Artificial Lift Systems

By

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Lecture Outline

- Artificial Lift Systems
  - Sucker Rod/Beam Pumping
  - Plunger Lift
  - Progressive Cavity Pump (PCP)
  - Hydraulic Pump
  - Electric Submersible Pump (ESP)
  - Gas Lift
  - Foam Lift
- Design and Selection Considerations
  - The Reservoir and Well Deliverability
  - The Piping and Artificial Lift System
  - Environmental Constraints
  - Operational Constraints
  - Economics

Introduction

- AL systems are the technologies used to augment fluid production from the reservoir. These fall into several categories depending on the operating principle, design and energy source. Production rate from wells may need to be augmented principally for two reasons;
  - Inadequate reservoir drive and energy to produce fluid from the reservoir
  - Non-economic production rate from reservoir's natural energy drive

- Aim of Artificial Lift Systems
  - Reduce the weight of the hydrostatic column on the reservoir, by reducing the density of the fluid column, thereby reducing the drawdown on the reservoir ($\overline{p}$ - p_{wf}), so the formation can give up the desired reservoir fluid
  - Add energy to the reservoir fluid for lifting, this also achieves the aim above.

When Do we Need Artificial Lift?

Low Reservoir Pressure/ Production Rate

- When reservoir pressure drops and cannot support the weight of column and losses in the line

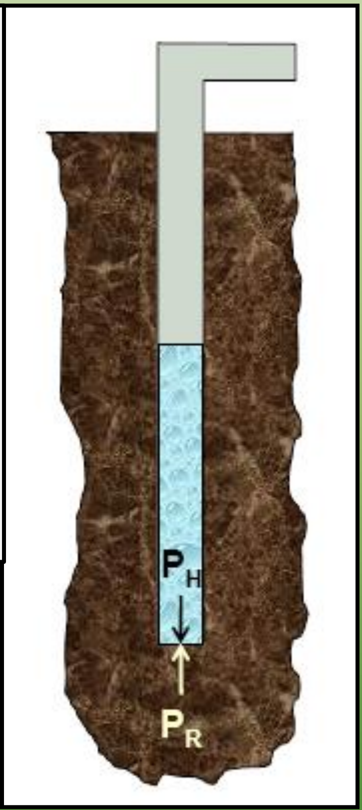
$P_{reservoir} < P_{line} + P_{hydrostatic}$

- When economic production rates cannot be achieved by natural drive and energy of the reservoir.

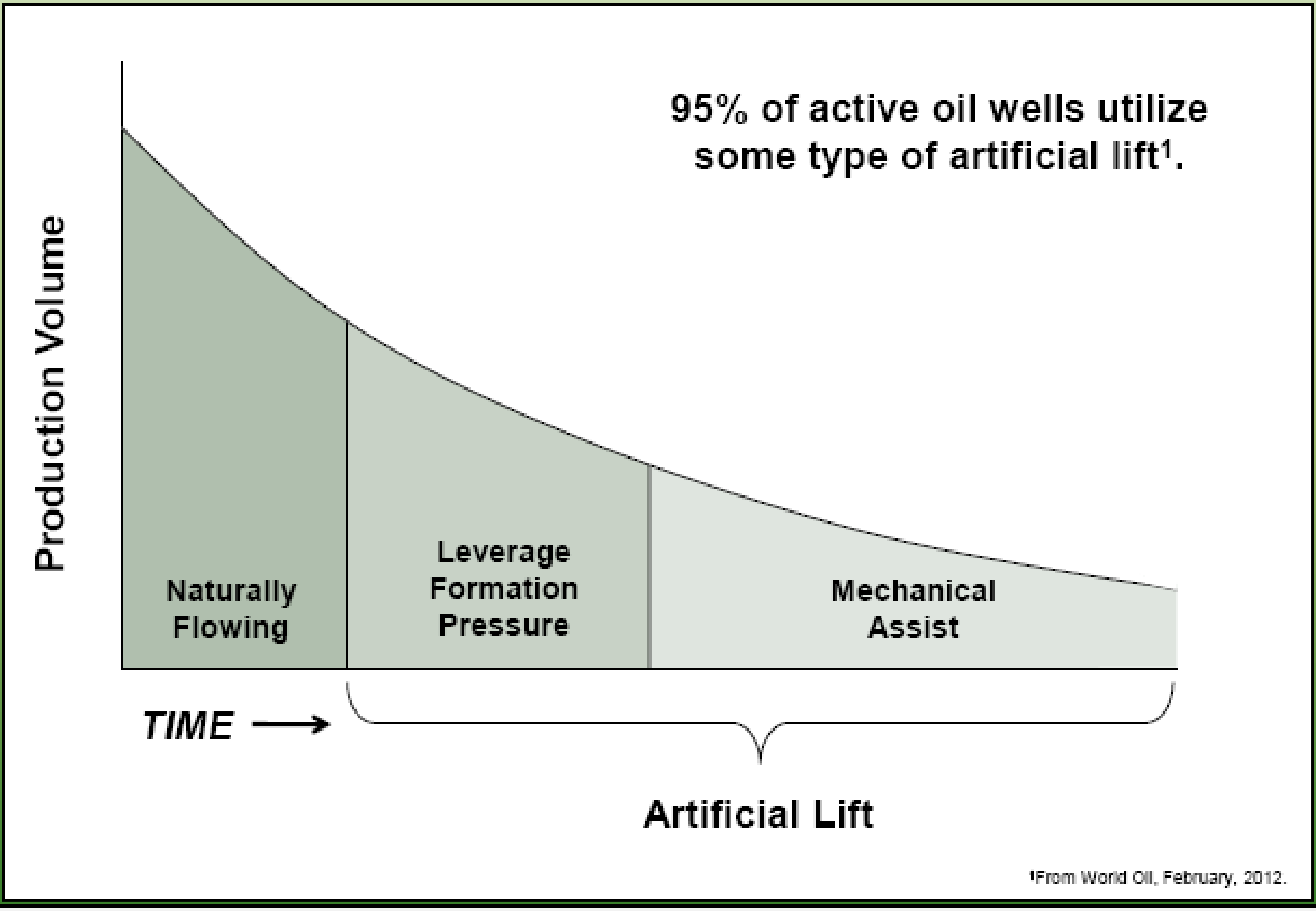
Liquid Loading

When the hydrostatic gradient of the liquid column prevents gas from coming into the well in low rate gas and condensate reservoirs.

$P_{reservoir} < P_{hydrostatic}$



Percentage of Wells on Artificial Lifts



Most wells will Need Artificial Lift Sometimes in their Productive Life

Operational Classification of Pumps

Dynamic Pumps

These pumps operate by developing a high liquid velocity and converting the velocity to pressure in a diffusing flow passage. They continuously impart kinetic energy to the pumped fluid by means of a rotating impeller, propeller or rotor.

A centrifugal pump consists of an impeller with an intake at its center. Centrifugal pump include radial, axial and mixed flow units.

