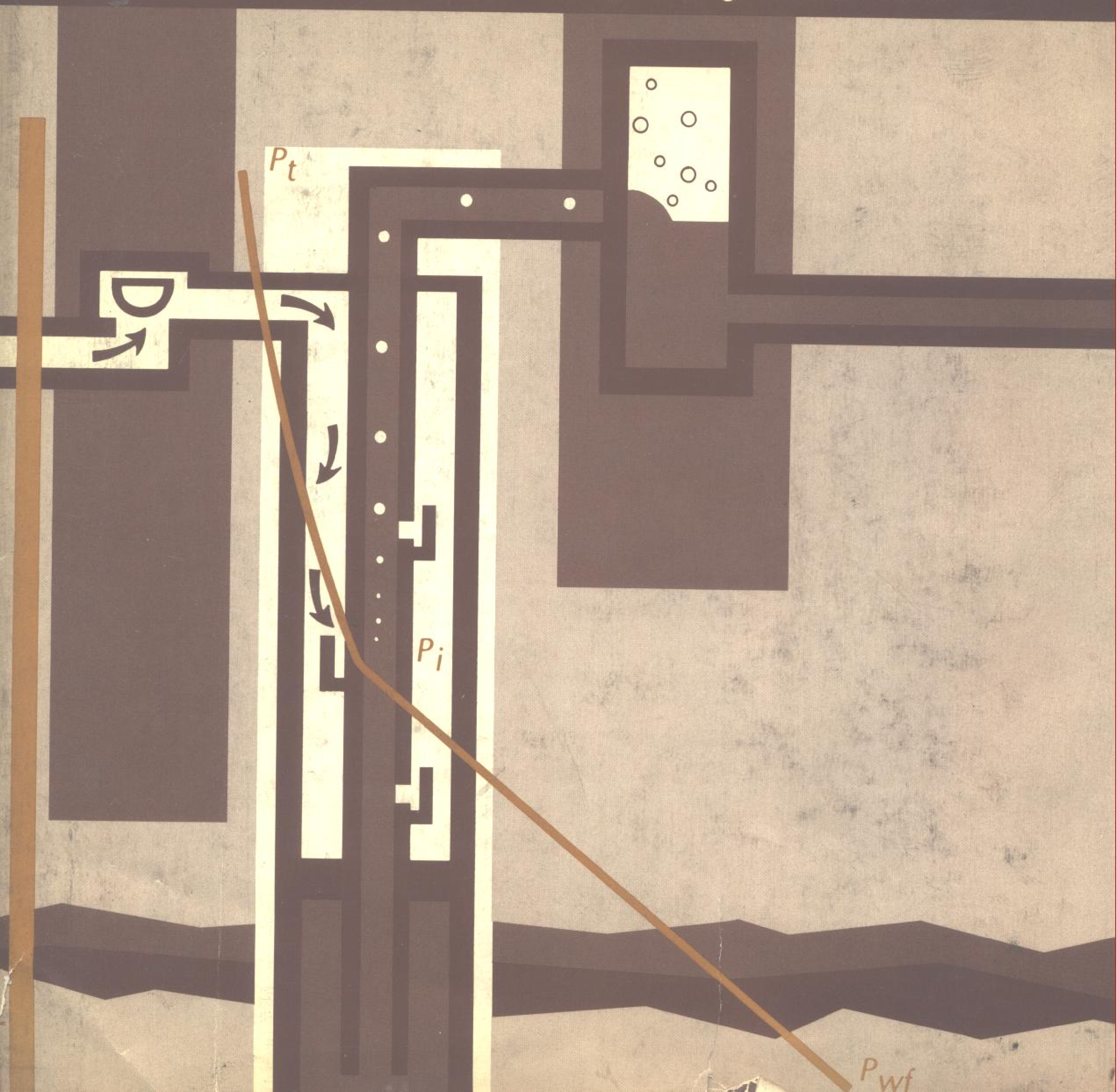
Kermit E. Brown

A comprehensive review for petroleum engineers of conversions and dimensional analysis, reservoir mechanics, and curve fitting, used as introductory material to a complete presentation of the theory and application of gas lift and multiphase flow, including gas lift installation design

Gas Lift Theory and Practice

Including a Review of Petroleum Engineering Fundamentals



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Gas Lift
Theory and Practice

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Dedicated to

Katherine, Steve, Kay, Mike, and David

and

to the many fine individuals of Otis Engineering Corporation

and

to the many dedicated engineers who make up our great petroleum industry.

