



Introduction

Canadian Oilwell Systems Company and its subsidiaries are suppliers of oil well Electric Submersible Pumping systems (ESPs). Such pumps are used to lift oil from oil wells so that the oil can be produced. This process is called Artificial Lift. ESPs are one of several methods of artificial lift that can be utilized by an oil producing company.

This paper discusses the various forms of artificial lift, and how an oil well is produced. It is intended for non-technical readers and discusses the basics of these oil production principles.

The following is an outline of the contents of this paper:

Definition of Artificial Lift	Page 2
How an Oil Well is Produced	Page 2
Types of Artificial Lift	Page 3
Beam Pumping/Sucker Rod Pumps	Page 4
Progressing Cavity Pumps	Page 5
Subsurface Hydraulic Pumps	Page 6
Electric Submersible Pumps	Page 7
Gas Lift	Page 8
Summary	Page 9

Definition of Artificial Lift

Any system that adds energy to the fluid column in a wellbore with the objective of initiating and improving production from the well. Artificial lift systems use a range of operating principles, including rod pumping, gas lift and electrical submersible pumps.

How an Oil Well is Produced

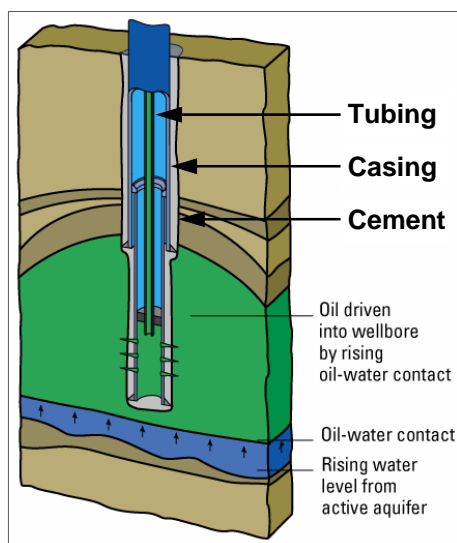
Once an oil or gas reservoir is discovered and assessed, production engineers begin the task of maximizing the amount of oil or gas that can ultimately be recovered from it. Oil and gas are contained in the pore spaces of reservoir rock. Some rocks may allow the oil and gas to move freely, making it easier to recover. Other reservoirs do not part with the oil and gas easily and require special techniques to move the oil or gas from the pore spaces in the reservoir rock to a producing well. Even with today's advanced technology, in some reservoirs more than two-thirds of the oil in the reservoir may not be recoverable.

Before a well can produce oil or gas the borehole must be stabilized with casing, which is lengths of pipe cemented in place. The casing also serves to protect any fresh water intervals that the well passes through, so that oil cannot contaminate the water. A small-diameter tubing string is centered in the wellbore and is sometimes held in place with packers. This tubing will carry the oil and gas from the reservoir to the surface.

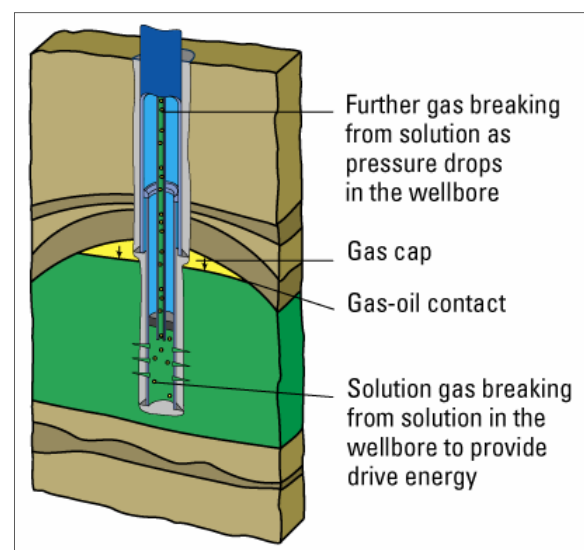
Reservoirs are typically at elevated pressure because of underground forces. The driving force in a reservoir is one of two main types: water drive or gas drive (see below). A water drive reservoir is connected to an active water aquifer that provides the drive mechanism. A gas drive reservoir derives its energy from gas expansion; either from a gas cap or from gas breaking out of solution.

Early in its production life, the underground pressure will often push the hydrocarbons all the way up the wellbore to the surface. Depending on reservoir conditions, this "natural flow" may continue for many years.

When the pressure differential is insufficient for the oil to flow naturally, some method of lifting the liquids, such as mechanical pumps, must be used to bring the oil to the surface.



