a particular lift method. The rates possible by each method will change depending on well conditions. Each well must be evaluated separately, and many factors control the flow rate. For example, the rate by gas lift may exceed all other methods if relatively high volumes of free gas must be handled by the pumping mechanism, whereas electrical pumping may show higher rates for high productivity water wells and low GOR oil wells.

The procedures for preparation of these intake curves has been presented by Agena.[2] A short summary of the method of preparation is presented here. It is suggested that the first intake curve for any well will be prepared assuming that the well will flow naturally. Fig. 3 shows that this well does flow naturally. If the tubing intake curve falls above the IPR curve as noted in Fig. 3, the well is dead.

Procedure for Preparation of Tubing Intake Curves. The tubing intake curve is prepared independently of the IPR curve (see Figs. 4a, 4b, and 4c). To prepare these curves, all pressure losses must be accounted for starting from the separator and summing up all losses and gains (in case of pumps) to the bottom of the well. All restrictions such as surface chokes, safety valves, and downhole restrictions must be accounted for.

A brief description of the preparation of these curves is given in the following discussions and starts with the flowing well.

The Flowing Well. Fig. 5 shows the various losses in pressures and corresponding pressure traverses for a flowing well. For clarification, this is divided into surface and downhole segments.

For the simple system, the various restrictions such as surface chokes, etc. may be eliminated. Note that all losses are additive, beginning with the separator (constant pressure vs. rate for most applications). To construct tubing intake curves for a pressure vs. flow rate diagram, it is necessary to assume flow rates and to determine the corresponding tubing intake pressures. Typical results are shown in Fig. 4.

The solution node or position can be taken anywhere in the system. Often it is taken at the wellhead or the separator to emphasize the effect of certain segments of the system. Fig. 6 shows a wellhead pressure solution, which isolates the effect of the flowline. Fig. 7 shows the solution taken at the separator to emphasize the effect of separator pressure.

The separator pressure becomes increasingly important in rotative compressor gas-lift installations because

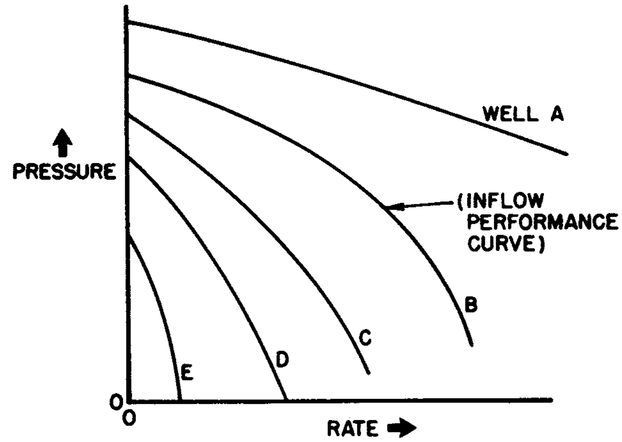

Fig. 1—Typical inflow performance curves.

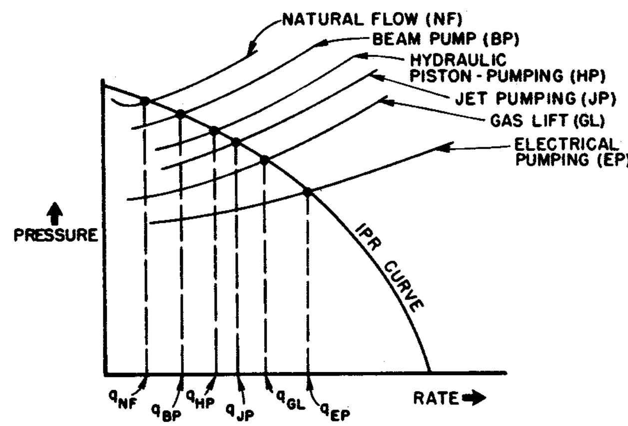

Fig. 2—Tubing intake curves for artificial lift systems.

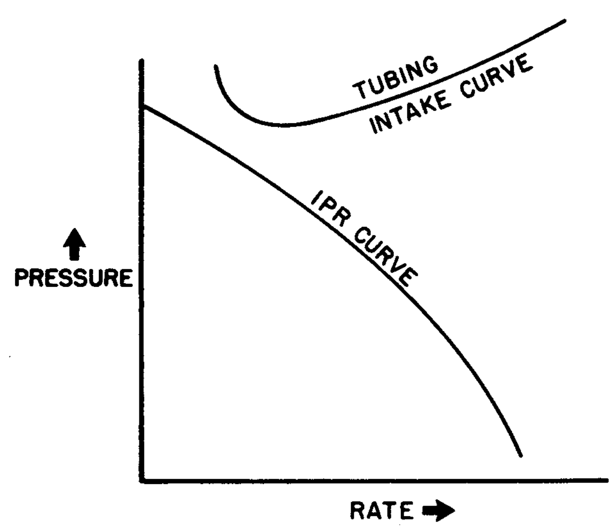

Fig. 3—Dead well.