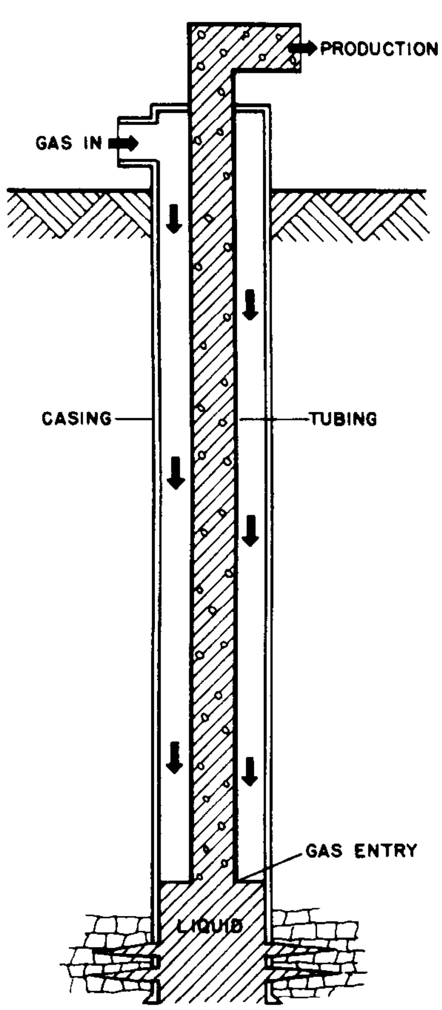

Fig. 1.1A Open end tubing—tubing flow

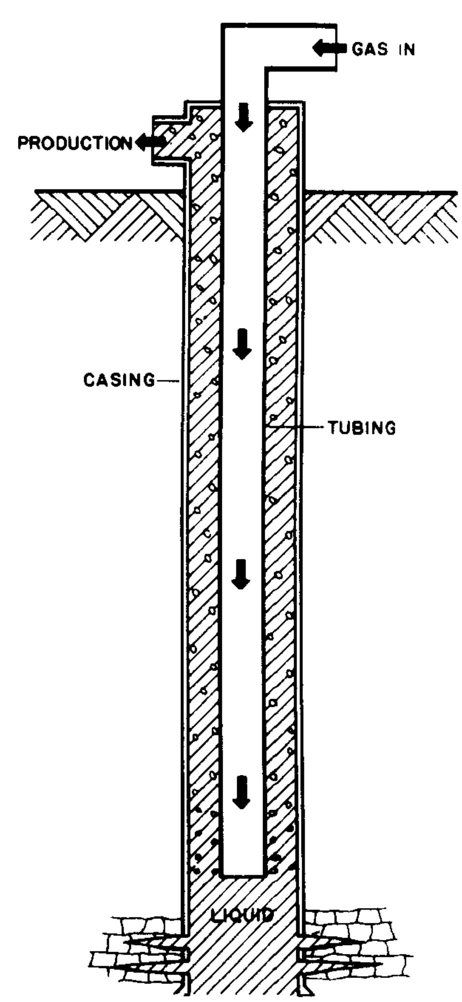

Fig. 1.1B Open end tubing—casing flow

Preface

The gas lift (or air lift) method has been used for many years to lift fluid from depth. In the early 18th century it was used to remove water from mine shafts, as it was the only known practical method for removing the tremendous volumes necessary to keep out the natural seepage. The use of air lift for secondary production of oil was first introduced in Pennsylvania in 1865, but it did not gain popularity until it was introduced in the Gulf Coast area in early 1900. It was used for many years in Louisiana and East Texas to produce large volumes of oil. Companies were formed to furnish compressed air or gas to the oil companies; the success of famous fields such as the Evangeline Field in Louisiana and Smackover and Spindletop in eastern Texas owed a great deal to gas lift.

Gas lift for many years was used after the point of natural flow decline until the time when the well was to be depleted by pump. This early method of lift was called "U-tubing" and was effected by inserting a short string of tubing into the well and introducing high pressure gas either into the annulus or tubing [Figs. 1.1A, 1.1B], depressing the fluid to the bottom of the tubing and producing the well by means of aeration. The high pressure needed to kick off the well and the necessary lowering of pressure after aeration has been established make this type of lift very inefficient. The requirement of high pressure kick-off gas resulted in the development of gas lift valves. Many types were developed in the early 1920's, but their function was to allow lower kick-off pressures and deeper submergence of the tubing string. This was done by injecting air through a series of successively lower valves; the underlying principle—as each lower valve was uncovered by the falling annulus fluid level, the differential across the upper valve, or velocity of the gas through the valve (depending upon the type), would become greater than the set valve spring tension, causing the valve to close.

Intermittent lift was introduced in the mid-1930's as a method of producing a well to depletion. The most efficient of the early intermittent valves was a wire line operated valve that used a selection timing device to actuate a gas-driven piston connected to the wire line.

Modern day gas lift has developed into an engineering science utilizing recent research in two-phase flow and equipment.

It is always difficult to write a book that will be suitable for the practicing engineer or foreman and in addition be useful to the research engineer or scientist. Perhaps this book will be more suited for the man ready to utilize those tools necessary for a practicing production engineer.

Several early chapters in this book will allow the man who has been out of school several years to "bone up" on some of those forgotten fundamentals. A thorough study of the first six chapters will give a person the necessary background to be able to read and understand most technical literature in the area of two-phase flow and gas lift. But the field man who doesn't need these details can use the working curves and examples as a basis for working problems right along with the man of greater technical background. This text, then, should serve many people and purposes.

The publication of *Gas Lift Theory and Practice* has been made possible by Otis Engineering Corporation. Otis Engineering has sponsored many research projects in the area of two-phase flow and has unselfishly continued to release this information for all who are interested. They are to be highly commended in this regard. In addition, they have financed the publication of this book, thereby assuring its being made available to the petroleum industry.

I would like to acknowledge the help received from the following individuals: James P. Brill, Aldon R. Hagedorn, Ben Eaton, Paul J. Root, Ted Doerr, Malcom B. Roach, John Prejean, Lowell Wilhoit, Carl Ivey, Don Taylor, Purvis J. Thrash, Carlos Canalizo, Bob Lee, Gene Garner, Lowell Granstaff, Bill Hayden, Phil Pierce, Tom Smith, Mrs. Julia Reeves, Mrs. Ercell Gregory, and Jimmy Holmes.