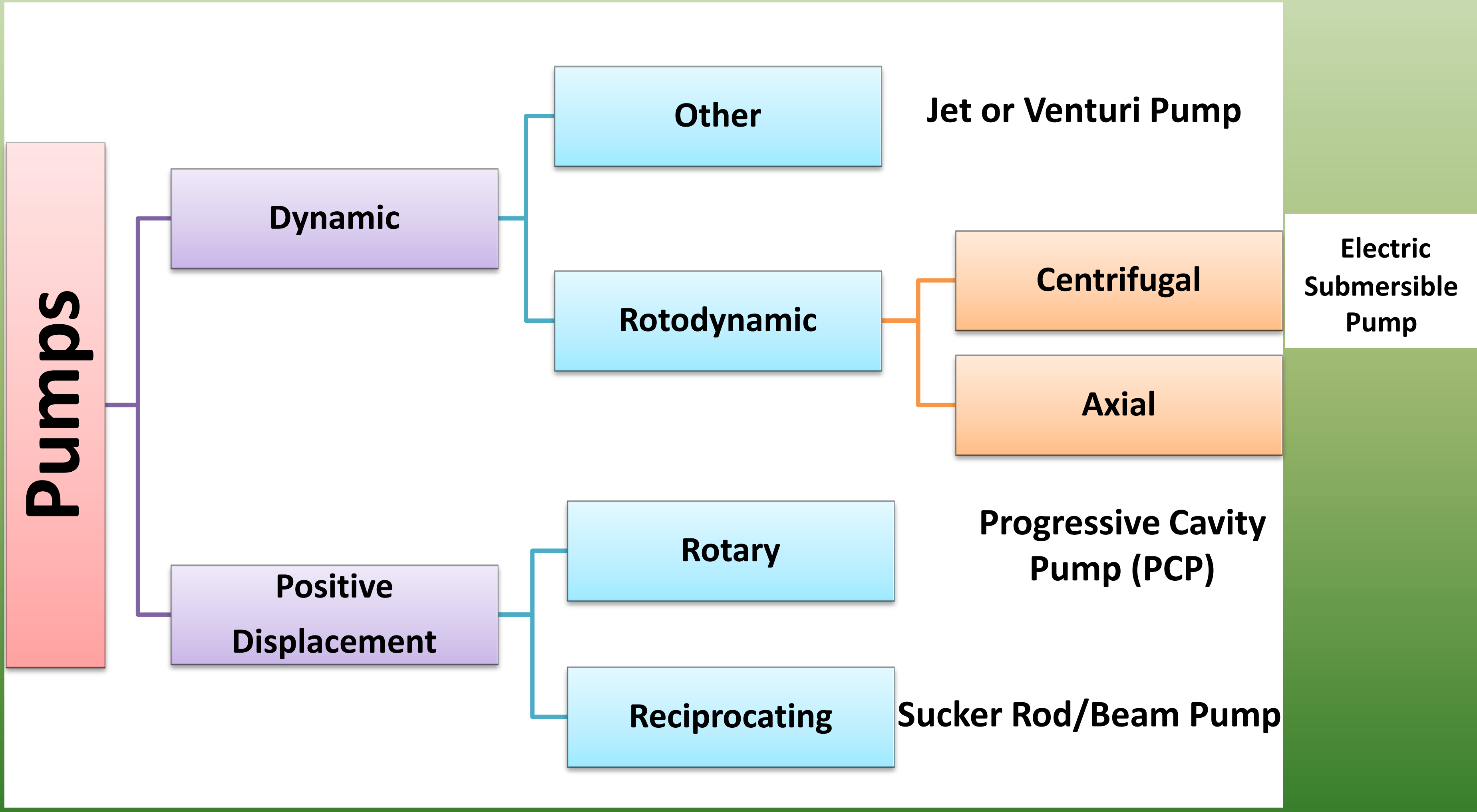
Examples include;
Submersible pump
Vertical multistage pump
Horizontal multistage pump

Positive Displacement Pumps

The positive displacement pump operates by trapping a fixed amount of fluid and forcing the trapped volume into the pumps discharge, it alternately fills a cavity and then displacing the trapped volume of liquid. The positive displacement pump delivers a constant volume of liquid for each cycle against a varying discharge pressure or head.

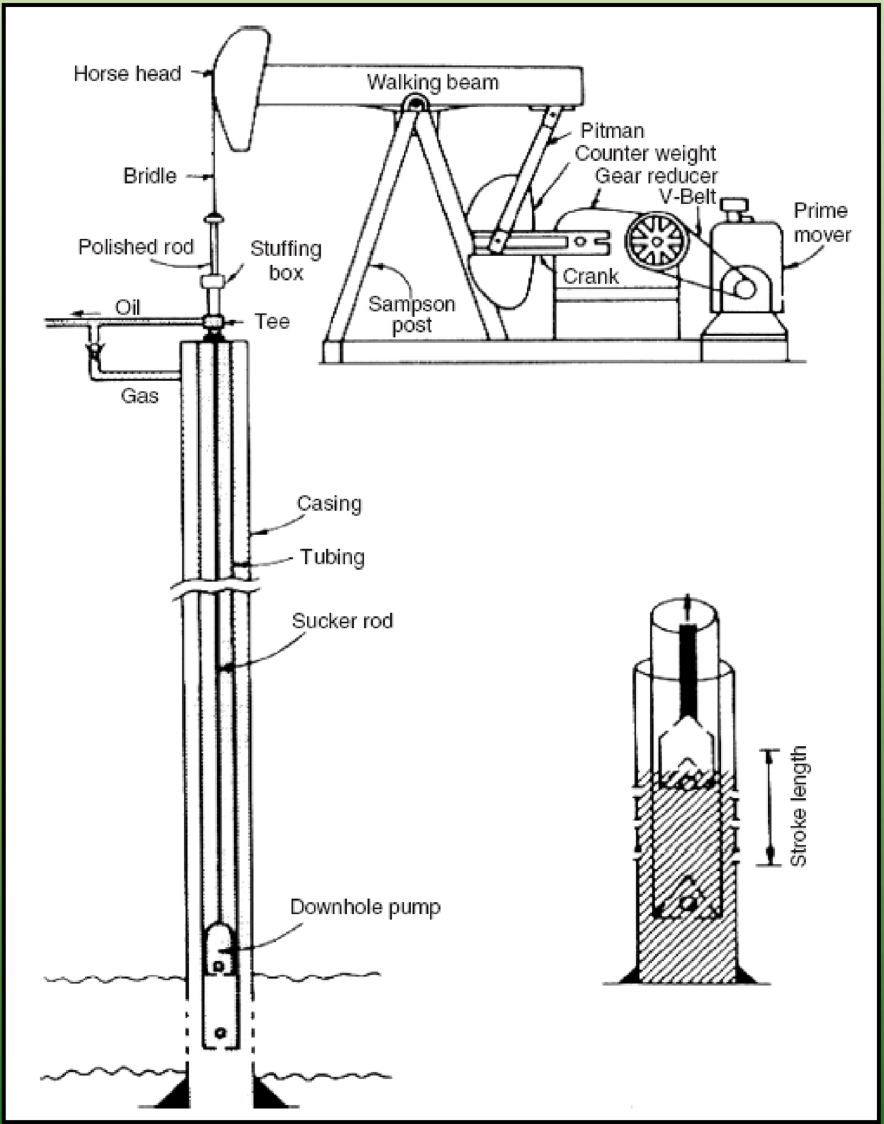
Examples;
Reciprocating pumps- piston, plunger
Rotary pumps – Progressive cavity pumps (PCP)

Operational Classification of Pumps



Sucker Rod or Beam Pump

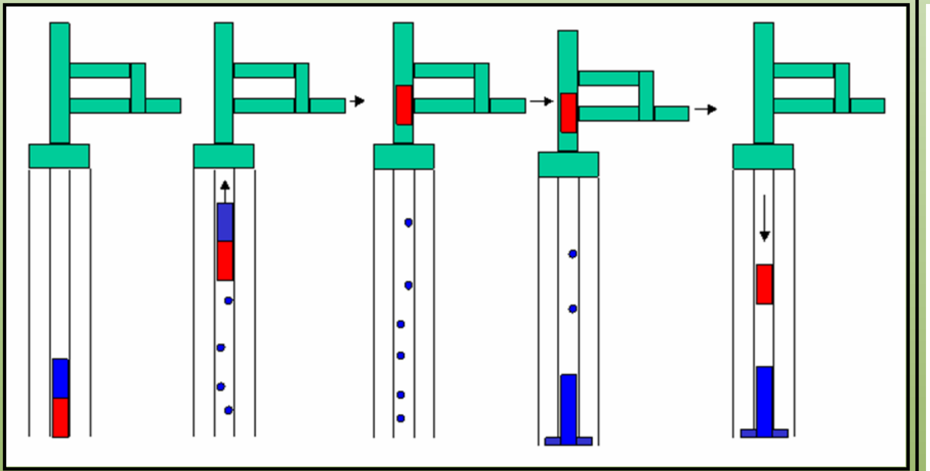
(Reciprocating Positive Displacement Pump)