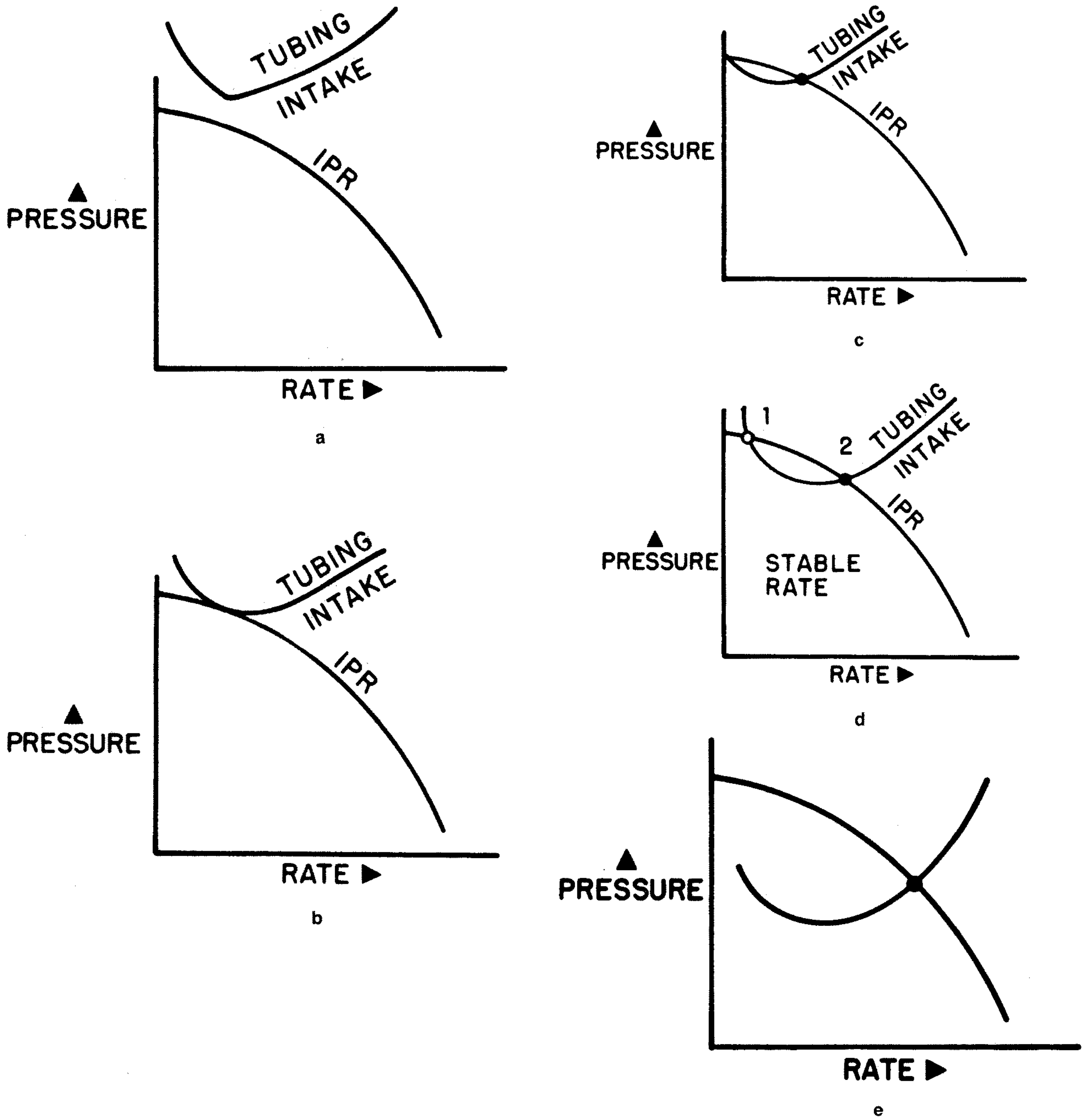

Fig. 4—(a) dead well, (b) dead well, (c) dead or severe heading well, (d) well flowing at Position 2, (3) stable flow.

the separator pressure controls the suction pressure to the compressor and, hence, controls horsepower requirements.

Gas-Lift Well. The preparation of tubing intake curves is more complex for gas-lift wells. This is because the injection gas/liquid ratio becomes an additional unknown quantity. Figs. 8 and 9 show typical continuous flow gas-lift system plots, including a horizontal flowline.

For gas-lift wells, the solution point to determine rate usually is taken at one of two nodes, at the bottom of the well or at the top of the well. Figs. 8 and 9 show the solution to the same problem taken at both nodes. If the solution point is taken at the bottom of the well, the well capability can be isolated. For IPR's at different average reservoir pressures, the node at the bottom of the well is a logical solution point. The tubing intake pressure curve represents the entire piping system, including separator pressure, flowline, any restrictions, and the tubing.

By taking the solution at the surface (Fig. 9), the piping system has been separated. One curve represents the separator pressure and flowline; the other curve incorporates the tubing string and IPR of the well. Both solutions may be advisable.

A final gas-lift well performance curve of oil flow rate vs. gas injection rate can be obtained from either plot. This final plot is essential for optimization (Fig. 10). For optimal allocation of gas to one well of a group, this type of curve is necessary.

Pumping Systems. The preparation of tubing intake curves for pumping systems can be relatively simple, for

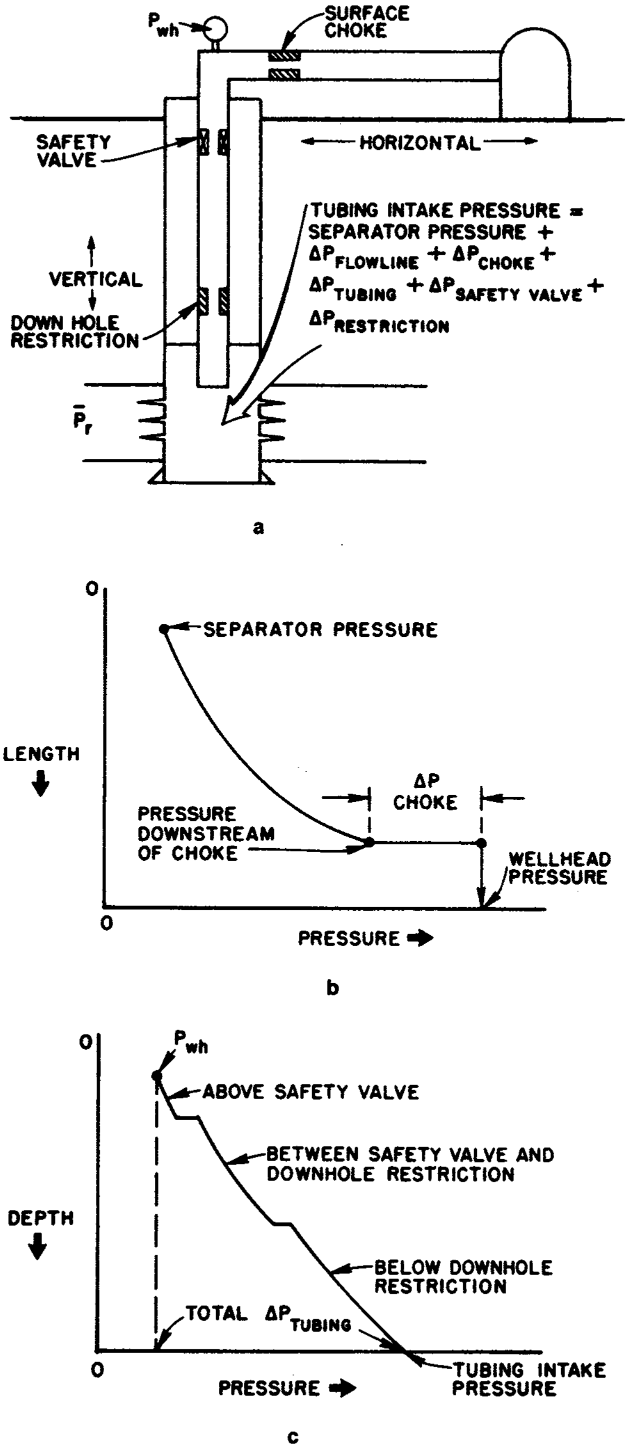

Fig. 5—(a) total piping system, (b) flowline pressure traverse, (c) tubing pressure traverse.