In particular, Chap. 5 on curve fitting was written by Paul Root; Chap. 6 on multiphase flow was written by Jim Brill, Ben Eaton, Al Hagedorn, and myself. Purvis Thrash and Carlos Canalizo helped on Chaps. 8-14. Bob Lee helped on Chap. 11. Tom Smith of Gardner Denver Company offered comments and suggestions on Chap. 13. Mrs. Julia Reeves and Mrs. Ercell Gregory helped in typing. Gene Garner helped in the organization and final preparation. Lowell Granstaff, Bill Hayden, and Jimmy Holmes prepared the many drawings and curves. Mac Roach, Phil Pierce, Lowell Wilhoit, John Prejean, and others encouraged the publication of this book in many ways. I would like to express my sincere appreciation to Carlos Canalizo who proofread all the galleys. All original drawings and curves were prepared through courtesy of Otis Engineering Corporation.

Also, I owe a great deal to many of my graduate students who worked on gas lift and multiphase flow projects under my supervision. These include George Fancher, Jr., Dave Dodd, Everett Deschner, Alton Hagedorn, Francisco Ciafaloni, James Brill, Richard Knowles, Donald Andrews, Ben A. Eaton, and Charles Houssiere.

Special thanks are also due Herald Winkler for his many helpful comments and suggestions.

Finally, I would like to acknowledge the love and patience of an understanding wife and family who were neglected on numerous occasions because of my work on this book.

Kermit E. Brown

TULSA, OKLAHOMA

Contents

1

Introduction

In the artificial lifting of a well we are concerned with the following three problems (Fig. 1.2[1]*):

1.1 INPUT FLOW PERFORMANCE

We need to know as much as possible about the reservoir in which the well is located as well as the input flow characteristics of the well itself. This includes formation volumes of oil and gas, static bottom hole pressure, productivity index, permeabilities to oil, gas, and water, type of reservoir, the allowable production rate, manner of completion, possibility of gas or water coning, and possible production problems such as sand, paraffin, etc.

A complete review of reservoir mechanics is given in Chapter 4.

1.2 THE VERTICAL LIFT PERFORMANCE

As soon as the reservoir fluids have entered the well bore, the problem becomes vertical or inclined lift performance. Although the majority of wells are essentially vertical, there are more and more directional wells being drilled for offshore

*Superscript numbers in parentheses denote entries in the Reference section at the end of a chapter.

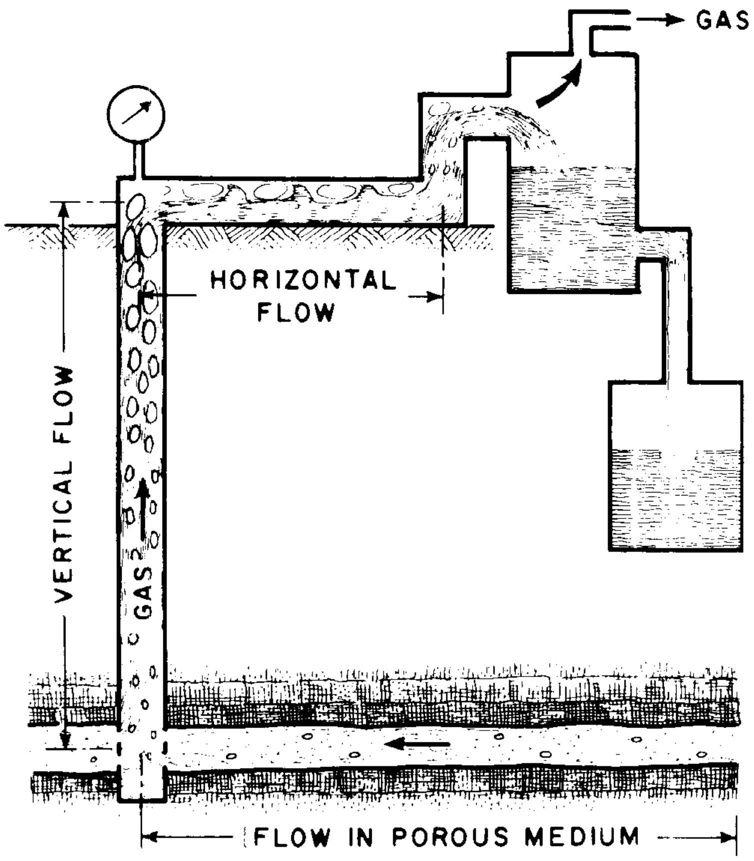

Fig. 1.2 Three stages of production

completions. Although hydrostatic head pressure is the same for the same vertical depth, pressure losses will increase due to the longer length of tubing required to carry the fluids to the surface from an offshore well.

Vertical lift performance is directly affected by the fluid production rate, measured by the amount of gas and water contained in 1bbl of stock tank oil.

The vertical lift performance is materially affected by such factors as (1) tubing size and depth, (2) gas/liquid ratio, (3) water production, (4) separator pressure, (5) length and size of surface flow line, (6) viscosity, (7) other properties of the fluids such as density and surface tension, and (8) production problems such as scale deposits, sand, and paraffin.

A complete review of vertical and horizontal flow performance is given in Chapter 6. A study of the flowing well is given in Chapter 7.