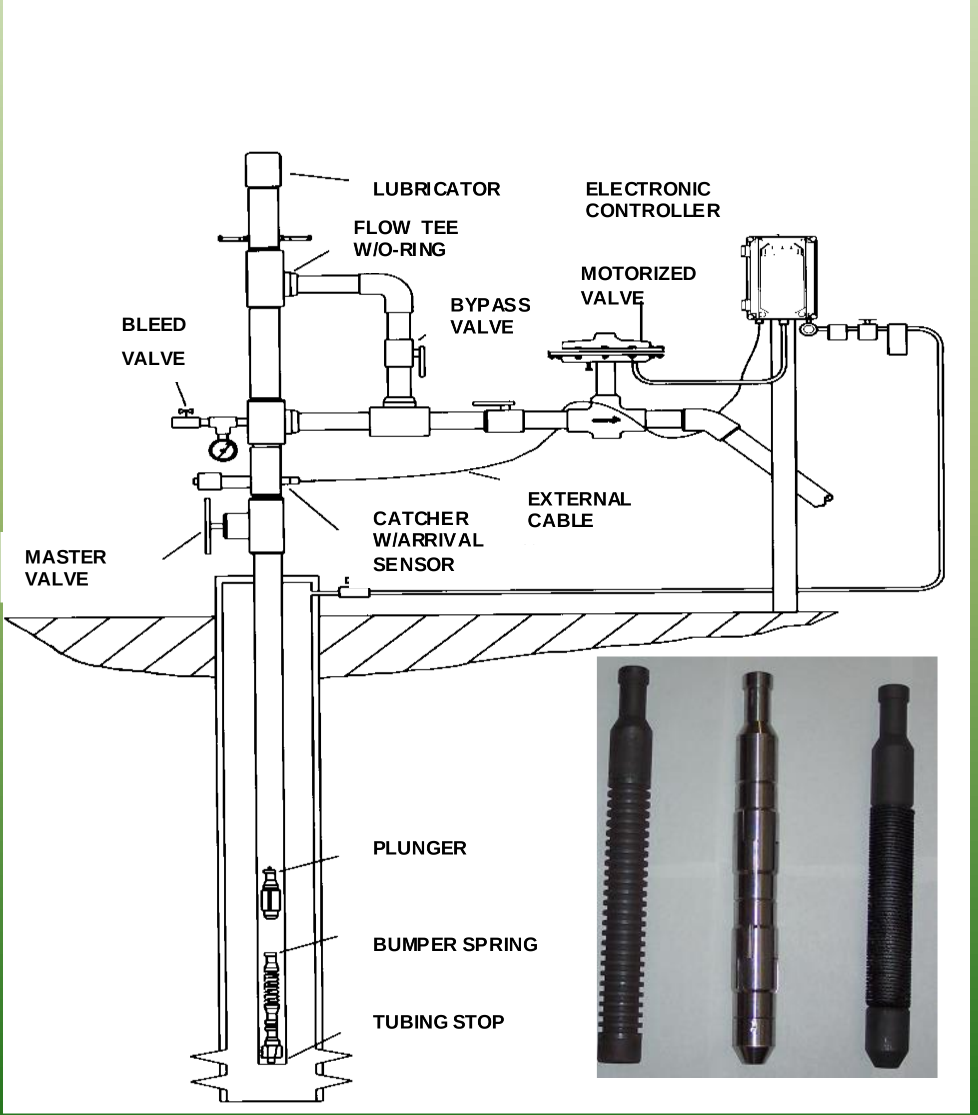
In this pump, a down-hole plunger is moved up and down by a string of rods (sucker rods) connected to an engine at the surface. The plunger's movement displaces produced fluid into the tubing via a pump consisting of a combination of travelling and standing valves located in the pump barrel.

Plunger Lift

(Reciprocating Progressive Cavity Pump)

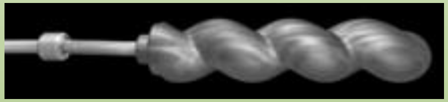


A Typical Plunger Cycle

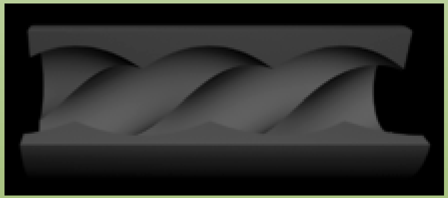


Plunger Lift is a method of artificial lift that uses the well's own energy, either pressure or gas rate, to effectively lift fluids to the surface. The plunger creates a seal with the tubing wall to reduce the amount of gas/liquid slippage and lift the fluid to surface as completely as possible

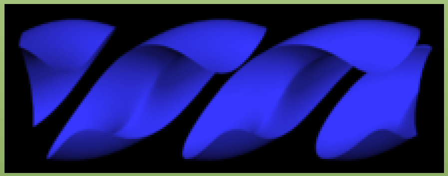
Progressive Cavity Pump (PCP)
(Rotary Positive Displacement Pump)