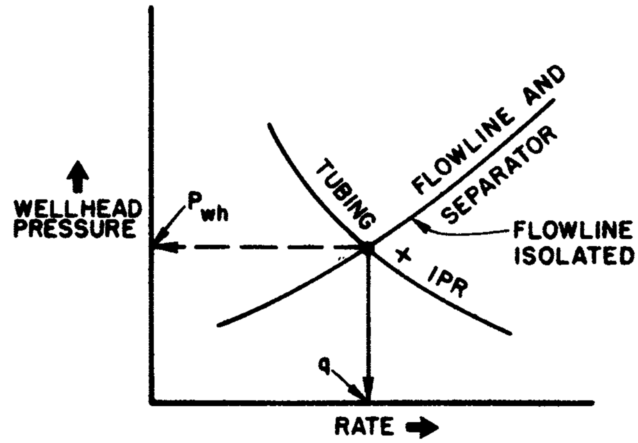

Fig. 6—Solution at wellhead.

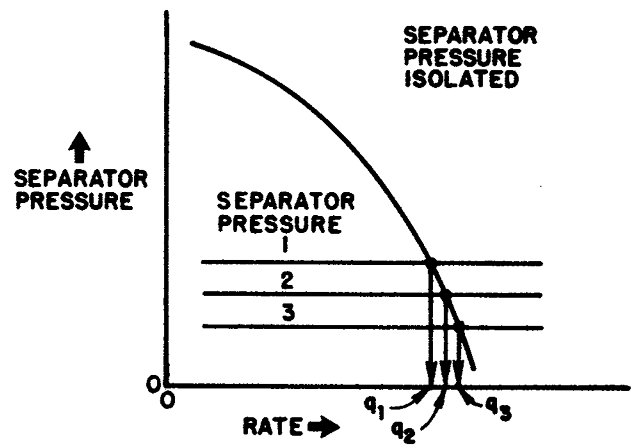

Fig. 7—Effect of separator pressure.

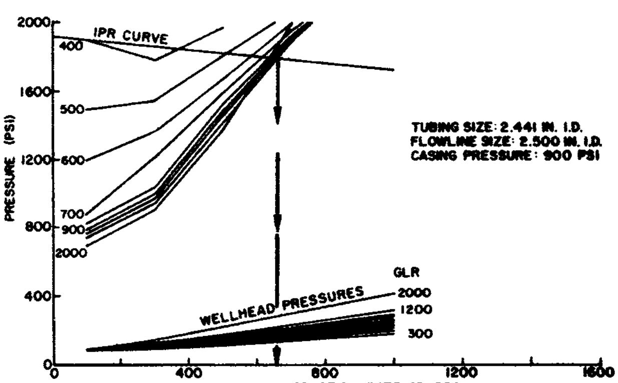

Fig. 8—Gas-lift solution node at bottom of well.

a well pumping no gas, to rather complex, for a well that must pump gas. The solution is easily understood by thinking of the pump as a downhole compressor that permits fluids to enter at one pressure and discharges them at another pressure. However, a pump is a very poor compressor when gas is present, and with liquids there is little or no compression, although a high Δp is developed. The problem becomes more complex when the pump is set up the hole compared with being set on bottom. A typical pressure traverse for a pumping system is shown in Fig. 11 along with the corresponding tubing intake curve. Note that the appearance of the tubing intake curve is the same as for gas lift or for the flowing well. A change in the pump size will shift the tubing intake curve.

For pumping systems handling gas, it is important to prepare IPR curves for total fluid intakes (Fig. 12).

Gas Production Expected From the Well

The amount of gas produced and, hence, the gas/liquid

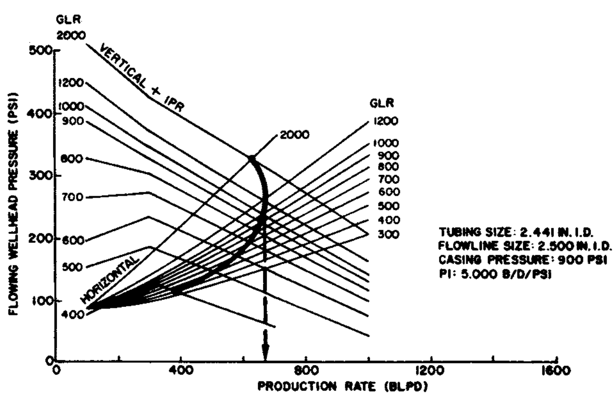

Fig. 9—Gas-lift solution node at top of well.

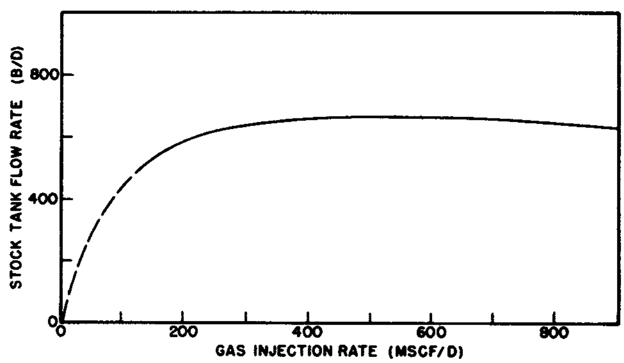

Fig. 10—Gas-lift performance curve for Figs. 8 and 9.

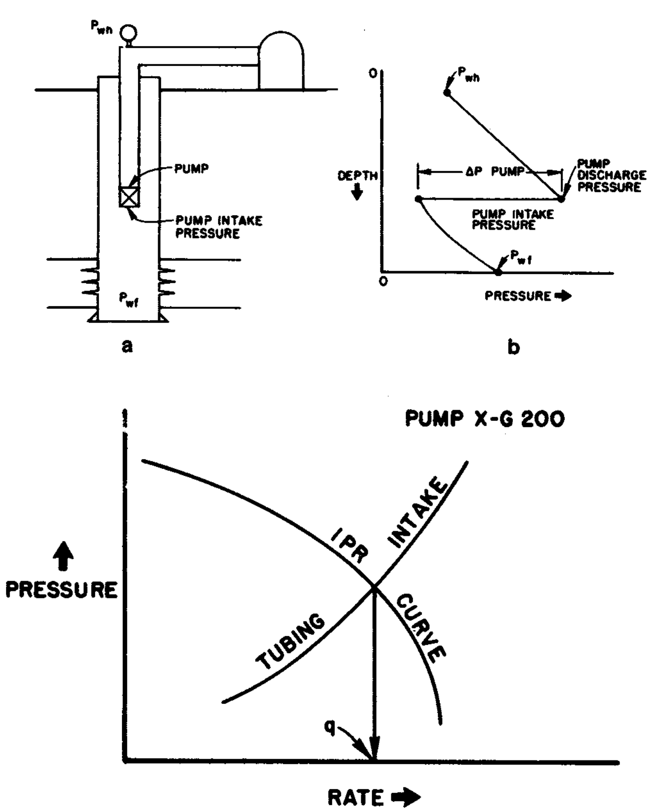

Fig. 11—(a) typical pump installation, (b) pressure traverse for pumping system, (c) pumping-system-rate solution at bottom of well.

ratio is a significant factor in selecting the artificial lift method. If high volumes of gas must pass through the lift mechanism (Fig. 12), a reduction in liquid capacity can be expected for all pumping systems, and gas lift is one of the most logical choices. Complete gas-lock may occur in some pumping systems, but in any event the gas occupies volume that must be displaced. The ability of some pumping systems to handle gas is suspect. Electrical pumps start losing efficiency when the in-situ gas volume to be handled exceeds 10% of the total fluid pumped. Sucker rod pumps may gas-lock completely with high gas production. Hydraulic piston pumps should not gas-lock, but they must displace the gas and, hence, liquid capacity is reduced. Therefore, hydraulic piston pumps are affected less seriously by gas than are rod pumps. The difficulty of venting gas in offshore locations (beneath the safety valve) can reduce the pump's effectiveness. Free gas also reduces the ability of jet pumps to handle liquids. Gas lift and plunger lift are suitable for high GOR wells.