Water Drive Reservoir



Gas Drive Reservoir



Most wells produce in a predictable pattern called a decline curve. Production will increase for a short period, then peak and follow a long, slow decline. The shape of this decline curve, how high the production peaks, and the length of the decline are all driven by reservoir conditions. Some wells may stop producing in economic quantities in only a few years. Other wells may produce for more than 100 years.

Engineers can do a variety of things to affect a well's decline curve. They may periodically perform an operation called a "workover," which cleans out the wellbore to help oil or gas move more easily to the surface. They may fracture or treat the reservoir rock with acid around the bottom of the wellbore to create better pathways for the oil and gas to move through the subsurface to the producing well.

As an oilfield ages, the company may choose to use a technique called waterflooding. In this case, some of the wells in the field are converted from production wells to injection wells. These wells are used to inject water (often produced water from the field) into the reservoir. This water tends to push the oil out of the pores in the rock toward the producing well and maintains the reservoir pressure. Waterflooding will often increase production from a field.

In more advanced cases, the company may use more advanced techniques, collectively referred to as enhanced oil recovery (EOR). Depending on reservoir conditions, various substances [from steam to nitrogen, carbon dioxide to a surfactant (soap)] may be injected into the reservoir to remove more oil from the pore spaces and increase production.

Throughout their productive life, most oil wells produce oil, gas, and water. This mixture is separated at the surface. Initially, the mixture coming from the reservoir may be mostly oil and gas with a small amount of water. Over time, the percentage of water increases. Increased water production eventually leads to the need for artificial lift, since water is heavier than oil. The pressure formed by the column of oil/water mixture in the wellbore may exceed the reservoir pressure. When this occurs, the well can no longer free flow by natural flow and artificial lift is required for the remainder of the well's life.

Types of Artificial Lift

Artificial-lift methods fall into two groups, those that use pumps and those that use gas.

Pump Types

- Beam Pumping / Sucker Rod Pumps (Rod Lift)
- Progressive Cavity Pumps
- Subsurface Hydraulic Pumps
- Electric Submersible Pumps

Gas Method

- Gas Lift

Each of these methods will be discussed on the following pages:

Beam Pumping/Sucker Rod Pumps (Rod Lift)

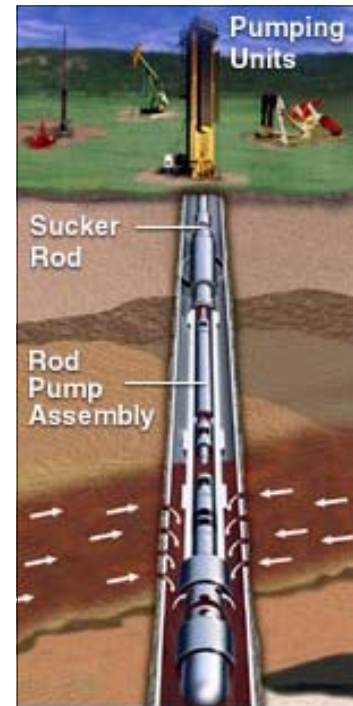
This type of artificial lift utilizes a positive displacement pump that is inserted or set in the tubing near the bottom of the well. The pump plunger is connected to surface by a long rod string, called sucker rods, and operated by a beam unit at surface. Each upstroke of the beam unit lifts the oil above the pump's plunger.

ROD LIFT SYSTEM ADVANTAGES

- High system efficiency
- Optimization controls available
- Economical to repair and service
- Positive displacement/strong drawdown
- Upgraded materials can reduce corrosion concerns
- Flexibility -- adjust production through stroke length and speed
- High salvage value for surface unit and downhole equipment

ROD LIFT SYSTEM DISADVANTAGES

- Limited to relatively low production volumes, less than 1,000 barrels per day.



Beam / Sucker Rod Pump



Typical Beam Pumping Unit



Sucker Rod
(Common to
Beam and PCP
Pumps)

Progressing Cavity Pumps (PCP Pumps)

Progressing Cavity Pumping (PCP) Systems typically consist of a surface drive, drive string and downhole PC pump. The PC pump is comprised of a single helical-shaped rotor that turns inside a double helical elastomer-lined stator. The stator is attached to the production tubing string and remains stationary during pumping. In most cases the rotor is attached to a sucker rod string which is suspended and rotated by the surface drive.

As the rotor turns eccentrically in the stator, a series of sealed cavities form and progress from the inlet to the discharge end of the pump. The result is a non-pulsating positive displacement flow with a discharge rate proportional to the size of the cavity, rotational speed of the rotor and the differential pressure across the pump.