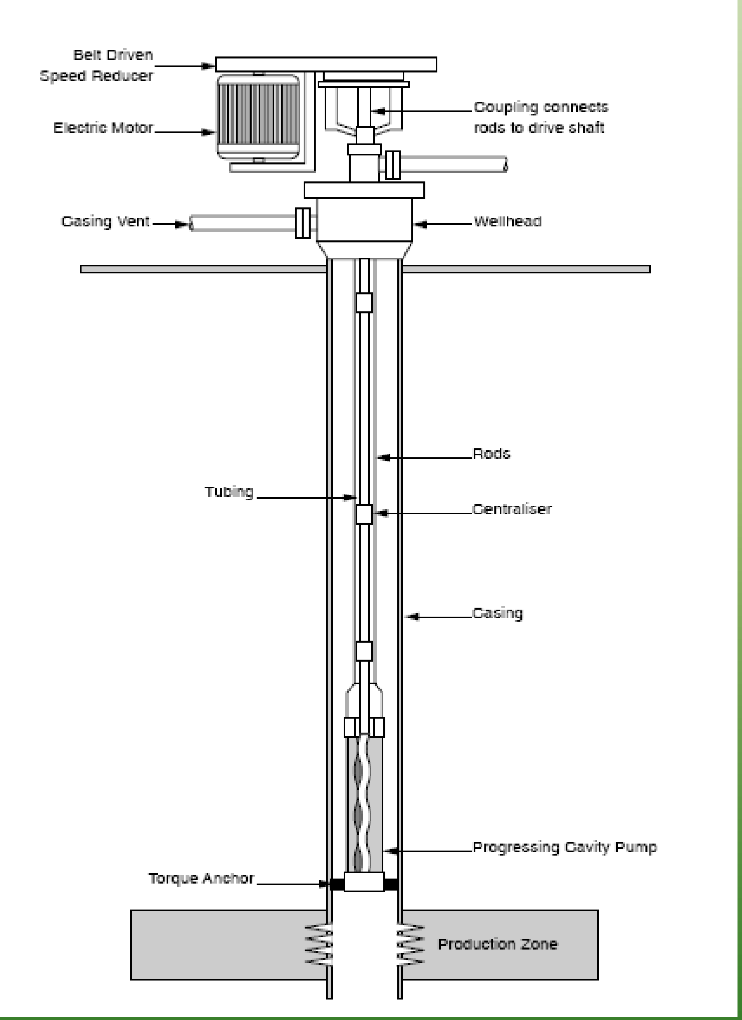
Helical metal Rotor



Stationary elastomer

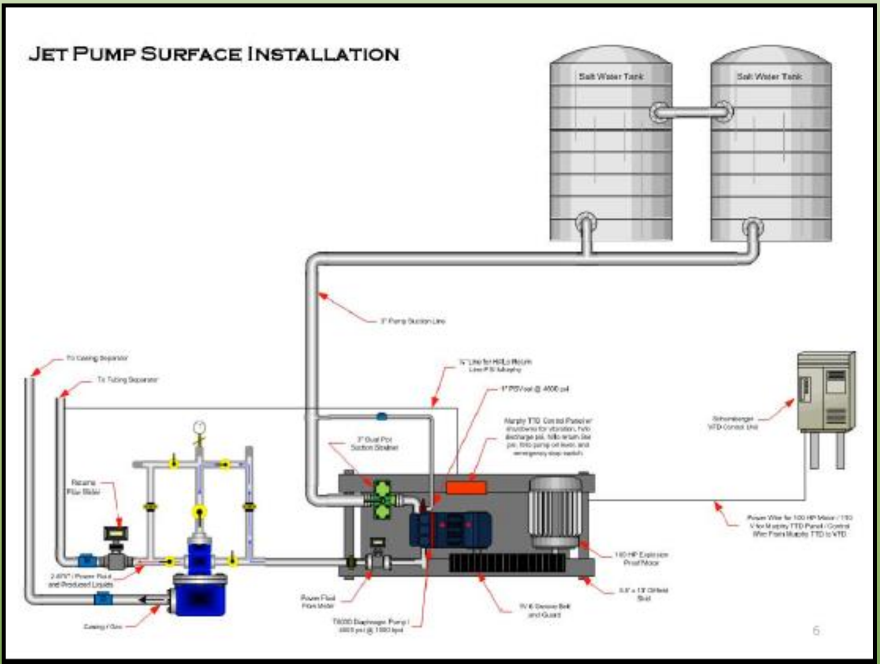


Shape of cavity between stator and rotor for moving fluid



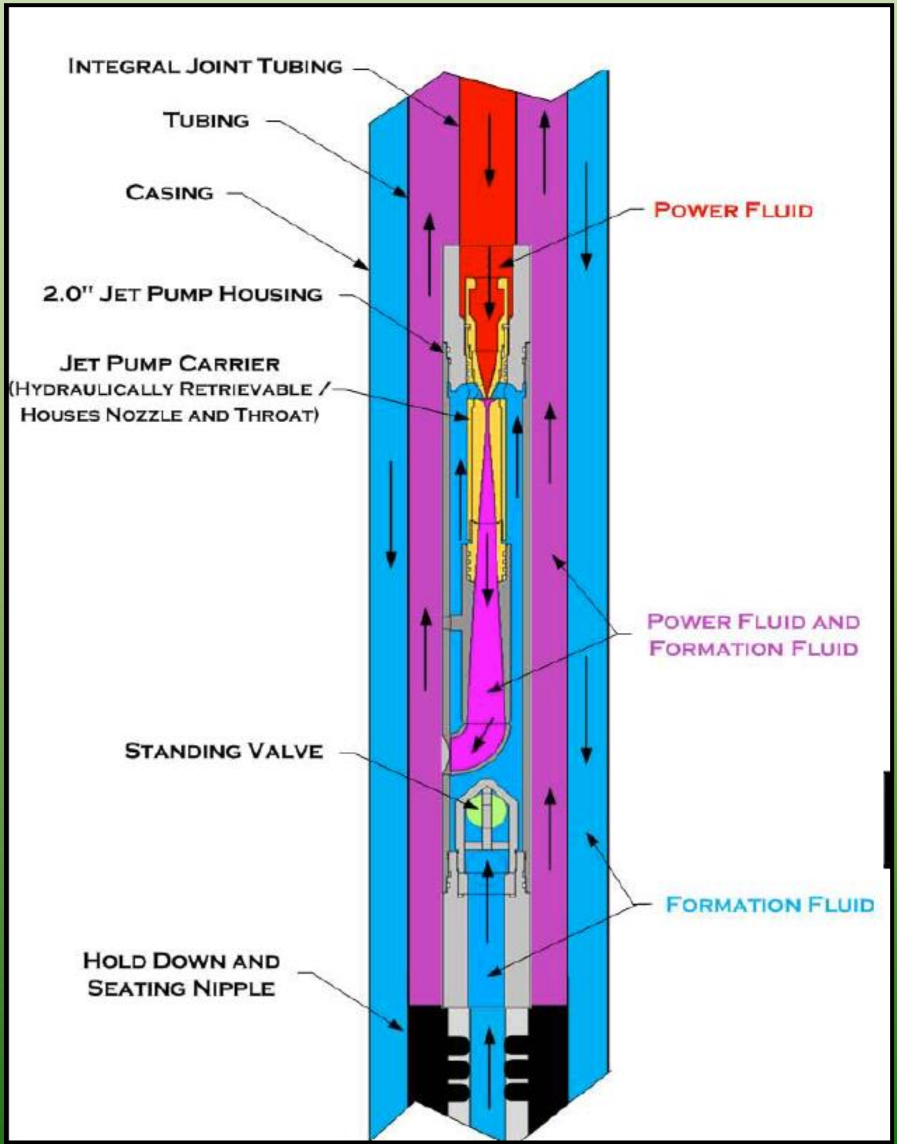
PCP-This pump employs a helical metal rotor rotating inside an elastomeric, double helical stator. The rotating motion is supplied by either a downhole electric motor or by rotating rods from an engine at the surface.

Hydraulic Pump
(Dynamic Pump)



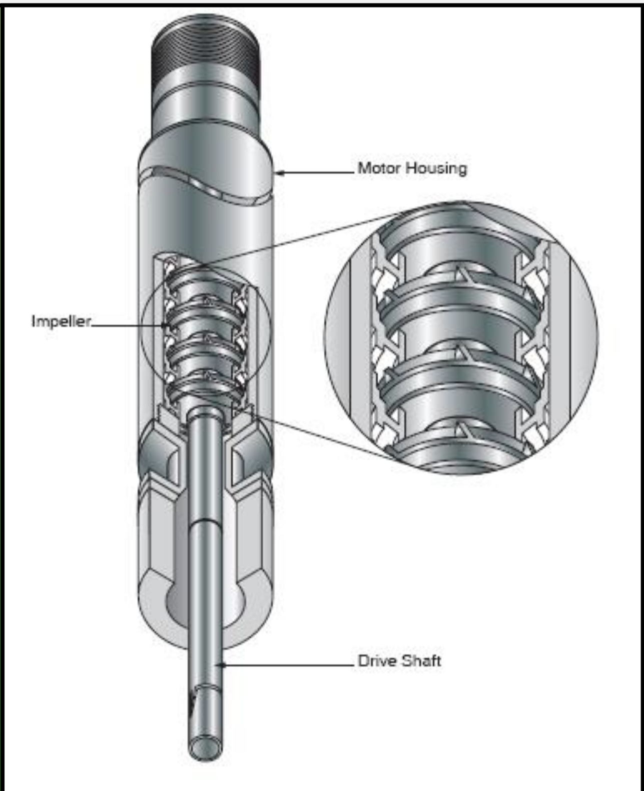
Hydraulic pumping are in two categories;