The physical limitations of gas venting must be reviewed thoroughly. Current practices do not encourage wasting any energy, and, therefore, the gas must be placed back in the same system as the well production, or provision must be made for a separate system. In some fields a low-pressure gas pickup system may be installed, and the venting of gas into a lower-pressure system may be much more attractive.

A few artificial lift systems are ideally suited for handling gas, such as continuous flow gas lift, intermittent gas lift, and plunger lift. Continuous flow gas lift can be benefited if the formation produced gas is not already excessive—i.e., if the injection of additional gas still can lighten the flowing pressure gradient. Intermittent gas lift can lift wells making gas but does not utilize the formation gas in doing so. A plunger may be ideally suited for wells making gas, but provision must be made for communication between the tubing and annular space in most cases. The volume and pressure buildup on the casing provides the necessary energy to push the plunger to the surface periodically.

Depth Limitations and Effective Lift

An often misunderstood term is "effective lift." For example, a pump may be set at 12,000 ft (3657.6 m) but only lifts from 8,000 ft (2438.4 m). Therefore, if we

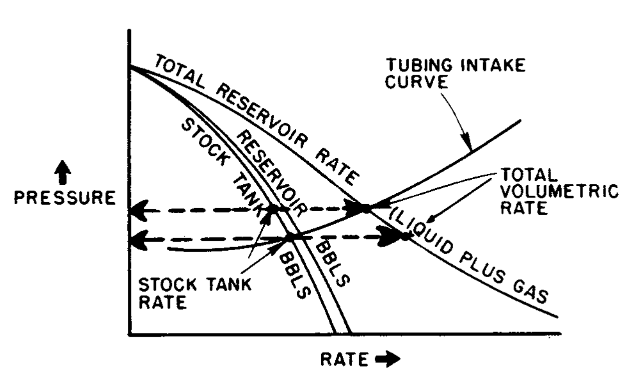

Fig. 12—IPR curves for total fluid production including gas.

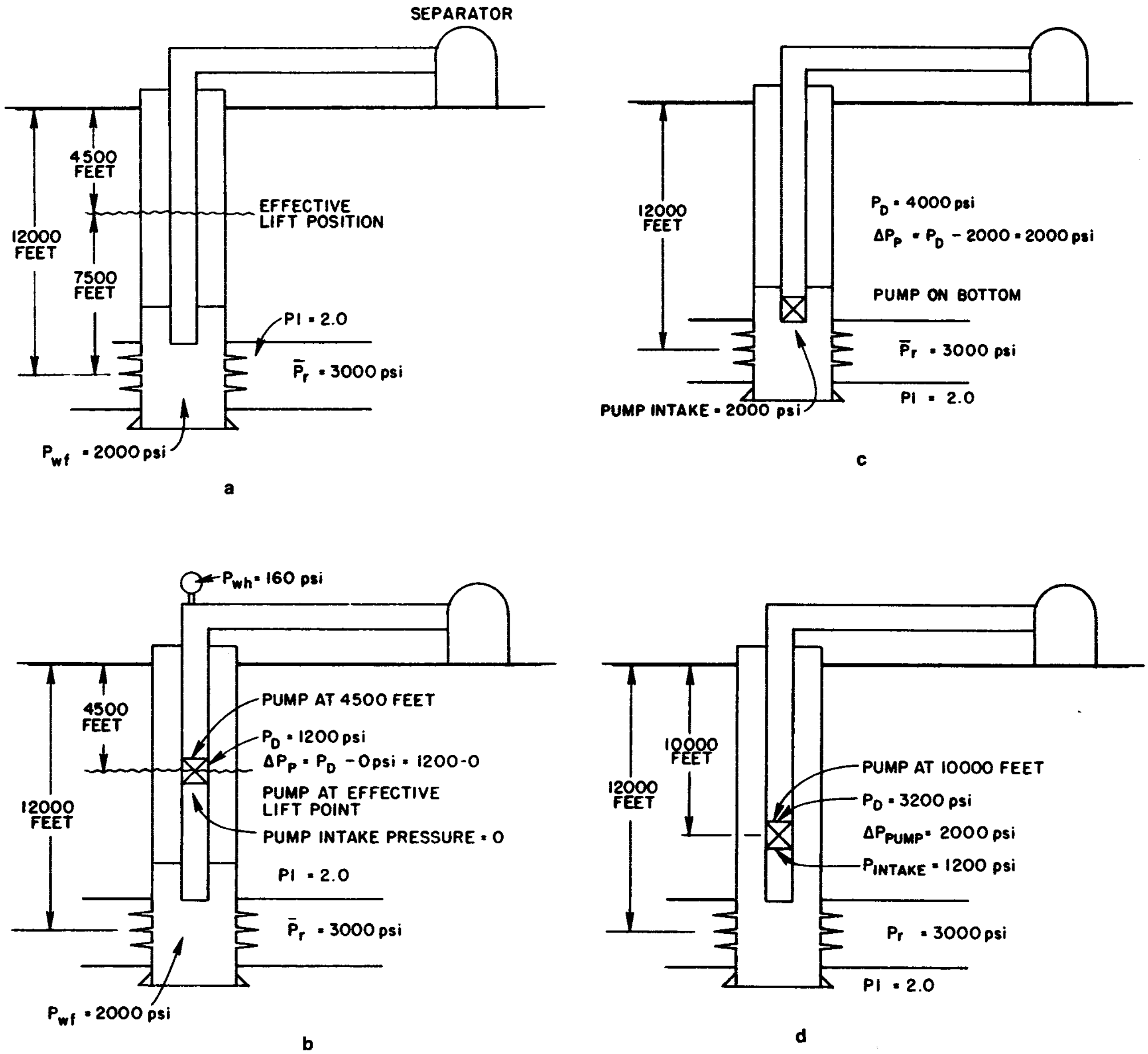

Fig. 13—(a) effective lift piston, (b) pump set at effective lift, (c) pump set at bottom, (d) pump set at 10,000 ft.