1.3 HORIZONTAL FLOW PERFORMANCE

Once the well fluids have reached the surface, they must be transported from the well head to the storage facilities. The distance of transportation may range from a very short distance to several miles. A serious problem arises when the fluids must be moved from offshore wells to inland storage facilities. The distance involved may then be from 5–50 mi. Often one large flowline may serve to transport fluids from several wells.

In hilly terrain, surface flowlines may be inclined, complicating prediction of surface flowline pressure loss.

Surface flowline length and size and fluid production rate with a particular gas/liquid ratio and water percentage per barrel of stock tank oil have an influence on the surface well head pressure required to transport fluids through the surface flowline against a set separator pressure. This required surface well head pressure has a direct influence upon the well's flowing bottom hole pressure, which controls the input flow performance.

1.4 PURPOSE OF ARTIFICIAL LIFT

The purpose of artificial lift is to maintain a reduced producing bottom hole pressure so that the formation can give up the desired reservoir fluids. A well may be capable of performing this task under its own power. In its latter stages of flowing life a well probably is capable of producing only a portion of the desired fluids. During this stage of a well's flowing life and in particular, after the well dies, a suitable means of artificial lift must be installed so that the required flowing bottom hole pressure can be maintained.

Maintaining the required flowing bottom hole pressure is the basis for the design of any artificial lift installation: if a predetermined drawdown in pressure can be maintained, the well will produce the desired fluids. This is true regardless of the type of lift installed. In gas lift operations, a well may be placed on continuous or intermittent lift. In continuous flow the flowing bottom hole pressure will remain constant for a particular set of conditions, while in intermittent flow the flowing bottom hole pressure will vary with the particular operation time of one cycle of production (Fig. 1.3). In this latter case a weighted average flowing bottom hole pressure must be determined for one cycle and, hence, for a day's production. In many instances an inefficient lift installation may be purposely installed to maintain the desired flowing bottom hole pressure. Although the lift installation itself may be inefficient, it obtains maximum production. Economics enters into the design of any lift installation.

Various types of artificial lift methods are available: beam-type sucker rod pump, piston-type sucker rod pump, hydraulic oil well pump, electrical submergible centrifugal pump, rotating rod pump, sonic pump, plunger lift, and gas lift—the subject of this book.

The advantages and disadvantages of all types of artificial lift will be briefly discussed.

1.5 TYPES OF ARTIFICIAL LIFT OTHER THAN GAS LIFT

In any one year in the United States some 25,000 to 30,000 wells are placed on artificial lift. Although the majority of these wells are placed on sucker rod pumping systems (70–75%) a majority of the remaining

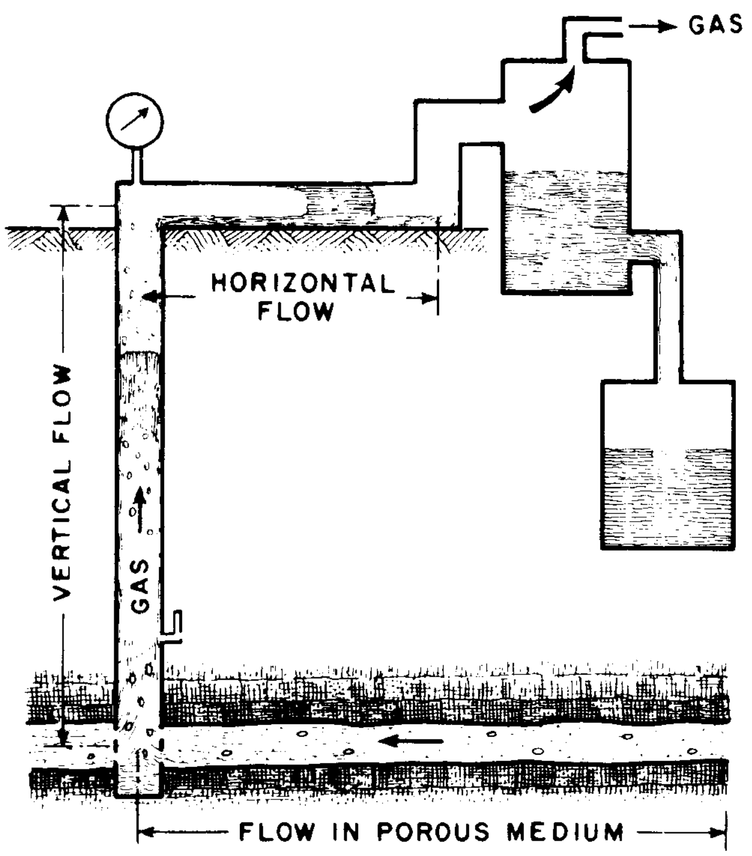

Fig. 1.3 Three stages of production in an intermittent gas lift well

(15–20%) are placed on gas lift. In addition, as more and more offshore wells and not readily accessible land wells are completed, the popularity of lifting by gas continues to grow. For fields with a high corrosion environment, gas lift offers a minimum of surface equipment. For ocean floor completions gas lift offers a means of completion requiring no additional equipment on the Christmas tree.

Gas lift is utilized both in wells where a high production rate is necessary and in the depletion stages of a well when only a few barrels per day are producible. In areas of western Texas and New Mexico wells on gas lift are producing 20,000–30,000 B/D (barrels per day). These wells are producing from the casing-tubing annular space with gas injected down the tubing string. Many wells being lifted from the annular space are making 4000–10,000 B/D.