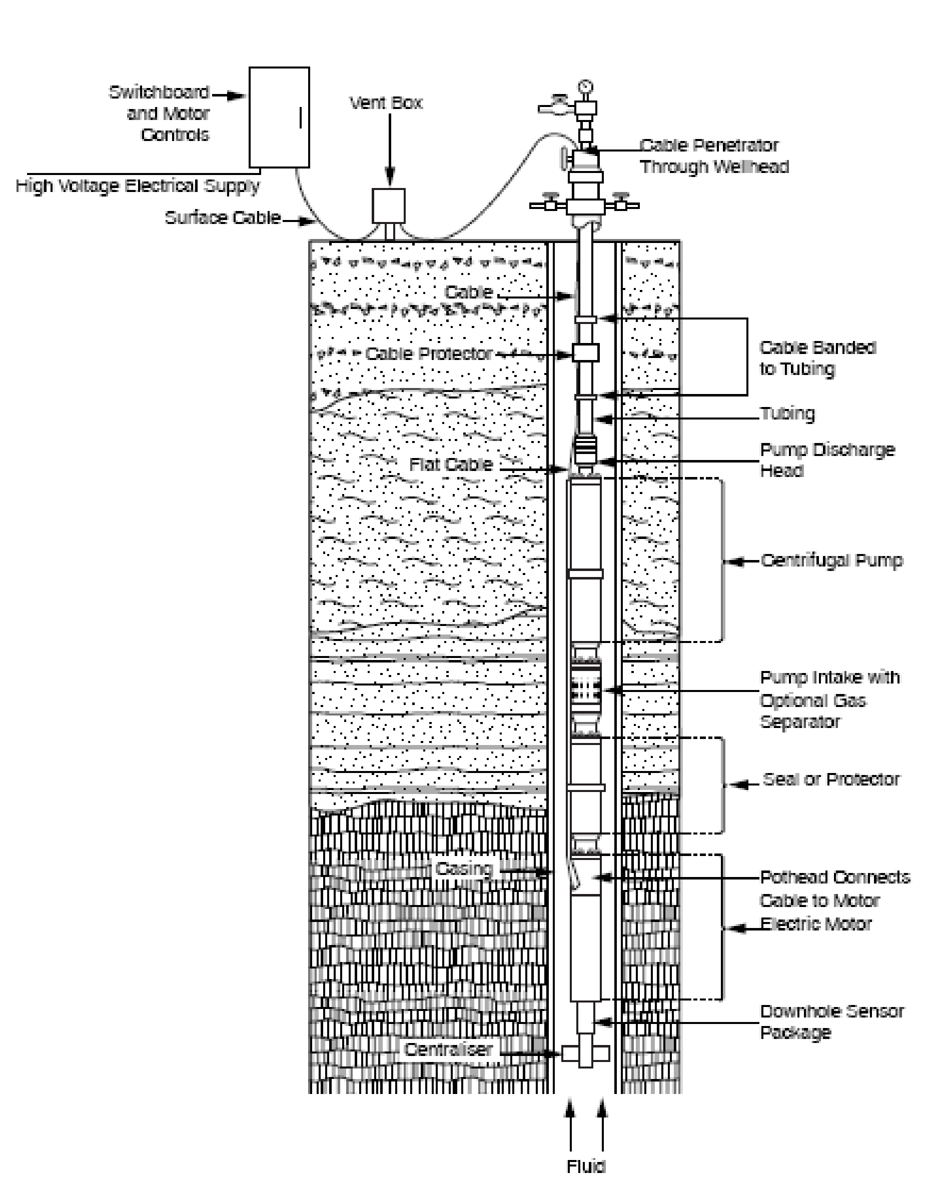
- **Hydraulic Piston Pump**: This uses high pressure power fluid to drive a downhole turbine pump.
- **Jet Pump**: This uses high pressure flow through a venturi or jet, creating a low pressure which produces an increased drawdown and inflow from the reservoir



Electric Submersible Pump (ESP)
(A Dynamic Centrifugal Pump)

ESP employs a downhole centrifugal pump driven by a three phase electric motor. The electric motor is powered via an electric cable that runs from the surface, on the outside of the tubing.