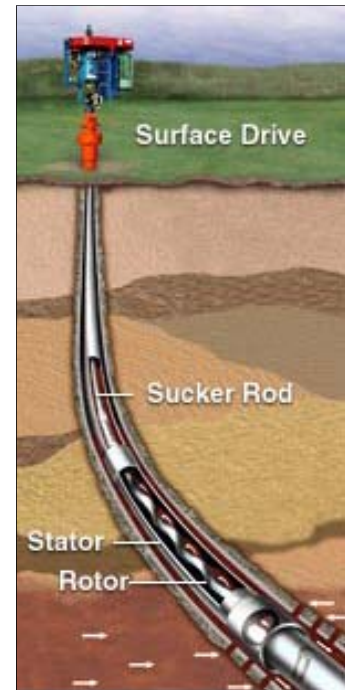
In some cases, PCP pumps are connected to Electric Submersible Pump Motors rather than using a sucker rod string and surface drive.

PCP PUMP ADVANTAGES

- Low capital investment
- High system efficiency
- Low power consumption
- Pumps oils and waters with solids
- Pumps heavy oils
- No internal valves to clog or gas lock
- Quiet operation
- Simple installation with minimal maintenance costs
- Portable, lightweight surface equipment
- Low surface profile for visual and height sensitive areas

PCP PUMP DISADVANTAGES

- Limited lift capabilities (approximately 7,000 ft. maximum)



Subsurface Hydraulic Pumps

Hydraulic Lift Systems consist of a surface power fluid system, a prime mover, a surface pump, and a downhole jet or reciprocating/piston pump. In the operation of a hydraulic lift system, crude oil or water (power fluid) is taken from a storage tank and fed to the surface pump. The power fluid, now under pressure built up by the surface pump, is controlled by valves at a control station and distributed to one or more wellheads. The power fluid passes through the wellhead valve and is directed to the downhole pump. In a piston pump installation, power fluid actuates the engine, which in turn drives the pump, and power fluid returns to the surface with the produced oil, is separated, and is piped to the storage tank. A jet pump has no moving parts and employs the Venturi principle to use fluid under pressure to bring oil to the surface.



HYDRAULIC LIFT SYSTEM ADVANTAGES

Jet Lift

- No moving parts
- High volume capability
- "Free" pump
- Multiwell production from a single package
- Low pump maintenance

Piston Lift

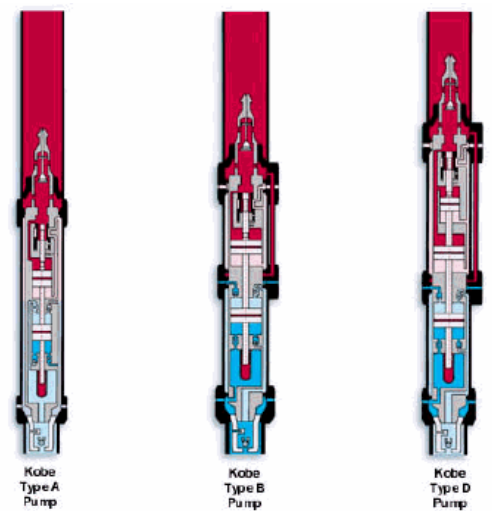
- "Free" or wireline retrievable
- Positive displacement-strong drawdown
- Double-acting high-volumetric efficiency
- Good depth/volume capability (+15,000 ft.)



← Down Hole Jet Pump

HYDRAULIC LIFT SYSTEM DISADVANTAGES

- High initial capital cost
- Complex to operate
- Only economical where there are a number of wells together on a pad.
- If there is a problem with the surface system or prime mover, all wells are off production.



Down Hole Piston Type Pumps

Electric Submersible Pumps (ESPs)

Electric Submersible Pumping (ESP) Systems incorporate an electric motor and centrifugal pump unit run on a production string and connected back to the surface control mechanism and transformer via an electric power cable.

The downhole components are suspended from the production tubing above the wells' perforations. In most cases the motor is located on the bottom of the work string. Above the motor is the seal section, the intake or gas separator, and the pump. The power cable is banded to the tubing and plugs into the top of the motor.

As the fluid comes into the well it must pass by the motor and into the pump. This fluid flow past the motor aids in the cooling of the motor. The fluid then enters the intake and is taken into the pump. Each stage (impeller/diffuser combination) adds pressure or head to the fluid at a given rate. The fluid will build up enough pressure as it reaches the top of the pump to lift it to the surface and into the separator or flowline.