assume that the pump must lift from its setting depth, the unit may be designed for greater horsepower than required. For example, if a well is 12,000 ft (3657.6 m) deep, has a static pressure of 3,000 psi (20.68 MPa), PI is 2 (assumed constant), gas liquid ratio=300 scf/bbl (53.5 std m_3/m_3), wellhead pressure is 160 psi (1.10 MPa), and is completed with 2½-in. (6.35-cm) tubing, what is the depth of effective lift for a rate of 2,000 B/D (317.97 m^3/d)? The flowing bottomhole pressure (BHP) required for the well to yield this rate is $3{,}000-(2{,}000/2)=$ 2,000 psi (13.79 MPa). The effective lift point is that depth to which the flowing BHP is capable of supporting the fluids in the tubing string. The appropriate multiphase flow correlation shows this to be 7,500 ft (2286 m) from bottom or at a depth of 4,500 ft (1371.6 m) (Fig. 13). Theoretically, a pumping system could be set at 4,500 ft (1371.6 m) and, by creating a zero intake pressure at this point, the objective flow rate could be obtained. The discharge head above the pump then would consist of all head and pressure losses above 4,500 ft (1371.6 m), such as tubing loss, flowline loss, and separator pressure.

If we assume that the pumping system is at 10,000 ft (3048 m), or even on bottom at 12,000 ft (3657.6 m), the pump must lift only from the effective lift point of 4,500 ft (1371.6 m). Another way to visualize this concept is to note that the pump must create a certain discharge pressure to overcome all pressure losses and head above the effective lift point, which is also the Δp that the pump must create if it is set at the effective lift point. In the previous example, this Δp is 1,200 psi (8.27 MPa) and is approximately the same regardless of the pump position, neglecting any effect of changes caused by multiphase flow calculations. Fig. 13 clarifies this with the pump set at different positions. Note that discharge pressure is the same if the pump is on the bottom or at 10,000 ft (3048 m), but less at 4,500 ft (1371.6 m) because of free gas lightening the pressure traverse. However, the total fluid volume (oil plus free gas) is much higher at 4,500 ft (1371.6 m).

There are many reasons for setting a pump either below or near the effective lift point. Obviously, the pump should be submerged enough to allow sufficiently high entry pressure to prevent cavitation and to overcome any entry loss restrictions that might exist across a downhole gas separator. Submergence in feet (meters) is defined as the fluid level in the annulus above the pump under operating conditions. The desirability of creating low pump intake pressures may restrict some pumping systems, and a general rule of thumb of 300-psi (2.07-MPa) pump intake pressure for oil wells pumping gas will restrict some pumps. The handling of free gas volumes through the pump makes the deeper setting position more attractive.

Depth Limitations. *Electrical Pump.* The principal depth limitation for electrical pumps in past years has been excessive temperatures. This limitation has been improved upon, with some units now operating at 350°F (176.6°C). However, shorter motor and cable life can be expected as the temperature increases. Deeper setting depths may be desirable to eliminate pumping free gas, but longer life is expected for temperatures less than 225°F (107.2°C).

Gas Lift. Gas lift is limited in depth principally by the availability of gas injection pressure, with wells now operating with surface injection pressures of from 300 to 3,000 psi (2.07 to 20.68 MPa). However, most gas-lift valves begin to show shortened life expectancy at pressures above 1,500 psi (10.34 MPa), and operational characteristics of the valve may be less than optimum because of very high dome charges or very strong and heavy springs. However, some gas-lift valves are being operated successfully at surface pressures of 2,500 psi (17.24 MPa) or greater. For continuous flow, injection depths of below 12,000 ft (3647.6 m) have been achieved. However, most of the very high-pressure operations are utilizing orifices at the operating point.

Intermittent slug flow has been used to 12,000 ft (3657.6 m), but the fallback of liquids can consume most of the original starting slug. When used in conjunction with a plunger, much of the slippage can be eliminated. Intermittent chamber lift becomes more effective from greater depths.

Jet Pump. The jet pump is not very efficient for lifting from great depths. It also requires a higher percentage of submergence than do the other lift systems. A minimum of 20% submergence is needed for most applications and even greater for better efficiencies. However, some jet pumps are set at 11,000 ft (3352.8 m) and are producing 200 to 300 B/D (31.8 to 47.7 m^3/d).

Hydraulic Piston Pumping. The most successful method of artificial lift for wells below 10,000 to 12,000 ft (3048.0 to 3657.6 m) has been hydraulic piston pumping. In south Louisiana, several pumps have been set below 12,000 ft (3657.6 m) with a few at 15,000 ft (4572 m) and 18,000 ft (5486.4 m). They are handling 300 to 500 B/D (47.7 to 79.5 m^3/d), although the exact depth of effective lift was not specified. Additional details can be found in Ref. 2. Because of abnormal sand production in these areas, the free pumps are replaced periodically on a scheduled basis. The ability to replace this pump with very little downtime makes it attractive for these conditions. Care should be exercised and deep well installations should be limited to low PI and low BHP.

Beam Pumping. Some beam pumping systems are operating below 12,000 ft (3657.6 m); however, the additional horsepower to lift the sucker rods may become excessive, and work to lift the rods must occur from the pump depth and not from the effective lift depth. Very low flow rates are expected.

The beam pump is the most widely used system for shallow and medium-depth wells. The large number of wells on beam pump shows its attractiveness, and most operators feel quite comfortable with the beam unit and it is an important factor in selection of lift equipment.

Special units can pump more successively from depths below 10,000 ft (3048 m).

Plunger Lift. The plunger has no real depth limitation, but sufficient pressure must be obtained in the casing to remove the plunger. The installation may be supplemented with injection gas. Several are installed below 11,000 ft (3352.8 m).

Flexibility. Flexibility of lift methods to change their rate as well producing characteristics change is an important factor. The original objective rate for which the artificial lift system was designed may change because of (1) decreased well productivity caused by lowering the static BHP and/or inflow ability; (2) increased well productivity resulting from secondary or tertiary recovery methods, causing increased static pressure and/or well inflow ability; (3) errors that exist in original well data or in multiphase flow correlations; and (4) a change in the objective flow rate from sand production, coning, competitive well, or conservation practices.

Gas Lift. Gas lift offers a wide range of flexibility within the rate ranges it is capable of producing. It can handle thousands of barrels down to a few barrels per day. To account for this in the original design, more gas-lift valves than necessary may need to be installed to produce the original objective rate. Also, gas-lift valve changes are necessary if a change is to be made from continuous to intermittent flow.

Beam Pump and Hydraulic Pump. For those pumping systems where a change in strokes per minute or stroke length is accomplished easily, flexibility in rate is obtained easily within the specified rate limitations.

Electrical Pump. Until the recent development of the variable-frequency controller, the electrical pump was the least flexible of the lift systems operating within a specified speed and power frequency, such as 3,500 rpm (366 rad/s) at 60-cycle power and 2,915 rpm (305 rad/s) at 50-cycle power. The variable-power frequency unit has increased the flexibility of this pump over a much wider range. The frequency controller is effective only in reducing the rate downward. It does not develop additional horsepower in the motor. Therefore, the motor must be overdesigned or designed for the maximum possible condition so it can be slowed down to bring the pump into a more efficient range.