A general misconception is that wells cannot be depleted by gas lift. Actually many wells of very low bottom hole pressures are being successfully lifted by gas lift. A chamber installation is generally utilized: a means of gas lift that incorporates an accumulation chamber at the bottom of the well so that a minimum pressure is obtained, allowing maximum fluid entry. This type of installation is described in detail in Chapter 9.

1.51 Modern Sucker Rod Pumping

The principle of lifting fluids by means of a subsurface pump utilizing a string of rods is probably the oldest of artificial lift concepts (Fig. 1.4). It is some 2000 years old and still represents a popular means of artificial lift.

The following description of the modern sucker rod pumping system is from Bethlehem Steel's *Sucker Rod Handbook:*[2]

"The sucker rod pumping system is comprised of four principal parts: The pump, the sucker rod string, the pumping unit, and the prime mover.

"As energy is transmitted from the prime mover to the polished rod, speeds are reduced through the speed reducer on the gear box. Rotary motion is translated to reciprocating motion through the crank, pitman and beam. The sucker rod string is used to transmit horsepower from the beam to the pump. When the pump is actuated, work is done on the well fluid as it is lifted to the surface and into the stock tanks."

Numerous articles and books have been written on sucker rod pumping. It is not our purpose here to point out the limitations or advantages of any type of artificial lift and therefore only a description of each type of lift will be given.