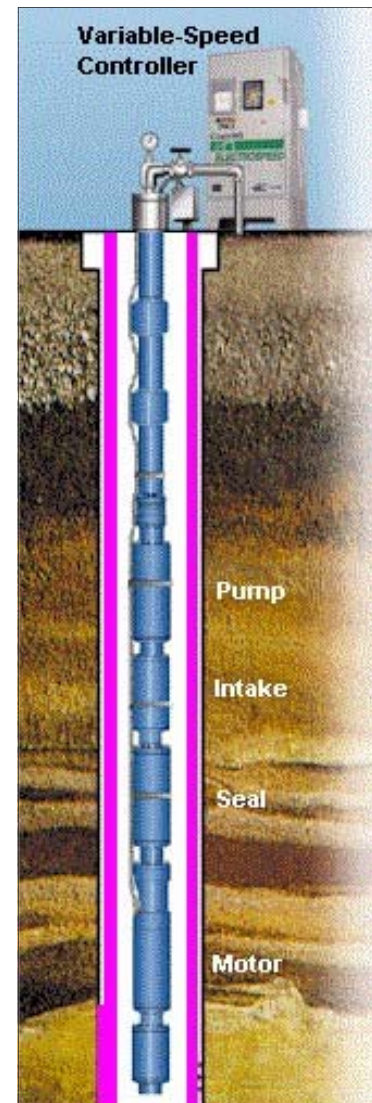
Electric submersible pumps are normally used in high volume (over 1,000 BPD) applications.

ELECTRIC SUBMERSIBLE PUMPING ADVANTAGES

- High volume and depth capacity
- High efficiency over 1,000 BPD
- Low maintenance
- Minimal surface equipment requirements
- High resistance to corrosive downhole environments
- Use in deviated wells and vertical wells with doglegs
- Adaptable to wells with 4 1/2" casing or larger

ELECTRIC SUBMERSIBLE PUMP DISADVANTAGES

- Poor ability to pump sand



Gas Lift

In a typical gas lift system, compressed gas is injected through gas lift mandrels and valves into the production string. The injected gas lowers the hydrostatic pressure in the production string to reestablish the required pressure differential between the reservoir and wellbore, thus causing the formation fluids to flow to the surface.

Essentially, the liquids are lightened by the gas which allows the reservoir pressure to force the fluids to surface.

A source of gas, and compression equipment is required for gas lift.

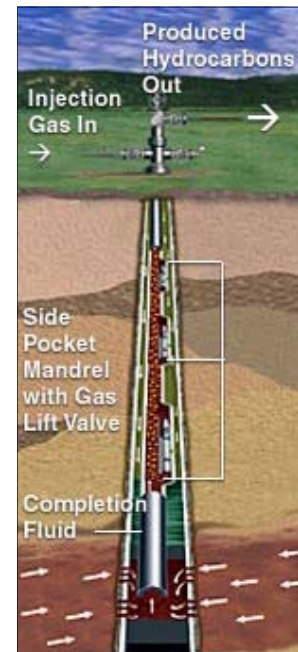
Proper installation and compatibility of gas lift equipment, both on the surface and in the wellbore, are essential to any gas lift system.

GAS LIFT ADVANTAGES

Gas Lift is an artificial lift process that closely resembles the natural flow process and basically operates as an enhancement or extension of that process. The only major requirement is an available and economical supply of pressurized gas.

GAS LIFT DISADVANTAGES

- Not feasible if no source of gas present.
- High initial capital purchase cost.
- Maintenance intensive.
- Difficult to operate.





Summary

Artificial lift is increasing in use as mature oilfields decline in productivity, as newer oil fields require the introduction of artificial lift sooner, as improvements in oilfield management practice become more widely deployed and more rapidly adopted, and as oil volumes pumped annually increase globally.

The following table illustrates the primary advantages and shortcomings of each artificial lift technology:

Pump Type		Electric Submersible	Beam / Sucker Rod	Progressive Cavity	Subsurface Hydraulic	Gas Lift
Positive Features	High Volume	X		X	X	X
	High Volume Capacity	X			X	X
	Low Maintenance	X	X	X		
	Economical to Repair / Service		X	X	X	X
	Low Capital Investment		X	X		
	Pump Heavy Oil		X	X		
Shortcomings	Limited Lift Capabilities			< 5,000 ft		
	High Initial Capital cost	X			XX	XX
	High Power Consumption	X		X		
	Limited Ability to Pump Sand	X	X		X	X
	Operating Complexity / Difficulty				X	X
	If Prime Mover Fails, all Wells Stop				X	X
	Maintenance Intensive				X	X
	Requires Source for Gas for Injection					X