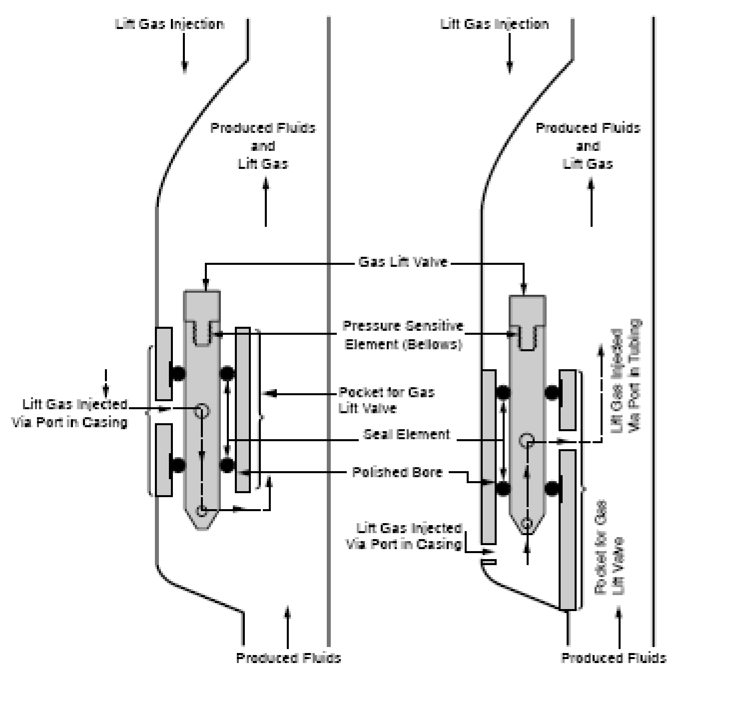


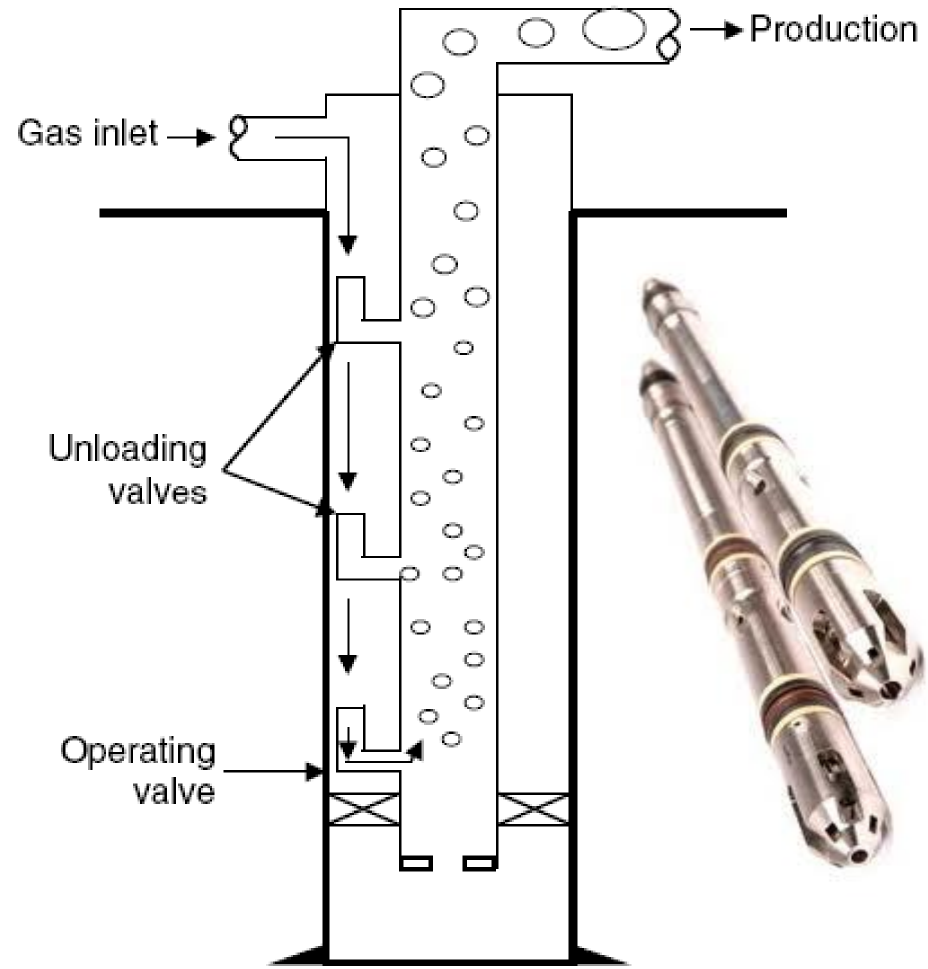


Gas Lift Systems

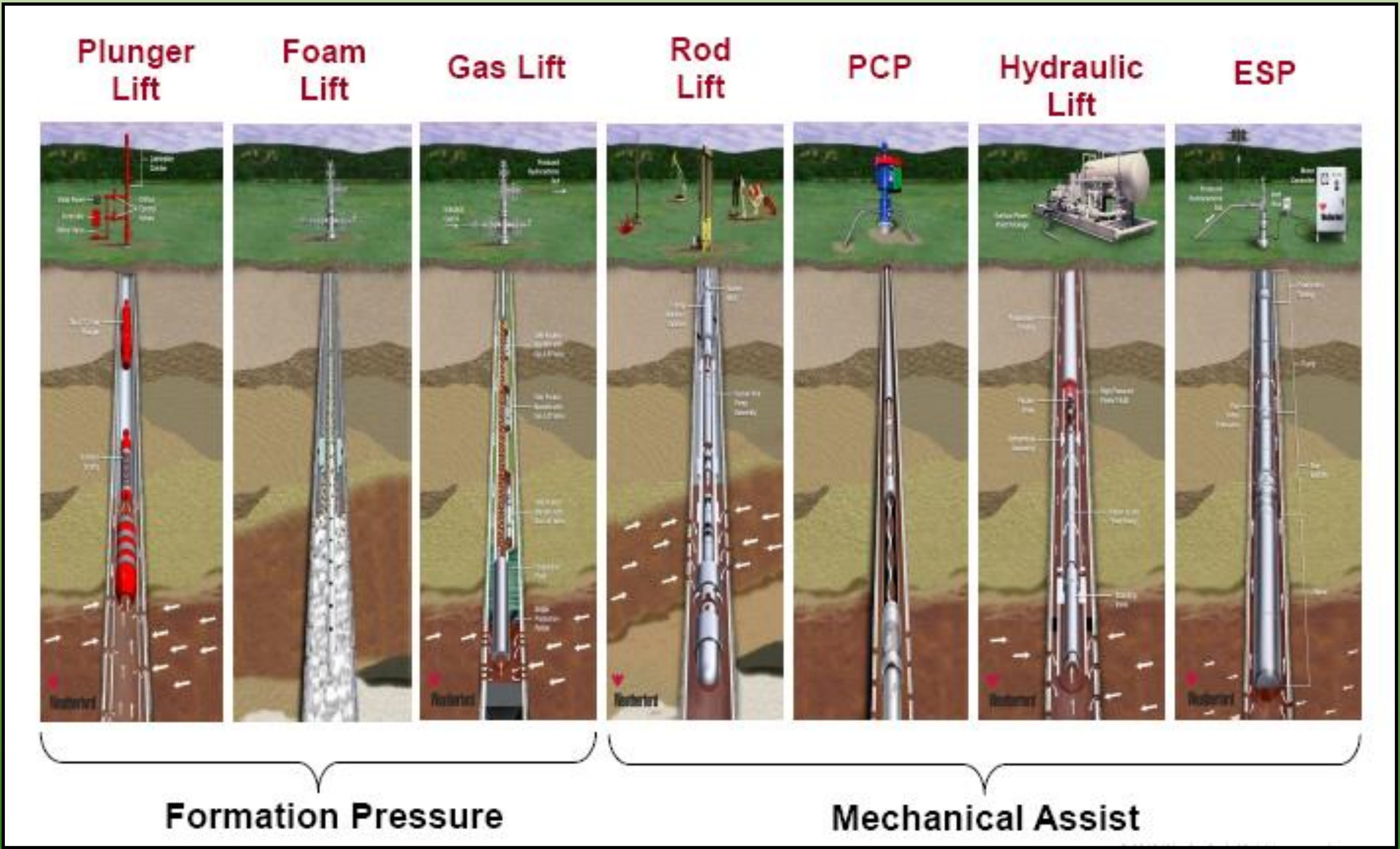
Gas lifts falls in two categories, **Continuous** and **Intermittent**
Gas Lift Systems

In gas lift, high pressured gas is supplied to the casing/tubing annulus and the gas is injected into the tubing string through specially designed gas valves, positioned in the mandrels on the tubing. The injected gas lessens the density of the hydrostatic fluid column.