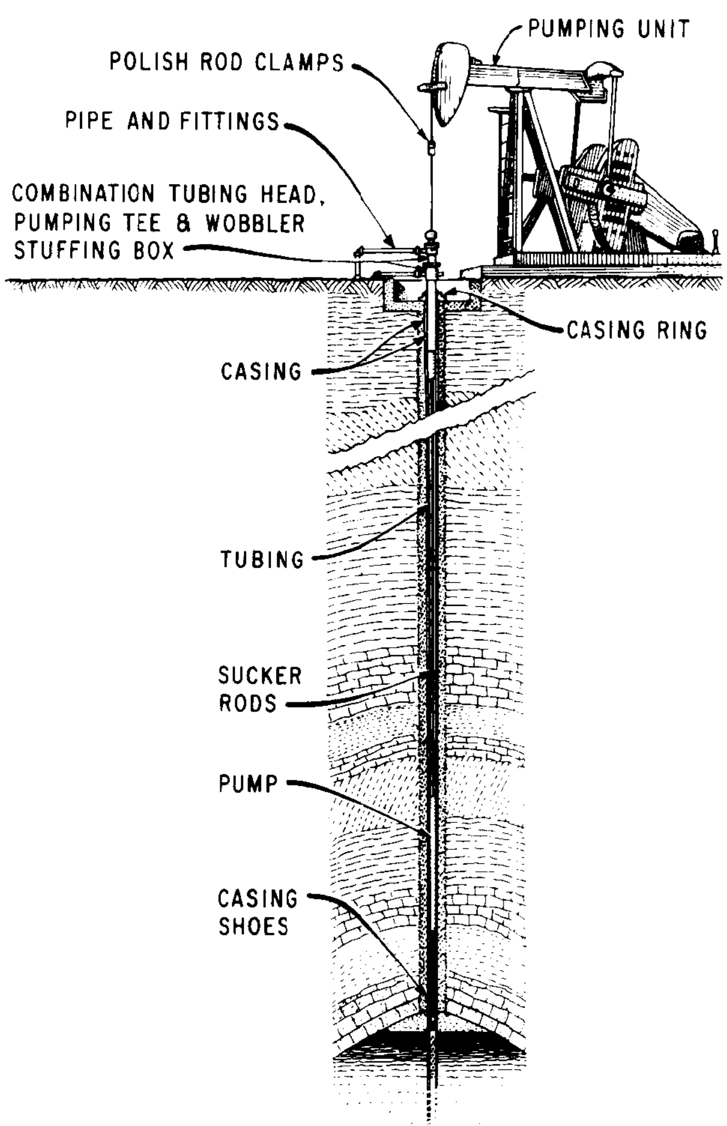

Fig. 1.4 Sucker rod pumping

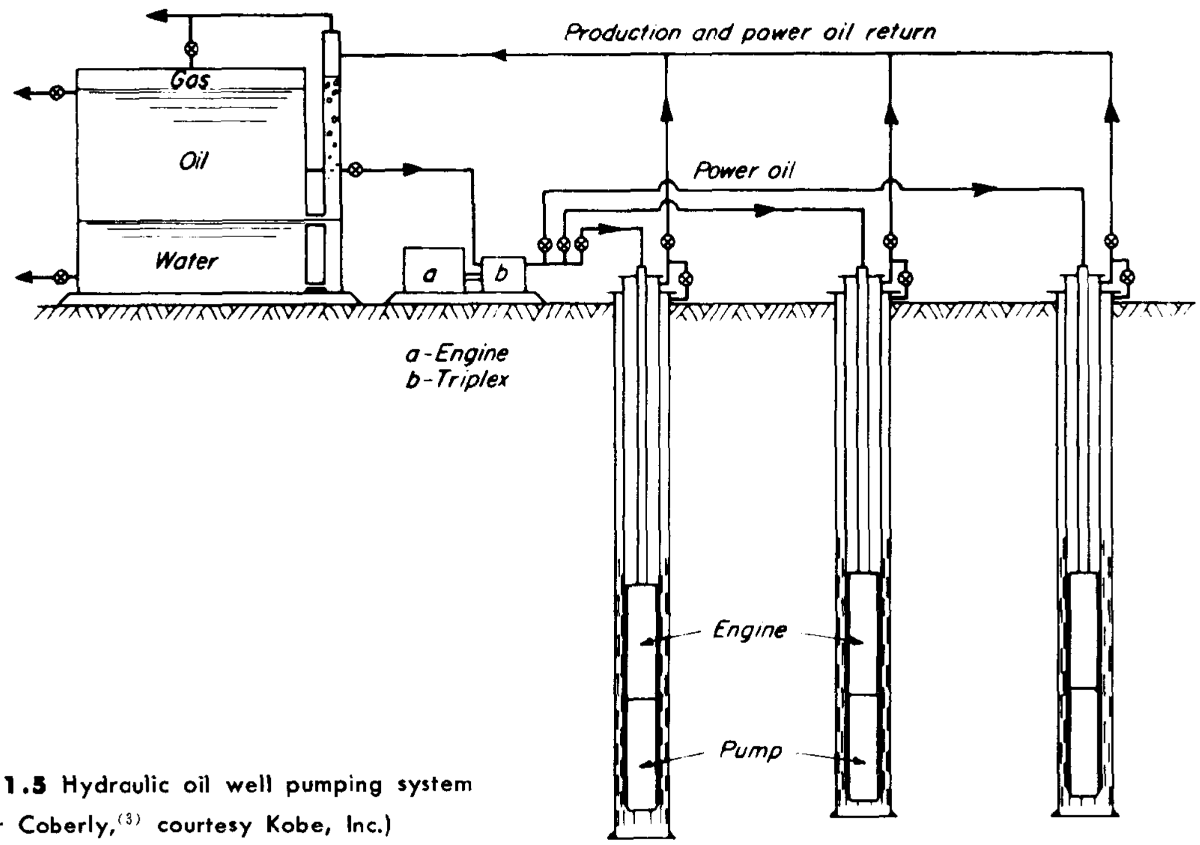

Fig. 1.5 Hydraulic oil well pumping system (after Coberly,[3] courtesy Kobe, Inc.)

1.52 Hydraulic Oil Well Pumping

Hydraulic oil well pumps, as the name implies, are bottom hole pumps which are fluid powered (Fig. 1.5). Actually this includes using both liquid and gas as the power transmitting fluid. Generally, however, a liquid oil is preferred for the power fluid, and to my knowledge gas has not been used as a source of power to actuate these pumps. The essential difference between this type of system and a sucker rod system is in the power transmitting media—power oil for the hydraulic pump, and sucker rods for the sucker rod system. The main part of the downhole equipment is a reciprocating engine that is directly connected to a reciprocating pump. Of course the same basic principle applies to a rotary engine and pump installation.

Two basic reciprocating pump systems are:[3] (1) an oscillating column system in which there is alternate application and release of pressure to the pump through a well head tube and (2) a system in which liquid is applied continuously to the pump. It is quite obvious that the oscillatory system would give difficulty due to fluid compressibility, and it is therefore no longer used commercially. All systems on the market today use a system having a continuous flow of power fluid to the pump.

1.53 Electrical Centrifugal Submergible Pumps

The submergible pump is composed of five basic components which include: (1) an electric motor, (2) a multistage centrifugal pump, (3) an electric cable from the surface to the pump, (4) a switchboard, and (5) a power transformer (Fig. 1.6).[4] The assembled pumping unit is essentially a single rotating shaft with the motor rotors on the lower end and the pump impellers on the top end. A most important factor is that the inside diameter of the casing controls the diameter of the unit.

This type of pump is particularly noted for its ability to move large volumes of well fluids. Its capacity may exceed 20,000 B/D and yet smaller units are capable of economically producing less than 200 B/D.

The entire pumping system is lowered, suspended on the tubing string, to the desired setting depth in a well. A cable from the surface supplies electricity to the motor.

This type of pump is also particularly suitable for usage in the water well industry. Hundreds of water wells, e.g., for irrigation have been placed on submergible electrical pumps.

1.54 Rotating Rod Pump

In addition to the four main types of lift (sucker rod pumping, gas lift, hydraulic pumping, and electrical submergible pumping), there are other types of artificial lift being utilized.

One is a rotating rod pump which operates on the same principle as the electrical submergible centrifugal pump, but utilizes a rotating rod instead of an electrical cable as its means of power (Fig. 1.7). This allows an internal combustion engine to be used as its prime mover on