The jet pump is quite sensitive to change in rates, and care should be exercised to size it reasonably close to the desired rates. It is also very sensitive to backpressure and requires more submergence than other systems.

The plunger lift and intermittent gas lift both are limited as to the number of cycles possible per day. Plungers are now in service that travel from 11,000 ft (3352.8 m) in 12 to 15 minutes. Intermittent gas lift and plunger lift are flexible in setting rates lower than the upper limit of about 200 B/D (31.8 m^3/d). Some exceptions have occurred in chamber gas lift, with rates of 500 to 600 B/D (79.49 to 95.39 m^3/d). These rates were achieved in low static pressure, high productivity wells. Adjustments downward from the maximum offer no problem.

Surface Location. Location becomes critical with some systems. The beam pump normally is not considered for offshore platforms, although there are many units in shallow inland waters, such as Lake Maracaibo of Venezuela.

A new innovation of the sucker rod pump (Fig. 14) has been considered in a few areas offshore Africa. This system utilizes a winch-type principle, a means of pulling its own sucker rods, and occupies very little space.

Gas lift, electrical pumping, and hydraulic piston pumping are the systems generally considered for offshore operations. The ability to retrieve gas lift valves and hydraulic pumping units is a distinct advantage, with the hydraulic pump having the lowest upper volume limitation. The use of power water eliminates the fire hazard of the hydraulic system. The electrical pump currently is not considered developed sufficiently for retrievable operations, although a few are installed. If and when the retrievable problems are removed, the electrical pump will be one of the most attractive lift methods for offshore.

The location of the system in urban areas requires proper environmental considerations. Sometimes the distant location of the power system, such as a compressor for gas lift or surface facilities for a hydraulic pump, becomes attractive. Special considerations also are needed for extremely cold and hot climates.

Heavy Crude Oils. The lifting of more and more heavy crude oils is becoming necessary. Currently most are handled with the beam pump. The hydraulic pump offers a ready means of mixing a light power oil with a heavy producing crude to reduce the viscosity. The economics and practicability of this solution are questionable. A light crude must be available, and there is a reduction in quality and price in the mixing.

Special types of lift have been devised to lift heavy crudes, such as the Efflar unit.[2] The efficiency of the electrical pump is reduced considerably and gas lift does not appear very attractive. The beam pump, therefore, is used more extensively than are other methods.

Lifting heavy crudes in fields by use of steam floods requires special attention to very hot fluids.

Operating Problems. Operating problems are difficult for some lift methods and include sand, paraffin, scale, corrosion, emulsions, downhole temperature, and surface climate.

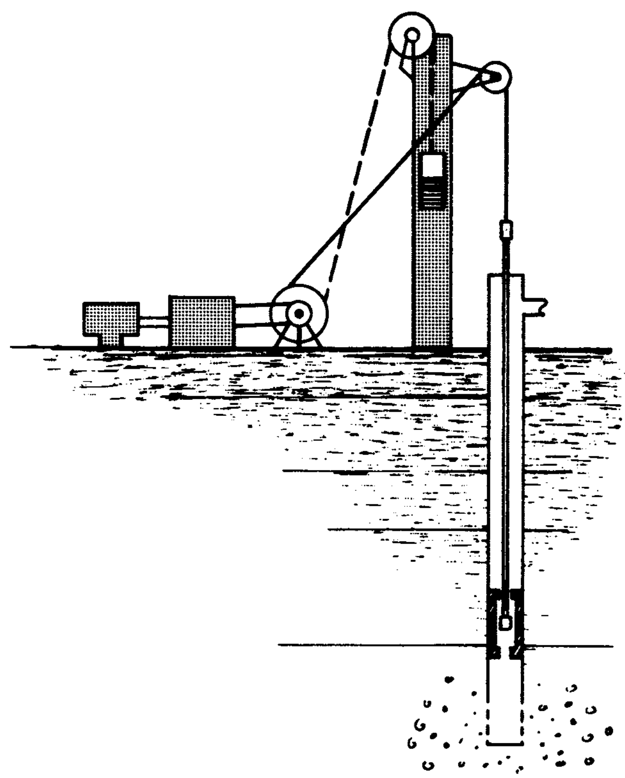

Fig. 14—Long stroke pumping unit.

Sand. Production of sand causes erosion problems for all types of artificial lift. Gas lift is the only method that does not require that the sand-laden fluid pass through the lifting mechanism. Sand fillup on top of a bottomhole pump may cause retrieval problems.

Paraffin. Accumulation of paraffin in the upper portions of the tubing string, wellhead, or flowline will cause backpressure that reduces efficiency. Removal or prevention is required. Sucker rod pumping has an advantage over other lift methods since the rods provide continuous scraping action. Scrapers or guides may aid paraffin removal. High-temperature fluids and inhibitors can be circulated immediately in a hydraulic system. Plungers serve as automatic paraffin scrapers.

Scale. Deposition of scale will reduce the ID of tubing and therefore will decrease efficiency. Gas lift may aggravate scale deposition. Prevention by chemical additives may provide longer pump life and may maintain fullbore tubing. Plungers will keep the tubing clean.

Corrosion. Downhole corrosion may be caused by electrolysis between different metal types, H_2S, or CO_2 content in the produced fluid, highly saline or saturated brine water, or oxygenation of metals. H_2S embrittlement is a major problem and will accelerate sucker rod failure if the rods are excessively loaded. Gas lifting with corrosive gas may prove uneconomical. However, current thinking in the industry seems to indicate that in most cases gas lift with corrosive gas creates no

TABLE 3—GIVEN DATA, EXAMPLE 1*

Depth, ft (m)	8,000 (2438.4)
GOR, scf (std m^3/m^3)	400 (71.3)
Water production, %	50
Rate, B/D (m^3/d)	800 (127.19)
°API	42
Tubing size, in. (cm) OD	2⅞ (7.31)
All power sources available	
$\bar{p}_R$, psia (MPa)	2,300 (15.86)
PI until reaching p_b = 1,600 psi (11.03 MPa)	3
p_{wh}, psia (MPa)	100 (0.69)
Casing size, in. (cm)	7 (17.79)

*Reprinted with permission from S. Gibbs, Nabla Corp., Midland, TX, with modifications by K. Brown.[1]

particular problem if the injection gas is dehydrated properly.

Emulsions. Anticipating emulsion problems when planning and selecting artificial lift methods is difficult. Emulsions cause abnormally high pressure losses in the tubing.

BHT. Very high BHT's will reduce the operating life of some types of lift equipment. The electrical submersible pump motor and cable are affected. Precautions must be taken when the temperature exceeds 200°F (93°C). High-cost metallurgy and seals are required in all equipment, including packers, tubing, wellhead equipment, and downhole lift equipment.