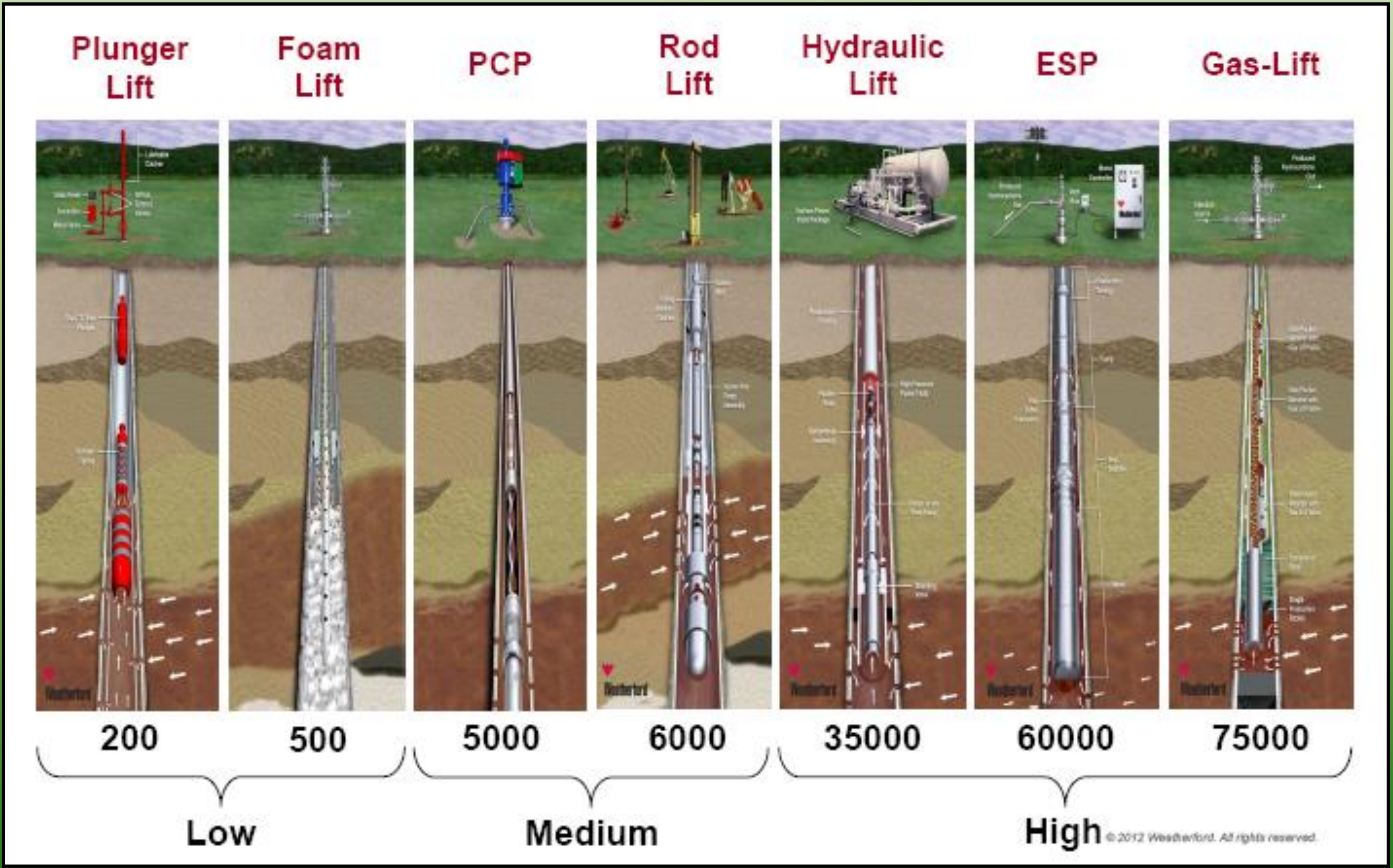




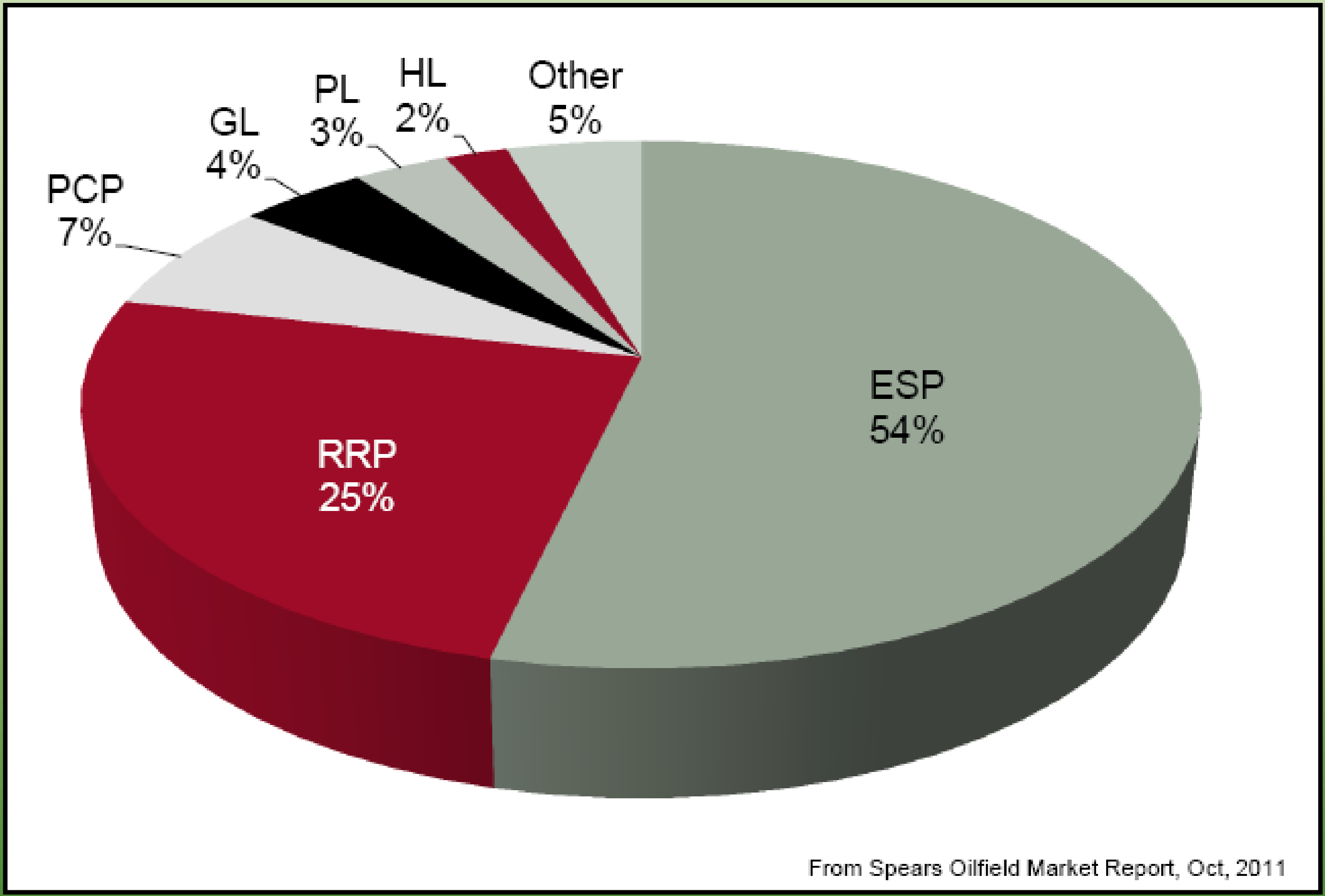
Lift Technology By Energy Source



Lift Technology By Lift Capacity



Artificial Lift Market Share by Type Based on Dollars Spent



ESP- Electrical Submersible Pump
RRP= Sucker Rod Pump
PCP= Progressive Cavity Pump
GL= Gas Lift
PL = Plunger Lift
HL = Hydraulic Lift

Design and Selection Considerations

- Design and Selection
  - Reservoir and Well Deliverability
  - Surface Piping and Treatment Facility
  - Environmental Constraints
  - Operational Constraints
  - Economics

Reservoir and Well Deliverability

- Reservoir Characteristics Like;
  - Deliverability of the reservoir-This is the well's inflow performance (IPR) which represents the ability of the well to produce fluid.
  - Properties and nature of produced fluids
  - Liquid Productive Capacity of the Well
  - Gas Production Expected from the Well
  - Long term recovery plan

- Well Characteristics Like;
  - Well Inflow characteristics
  - Formation depth and dogleg limitations and Effective Lift
  - Production Casing size
  - Annular and tubing safety system
  - Hole Characteristics
  - Completion Type

Location and Environmental Constraints

- Offshore or Onshore locations- This will determine the space constraints and what is possible on location, for example Sucker rod pumps would not be feasible offshore.
- Urban Center or remote locations
- Climatic and Weather Extremes
- Distance from wellhead to processing facilities: This is determine the design well head pressure.
- Power source: What power source is available? Diesel, Natural gas, solar etc. to power the ALS.

Surface Piping and Treatment Facility

- The surface treatment facility in place would affect the type of ALS to be selected. This consideration on the following;
  - flow-line,
  - flow-line restrictions such as chokes, safety valves
  - separator,
  - artificial lift mechanism

Operational Constraints

- Operating Problems such as solids, formation fines. Some ALS are more tolerant of solids than others.

- Choice of ALS material will depend on the operating conditions of;
  - Bottom hole temperature,
  - Corrosive fluids
  - Extent of solid production
  - Production rate

- Automation: Will the system be automated once installed e.g. Intelligent Wells and Smart fields

- Operating Personnel: Is there capable manpower to run and operate the ALS

- Service Availability- Availability of ALS maintenance service provider in area.