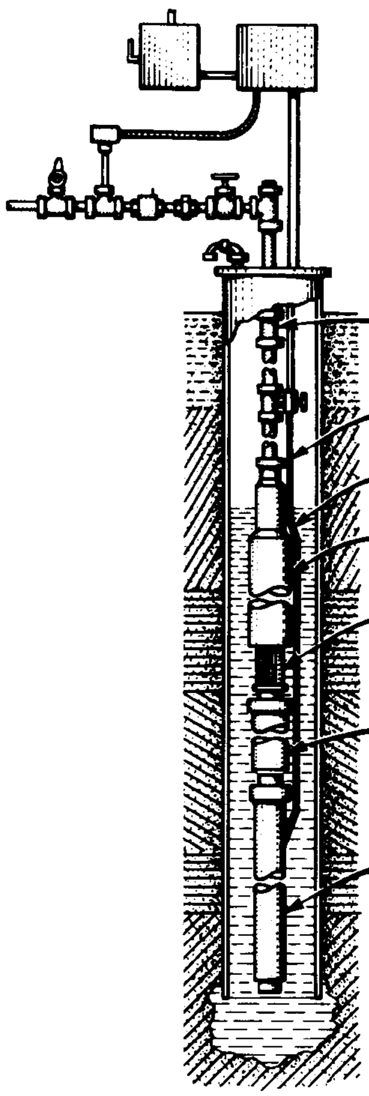

Fig. 1.6 Electrical submergible pump

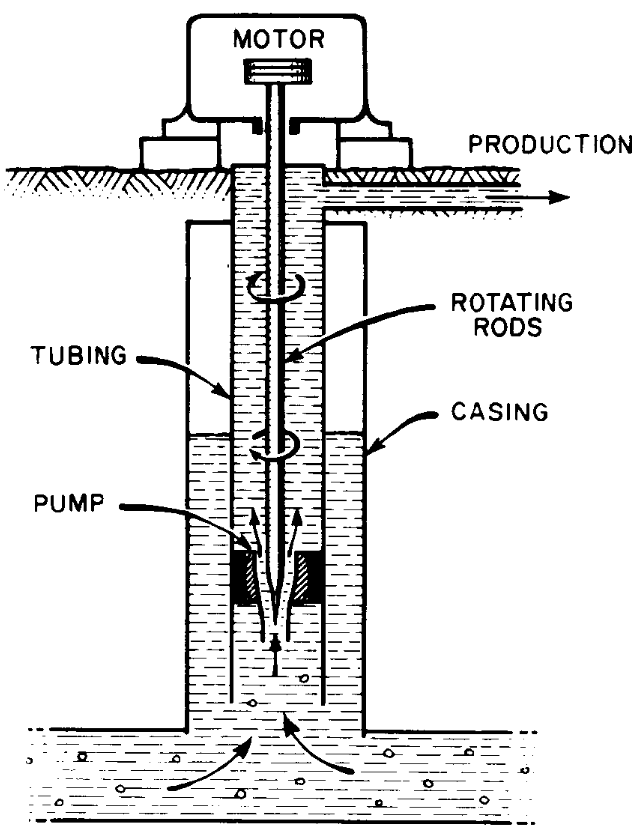

Fig. 1.7 Rotating rod pump

the surface. This pump is generally utilized for shallow water production since a rotating rod string offers a shallow depth limitation as compared to other types of lift.

1.55 Sonic Pump

A type of lift being used at the present time is the so-called "sonic pump" as listed in a brochure by Johnston Testers, Inc.[5] (Fig. 1.8):

The Sonic Oil Well Pump is a mechanical device, actuated by any conventional source of power. It is designed to vibrate a string of tubing in such manner that a series of valves, installed in the tubing collar, will lift the fluid to

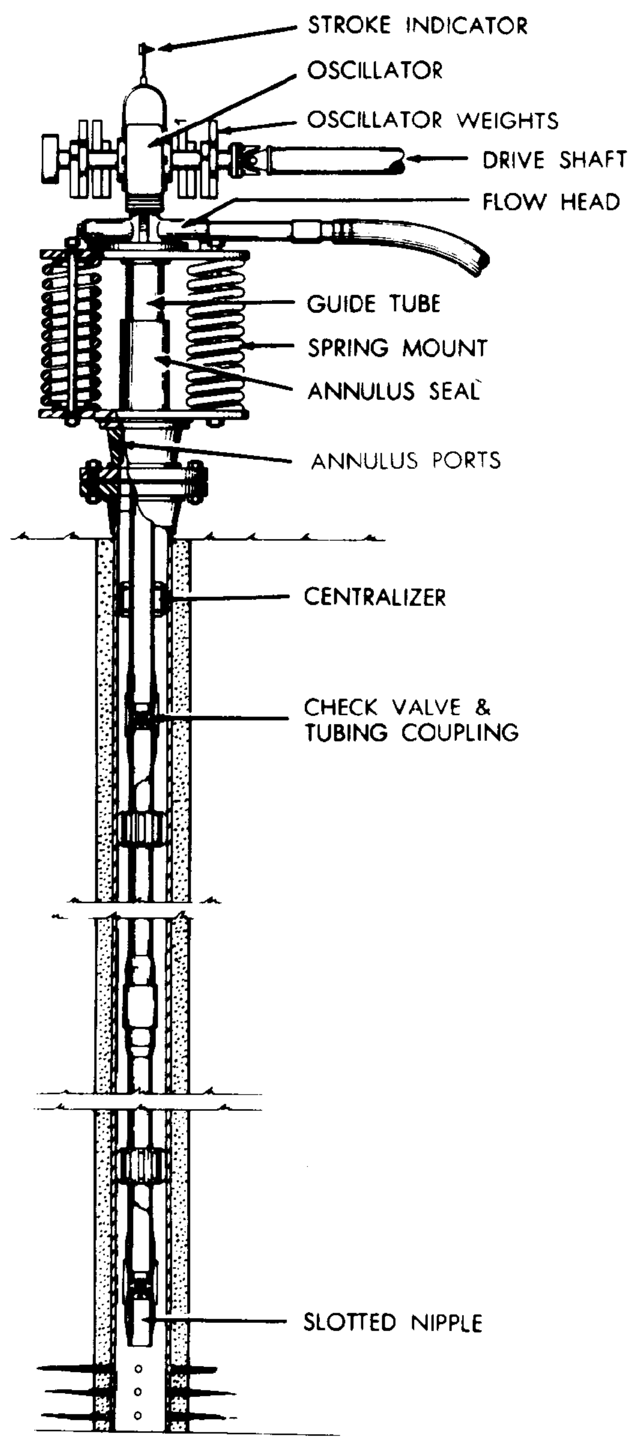

Fig. 1.8 Sonic pump

the surface. The pump is composed of a spring mount assembly, an oscillator with eight eccentric weights, a universal drive shaft, an A-frame motor mount and valves and tubing guides to centralize the tubing in the casing.