Surface Climate. Extremes in surface climatic conditions may influence the selection of lift equiment. Very hot climates cause overheating problems with surface equipment, and special cooling facilities must be provided. Very cold climates cause freezing problems for fuels and embrittlement of electrical connections; insulation and heating must be provided. Also, many areas experience high winds that cause surface damage, and dust or snow may cause operational problems.

Operating Personnel. Technical ability of the operating field personnel may influence artificial lift selections. Sucker rod pumping may offer less troublesome operation for field personnel than will other types of lift. Engineering supervision may be required for gas lift, with special operating instructions required for hydraulic, electric submersible pumping, jet pumping, and plunger lift.

Services Available. One of the important factors in selection of an artificial lift method is the availability of competent service personnel, replacement parts, and service rigs or equipment. In some areas, the choice of a less desirable type of lift has been made solely on the availability of service personnel. Replacement parts availability is equally as important as service personnel. If lift equipment cannot be serviced and repaired readily, an alternate lift method may be chosen.

Some types of lift require pulling tubing (or rods) and pump for service and replacement, while others can be serviced by wireline. Hydraulic pumps may be circulated to the surface without requiring a rig or a wireline unit.

Relative Economics. Six economic factors represent the most important parameters in selection of artificial lift equipment: (1) initial capital investment, (2) monthly operating expense/income cost indicators, (3) equipment life, (4) number of wells to be lifted, (5) surplus equipment availability, and (6) well life.

Each of the artificial lift systems has economic and operating limitations that eliminate it from consideration under certain operating conditions.

Economic and operating guidelines are fairly well defined by experience, especially within a given set of well-defined operating conditions. Space does not permit a complete economic comparison in this paper.

Example Problems

The problem in Table 3 was given by Brown *et al.*[1] to illustrate several choices for artificial lift system. For these problems, the best type of lift is to be selected. The information in the general problem is used, and changes are made in each example to alter the possible lift choice with all else remaining constant.

Example 1

1. Gas/liquid ratio=3,000 scf/bbl (540 std m^3/m^3), PI=0.01, and liquid flow rate=20 B/D (3.10 m^3/d). The first choice should be intermittent gas lift or plunger lift. Beam pumping or hydraulic pumping may be considered if proper gas venting can be accomplished. Sufficient gas is available to run a plunger.

2. Depth=12,000 ft (3657.6 m), PI=0.1, and liquid flow rate=200 B/D (31.80 m^3/d). The hydraulic piston with venting should be considered because of the great depth.

3. Rate=6,000 B/D (953.92 m^3/d), PI=10, and the tubing is 4 in. (10.16 cm). The choice would be continuous flow gas lift or electrical pump. Since 6,000 B/D (953.92 m^3/d) with a PI of 10 requires a flowing pressure of only 1,700 psi (11.72 MPa), it is still above the bubble point, and no free gas is pumped if the pump is set on bottom. Setting the pump higher up in the hole would induce gas liberation, and a means of venting would be required. Jet pumping also may be considered.

4. Severe H_2S problem. If the lift gas can be kept free of H_2S, continuous-flow gas lift would be a good choice. However, Monel or some other noncorrosive material shoud be used. Gas lift is the only lift method where the well fluids do not pass through the lift mechanism. Electrical submersible and hydraulic may be considered.

5. Depth=3,000 ft (914.4 m), rate=400 B/D (63.59 m^3/d), $\bar{p}_R$=1,200 psia (8.27 MPa), and PI=1.0. This is a good choice for beam pumping because of the shallow depth and the rate of 400 B/D (63.59 m^3/d).

6. No engineering supervision is available. Beam pumping is the method best understood by most field operators, with continuous-flow gas lift also a good choice.

7. Well produces sand. With great sand production, the choice would be continuous-flow gas lift.

8. Bad paraffin problems. All methods can be considered, but paraffin removal must be kept in mind. Rod pumping is probably the best choice. Some operators have found that in higher rate wells the flowing well

temperatures can be kept high enough to eliminate paraffin forming downhole. This can be an important factor in tubing selection for gas lift. Some people actually accelerate paraffin formation by making allowances for ID reductions in the tubing as a result of paraffin formation. Some operators have found that paraffin scrapers increase friction and load in a pumping well and that treatment with a chemical or hot oil will be required. Rod pump should not be chosen on the basis of ease of paraffin removal alone. It might be easier to design around the paraffin by increasing the velocity in a gas lift or submergible electric pump well.

9. Depth=6,000 ft (1828.8 m), rate=10,000 B/D (1589.87 m^3/d), 2⅞- ×7-in. (7.30- ×17.78-cm) annular flow, and PI=15. Continuous-flow gas lift is a good choice, with electrical submersible and jet pump as alternatives.

10. Rate=25,000 B/D (3974.68 m^3/d), choice of annular or tubing flow, 9⅝-in. (24.45-cm) casing, 4-in. (10.16-cm) tubing, and PI=25. Continuous-flow gas lift or electrical submersible pump should be chosen.

11. $\bar{p}_R$ drops to 300 psi (2.07 MPa), PI=0.02, and rate is the maximum possible. Beam pumping or hydraulic pumping are the best choices.

12. $\bar{p}_R$ drops to 100 psi (0.69 MPa), PI=0.01, and rate is the maximum possible. Beam pumping or hydraulic pumping again are the best choices.

13. One-hundred percent oil, GOR=4,000 scf/bbl (720 std m^3/m^3), $\bar{p}_R$=500 psia (3.45 MPa), PI=0.02, and rate is the maximum possible. Plunger lift, because of the high GOR, or beam pumping with adequate venting are the two best methods.

14. Long 300-ft (91.44-m) perforated interval, $\bar{p}_R$=500 psia (3.45 MPa), PI=2, and rate is the maximum possible. This is a good candidate for chamber intermittent gas lift.

15. Openhole completion [400 ft (121.92 m)], $\bar{p}_R$=700 psia (4.83 MPa), PI=1.0, and rate is the maximum possible. This is a good candidate for an insert-type chamber intermittent gas lift.

Example 2

Offshore Well. Depth is 8,000 ft (2438.4 m). There is high productivity, high static pressure, low solution GOR [100 scf/bbl (18 std m^3/m^3)], with bubble point at 250 psi (1.7 MPa). Desired rate of 10,000 B/D (1589.87 m^3/d) can be obtained with a flowing pressure of 1,500 psi (10.34 MPa).

Selection Choice. Electrical submersible pump is the best method because no free gas will be pumped and a rate of 10,000 B/D (1589.87 m^3/d) can be obtained only with continuous-flow gas lift or electrical pump. The very low GOR makes the electrical pump more attractive. Gas lift runs a close first choice because of better retrieving reliability. More realistic selections should be made by changing flow conduit sizes for each system. Most operators still would prefer gas lift offshore if sufficient gas is present in the crude because of the lower operating and maintenance cost and much greater operating reliability. Note that gas lift well availability (days on production) historically runs between 90 and 95%, whereas submergible electric pumping may run as low as 75% (depending on rig and equipment availability when pulling is required). This means that to produce an average annual rate of 10,000 B/D (1589.87 m^3/d) from a given well, gas-lift equipment should be designed to produce about 11,000 B/D (1748.85 m^3/d) and submergible electric pumping should be designed for about 13,000 B/D (2065.7 m^3/d). This sometimes means that more wells will be required to produce a field by pump than by gas lift.