- Available Power Source: This will limit the type of engine that the ALS system can have.

Economics

- CAPEX (Capital Expense)- This is the initial acquisition and installation cost of the ALS. Centralized or standalone system.
- OPEX (Operating Expense) – This is the cost that would be incurred in the daily running of the ALS. Costs here include, fuel, servicing, replacements parts etc. Its best to choose a system with low OPEX.
- Personnel Training Costs
- Repair and Replacement Costs
- Economy of scale: Number of wells in the field with same system may give better project economics..
- Reliability

Long Term Reservoir Performance and Facility Constraints

- Production engineers are sometimes faced with the question; how big a ALS should I design for? Should I design for immediate production or design for future production rates. An ALS can be under-designed or overdesigned for fluid and well conditions.

- Hence a good projection of future production profile must be taken into considerations when carrying out a ALS design.

A Comparison Table Showing the Relative Strength of Artificial Lift Systems

	Gas Lift	Foam Lift	Plunger	Rod Lift	PCP	ESP	Hyd Jet	Hyd Piston
Max Depth	18,000 ft *5,486 m*	22,000 ft *6,705 m*	19,000 ft *5,791 m*	16,000 ft *4,878 m*	8,600 ft *2,621 m*	15,000 ft *4,572 m*	20,000 ft *6,100 m*	17,000 ft *5,182 m*
Max Volume	75,000 bpd 12,000 M^3/D	500 bpd 80 M^3/D	200 bpd 32 M^3/D	6,000 bpd 950 M^3/D	5,000 bpd 790 M^3/D	60,000 bpd 9,500 M^3/D	35,000 5,560 M^3/D	8,000 bpd 1,270 M^3/D
Max Temp	450°F 232°C	400°F 204°C	550°F 288°C	550°F 288°C	250°F 121°C	482°F 250°C	550°F 288°C	550°F 288°C
Corrosion Handling	Good to excellent	Excellent	Excellent	Good to Excellent	Fair	Good	Excellent	Good
Gas Handling	Excellent	Excellent	Excellent	Fair to good	Good	Fair	Good	Fair
Solids Handling	Good	Good	Fair	Fair to good	Excellent	sand<40ppm	Good	Fair
Fluid Gravity (°API)	>15°	>8°	>15°	>8°	8°<API<40°	Viscosity <400 cp	≥6°	>8°
Servicing	Wireline or workover rig	Capillary unit	Wellhead catcher or wireline	Workover or pulling rig	Wireline or workover rig		Hydraulic or wireline	
Prime Mover	Compressor	Well natural energy		Gas or electric		Electric	Gas or electric	
Offshore	Excellent	Good	N/A	Limited	Limited	Excellent	Excellent	Good
System Efficiency	10% to 30%	N/A	N/A	45% to 60%	50% to 75%	35% to 60%	10% to 30%	45% to 55%

A Comparison Table Showing the Relative Strength of Artificial Lift Systems

Form of lift	Rod Lift	PCP	Gas Lift	Plunger Lift	Hydraulic Lift	Hydraulic Jet	ESP	Capillary Technologies
Maximum operating depth, TVD (ft/*m*)	16,000 *4,878*	12,000 *3,658*	18,000 *4,572*	19,000 *5,791*	17,000 *5,182*	15,000 *4,572*	15,000 *4,572*	22,000 *6,705*
Maximum operating volume (BFPD)	6,000	4,500	50,000	200	8,000	20,000	60,000	500
Maximum operating temperature (°F/°C)	550° *288°*	250° *121°*	450° *232°*	550° *288°*	550° *288°*	550° *288°*	400° *204°*	400° *204°*
Corrosion handling	Good to excellent	Fair	Good to excellent	Excellent	Good	Excellent	Good	Excellent
Gas handling	Fair to good	Good	Excellent	Excellent	Fair	Good	Fair	Excellent
Solids handling	Fair to good	Excellent	Good	Fair	Fair	Good	Fair	Good
Fluid gravity (°API)	>8°	<40°	>15°	>15°	>8°	>8°	>10°	>8°
Servicing	Workover or pulling rig		Wireline or workover rig	Wellhead catcher or wireline	Hydraulic or wireline		Workover or pulling rig	Capillary unit
Prime mover	Gas or electric	Gas or electric	Compressor	Well's natural energy	Multicylinder or electric	Multicylinder or electric	Electric motor	Well's natural energy
Offshore application	Limited	Limited	Excellent	N/A	Good	Excellent	Excellent	Good
System efficiency	45% to 60%	50% to 75%	10% to 30%	N/A	45% to 55%	10% to 30%	35% to 60%	N/A

Table 1: Relative Advantages of Artificial Lift Systems (After K. E. Brown, JPT, Oct., 1982)

Rod Pumping	Hydraulic Piston Pumping	Electric Submersible Pumping	Gas Lift	Hydraulic Jet Pump	Plunger lift	Progressive Cavity Pumps
Relatively simple system design	Not so depth limited-can lift large volumes from great depths	Can lift extremely high volumes, 20,000 B/D (19078 m^3/d), in shallow wells with large casing.	Can handle large volume of solids with minor problems.	Retrievable without pulling tubing.	Retrievable without pulling tubing.	Some types are retrievable with rods
Units easily changed to other wells with minimum cost	500 B/D (79.49 m^3/d) from 15,000 ft. (4572 m) have been installed to 18,000 ft. (5486.4 m)	Currently lifting ± 120,000 B/D (19068 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.	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.	Moderate Cost
Efficient, simple and easy for field people to operate.	Crooked holes present minimal problems.	Unobtrusive in urban locations.	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.	Low Profile
Applicable to slim holes and multiple completions.	Unobtrusive in urban locations.	Simple to operate.	Unobtrusive in urban locations.	Unobtrusive in urban locations.	Applicable for high gas oil ratio wells.	Can use downhole electric motors that handle sand and viscous fluid well
Can pump a well down to very low pressure (depth and rate dependent).	Power source can be remotely located.	Easy to install downhole pressure sensor for telemetering pressure to surface via cable.	Power source can be remotely located.	Applicable offshore.	Can be used in conjunction with intermittent gas lift.	High electrical efficiency
System usually is naturally vented for gas separation and fluid level soundings.	Analyzable.	Crooked hole present no problem.	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.	Flexible-can usually match displacement to well's capability as well declines.	Applicable offshore.	Lifting gassy wells is no problem.	Power fluid does not have to be so clean as for hydraulic piston pumping.		
Analyzable.	Can use gas or electricity as power source.	Corrosion and scale treatment easy to perform.	Sometimes serviceable with wireline unit.	Corrosion scale emulsion treatment easy to perform.		
Can lift high-temperature and viscous oils.	Downhole pumps can be circulated out in free systems.	Availability in different size.	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.	Can pump a well down to fairly low pressure.	Lifting cost for high volumes generally very low.	Corrosion is not usually as adverse.			
Corrosion and scale treatments easy to perform.	Applicable to multiple completion's.		Applicable offshore.			
Applicable to pump off control if electrified.	Applicable offshore.					
Availability of different sizes.	Closed system will combat corrosion.					
Hollow sucker rods are available for slim hole completion's and ease of inhibitor treatment.	Easy to pump in cycles by time clock.					
Have pumps with double valving that pump on both upstroke and downstroke.	Adjustable gear box for Triplex offers more flexibility.					
	Mixing power fluid with waxy or viscous crudes can reduce viscosity.					

Table 2: Relative Disadvantages of Artificial Lift Systems

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

References

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- Heriot Watt University, Production Technology Course Notes
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