The theory of operation of the Sonic Pump is based on the elastic characteristics of a metal rod or tube, free at both ends, that will vibrate according to the principle of simple harmonic motion. When a steel tube, in this case a string of oil well tubing, is vibrated at one end at a rate corresponding to its fundamental frequency, the vibrations are transmitted over the entire length of the tube and form a standing wave on the tubing. The tubing is then said to be in resonance.

The speed depends upon the length of the tubing string and the speed of sound in the tubing. This speed is essentially constant at 990,000 fpm.

1.56 Plunger Lift Method

Although the plunger lift method is generally only a temporary means of prolonging the flowing life of a well, it is sometimes used in conjunction with gas lift and will be discussed briefly here (Fig. 1.9).

In plunger lift a plunger (free piston) fits inside the tubing string with small tolerance and is allowed to travel freely in the tubing string. Its purpose is to provide a sealing interface between the liquid slug produced by the gas volume and the gas volume itself. For the plunger to operate on flowing wells communication must be provided between the tubing and casing so that gas may be accumulated in the casing-tubing annular space between cycles. (This gas is the source of power producing the liquid slug.) Failure to provide such communication usually results in a failure of the plunger to surface. After a well can no longer provide sufficient gas an auxiliary source of injection gas can be provided to supplement formation gas. Wells can produce for long periods of time with this method, but will eventually require a closed gas lift system or another type of artificial lift.

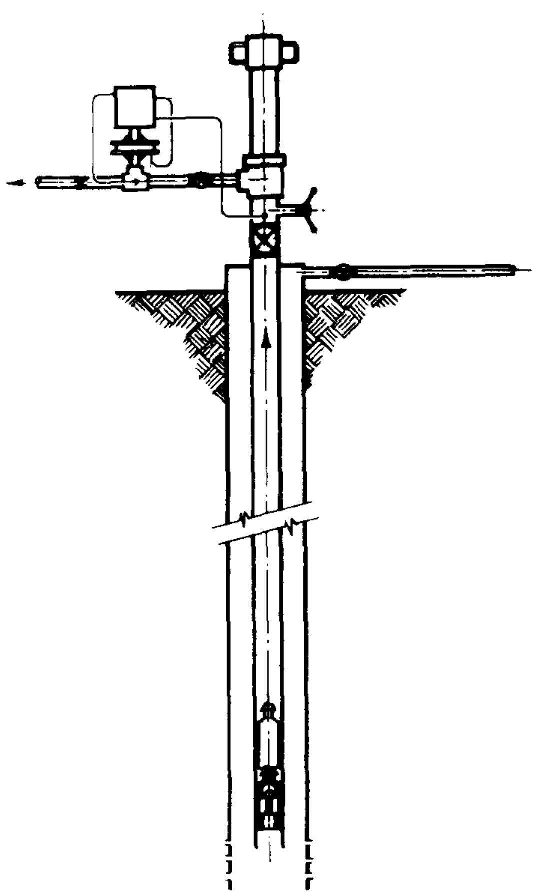

Fig. 1.9 Plunger lift

Most plungers are mechanically closed upon hitting bottom. This provides a positive seal for upward travel. In addition, these plungers are mechanically opened when at the top. This provides a fluid bypass allowing the plunger to fall back to bottom.

Other types of artificial lift have not been mentioned here. Research and development continually improves present lift methods while devising new methods. There is no doubt that the ultimate in artificial lift methods has not yet been achieved.

1.57 Gas Lift

Gas lift may be defined as a method of lifting fluid where relatively high-pressure (250 psi minimum) gas is used as the lifting medium through a mechanical process. This is accomplished by one of the two following methods:

(1) In *continuous flow* a continuous small volume of high-pressure gas is introduced into the eductor tube in order to aerate or lighten the fluid column until reduction of the bottom hole pressure of the fluid column will allow a sufficient differential across the sand face, causing the well to produce the desired rate of flow [Figs. 1.1(a) and 1.1(b)]. To efficiently accomplish this, a flow valve is used that will permit the deepest possible one point injection of available gas lift pressure in conjunction with a valve that will act as a changing or variable orifice to regulate gas injected at the surface. This method is used in wells with a high productivity index and a reasonably high bottom hole pressure relative to well depth.

In this type of well fluid production can range from 300–4000 B/D through normal size tubing strings. On casing flow it is possible to lift in excess of 25,000 B/D. The ID (internal diam) of the pipe governs the amount of flow, provided the well productivity index, bottom hole pressure, gas volume and pressure, and the mechanical conditions are ideal. Smaller volumes can be efficiently lifted using continuous flow where small "macaroni" tubing is used. As low as 25 B/D may be produced efficiently through 1 in. tubing by continuous flow.

(2) *Intermittent flow* involves expansion of a high-pressure gas ascending to a low-pressure outlet (Fig. 1.3).