Same Offshore Well. However, for this problem, consider a GOR of 800 scf/bbl (144 std m^3/m^3), with a bubble point of 1,500 psi (10.34 MPa).

Selection Choice. Continuous-flow gas lift is a better choice since free gas exists at the required flowing BHP. Because it is an offshore well, the retrievable equipment is again very attractive, and because the electrical pump will need to handle some gas, the pump's liquid handling capability is reduced.

Example 3

Land Well. Depth=8,000 ft (2438.4 m), static pressure=1,920 psi (13.24 MPa), PI=5, bubble-point pressure=1,000 psi (10.34 MPa), GOR=200 scf/bbl (36 std m^3/m^3), well produces 50% water, tubing is 2⅞-in. OD×2.441-in. ID (7.30-cm OD×6.20-cm ID) and casing is 7 in. (17.78 cm). This well was analyzed for rates possible, and was found to produce as follows.

1. Electrical submersible pump, 4,500 B/D (715.44 m^3/d). (Handles no free gas at this rate.)
2. Continuous-flow gas lift with a surface injection pressure of 1,500 psi (10.34 MPa), 1,750 B/D (278.23 m^3/d). [Tubing of 4½ in. (11.4 cm) would handle 4,000 B/D (635 m^3/d).]
3. Beam pumping with a 640 unit, 1,750 B/D (278.23 m^3/d).
4. Hydraulic pumping with a large pump, 1,750 B/D (278.23 m^3/d).
5. Jet pumping (handling no free gas), 2,750 B/D (437.22 m^3/d).

It also was noted that approximately 4,000 B/D (635.95 m^3/d) could be made by continuous-flow gas lift if a change was made to 4½-in. (11.43-cm) OD tubing. Lower increases were noted for all pumping systems, although less horsepower is required for the larger tubing size. Final selection would depend on the objective flow rate (whether maximum or less) and economics.

Example 4

1. $\bar{p}_R$=1,500 psi (10.34 MPa), depth=7,600 ft (2316.48 m), bubble-point pressure=1,500 psi (10.34 MPa), maximum flow rate for zero flowing BHP is 215 B/D (34.18 m^3/d), and GOR=400 scf/bbl (71.3 std m^3/m^3).

This well was analyzed for rate, with these results: (1) beam pumping, 200 B/D (31.80 m^3/d), (2) hydraulic pumping, 200 B/D (31.80 m^3/d), (3) jet pumping, 165 B/D (26.23 m^3/d), (4) continuous-flow gas lift, 165 B/D (26.23 m^3/d), (5) intermittent-flow gas lift with a chamber installation, 190 B/D (30.21 m^3/d), and (6) electrical submersible pumping, 200 B/D (31.80 m^3/d).

The logical choice for this well is beam pumping, or hydraulic pumping if adequate venting can be accomplished. The electrical pump requires too many stages to handle the gas, and it loses efficiency.

If gas venting cannot be handled properly, a chamber intermittent gas-lift installation would be a good selection. The option of running a plunger in conjunction with a chamber would be another choice and should increase efficiency.

Conclusions

The selection of an artificial lift method should be considered very carefully. Tables 1 and 2 list the respective advantages and disadvantages, and each should be evaluated. The main criterion is rate, and this should be foremost in selection. Other factors, such as handling gas, location, and economics, are very important.

1. Sucker rod pumping is the most widely used type of lift system. Historically, the main advantage has been the familiarity of this type of lift to operating personnel. One of the main disadvantages has been depth limitation. However, larger load capacity units and high-strength rods allow greater depths [12,000 ft (3657.6 m)].

2. Gas lift compares favorably with hydraulic pumping in providing the most flexible depth and rate range of all lift types. Gas lift also may be used to kick off wells that flow naturally, to backflow water injection wells, and to unload liquids from gas wells. The retrievability of valves by wireline makes it very attractive anywhere expensive tubing jobs can be expected.

3. Hydraulic pumping may not be limited to depth, with production from 18,000 ft (5486.4 m) as an example. Hydraulic pumps can be run with vent strings and gas anchors to handle GOR's up to about 4,000 scf/bbl (720 std m^3/m^3), depending on productivity. Sufficient casing size must be available for tubing and vent, plus annular space for return fluids. In deeper wells this can lead to higher surface pressures which, in turn, can limit production to high-BHP wells.

4. The electrical submersible pump historically has been associated with high-volume fluid production, but variable-frequency controllers have changed this. Another unique use of this pump has been in increasing the volume of dumped water from formations above to a waterflood formation below. The pump can be run on a cable and landed in a nipple in a standard well to induce flow, and then can be removed later when the well flows naturally. The horsepower limit is set by the shaft size that can be installed in small-OD housings. A submersible pump should never be set below fluid entry unless a jacket is used to direct fluid by the motor.

5. Jet pumping offers downhole equipment with no working parts. The full limitations are not yet known, but some are installed below 11,000 ft (3352.8 m) making 200 B/D (31.80 m^3/d), with others producing 25,000 B/D (3974.68 m^3/d) from shallow depths. High-pressure equipment, power fluid lines, and wellheads are required. Facilities must be provided to filter, to clean, and to treat the fluid.

6. A plunger may be used to maintain flowing status of a well but is normally temporary and usually is replaced when a method of lift is chosen. High-GOR and low-volume wells can be ideal for a plunger.

7. Numerous other methods of lift are available and may fulfill the needs for a particular well. They should be considered where applicable.

8. Special attention must be paid to service and repair, and availability of parts and exchange equipment. A good artificial lift method can be selected by carefully considering all aspects of installation, design, availability, and service.

References

1. Brown, K.E., *et al.*: *The Technology of Artificial Lift Methods*, PennWell Books, Tulsa (1979) **II-B.**
2. Agena, B., "Preparation of Tubing Intake Curves for Artificial Lift Systems," MS thesis, U. of Tulsa (1982).

SI Metric Conversion Factors

bbl	× 1.589 873	E−01	= m^3
ft	× 3.048*	E−01	= m
in.	× 2.54*	E+00	= cm
psi	× 6.894 757	E−03	= MPa

*Conversion factor is exact.

JPT

Original manuscript received in Society of Petroleum Engineers office July 20, 1981. Paper accepted for publication May 11, 1982. Revised manuscript received July 30, 1982. Paper (SPE 9979) first presented at the 1982 SPE International Petroleum Exhibition and Technical Symposium held in Beijing, March 18–26.