Introduction to Artificial Lift Methods

As covered in the following modules:
Gas Lift and ESP Pump Core
Rod, PCP, Jet Pumps, and Plunger Lift Core

Learning Objectives

This section will cover the following learning objectives:

- Identify the most common artificial lift technologies employed by petroleum engineering operations to exploit and maximize hydrocarbon recovery
- Understand how and why wells, which initially produce under naturally flowing conditions, must ultimately be mechanically assisted to produce major volumes of remaining reserves
- Recognize the engineering design and operations characteristics of: beam pump systems, gas lift systems, electrical submersible pump systems, progressing cavity pump systems, and plunger lift systems
Well Pressure Terminology

\[ P_{\text{res}} \] – reservoir pressure

\[ P_{\text{wf}} \] – flowing bottom hole pressure

\[ P_{\text{ftp}} \] – surface pressure

\[ P_{\text{sep}} \] – separator inlet pressure

\[ (P_{\text{res}} - P_{\text{wf}}) \] is referred to as “drawdown”
Nodal Analysis principles illustrate how flow from the reservoir to the well is observed, measured, and managed by various test methods.

The data above illustrates one method to quantify how reservoir energy provides flow rate into a well as a \( f(P_{\text{res}} - P_{\text{wf}}) \).

The data below illustrates another method to quantify how reservoir energy provides flow rate to a well as a \( f(P_{\text{res}} - P_{\text{wf}}) \).

What is different?
Two different cases, “A” & “B”, based upon conditions at the chosen node $P_{wf}$ with regard to fluid Bubble Point pressure.

Nodal Analysis principles also illustrate how flow to the surface in tubing is observed, measured, and managed.

The curve above illustrates a specific size of tubing and the bottom hole pressure ($P_{wf}$) under specific conditions.
To create the tubing curve, or Outflow data, $P_{wf}$ is the pressure at the base of the tubing string that is available to deliver all of the reservoir fluids—oil, gas, condensate, and water—to the surface and possibly through the choke and flowline to the separator.

$P_{wf}$ is also simultaneously working with the reservoir to create the Inflow curve.

Combining the reservoir and tubing pressure requirements of a producing zone establishes a "well performance" or nodal analysis model. Another term for nodal analysis is "system analysis."

Thus, for a specific amount of reservoir energy and specific tubing size, an equilibrium for rate $Q$ and $P_{wf}$ results.
Artificial Lift provides the opportunity to recover remaining reserves when there is no further intersection of well inflow performance and tubing string performance curves.

Reservoir energy has depleted and the capacity of the tubing in place is too great for the remaining reservoir energy.

For a gas well where reservoir pressure has dropped and water invasion has occurred...

...the identical parallel story for gas reservoir depletion will also be presented.

Reservoir energy has depleted and the capacity of the tubing in place is too great for the remaining reservoir energy.
Artificial Lift Type Selection

1. So, what is the best process for selecting the most appropriate artificial lift completion type for an oil reservoir well?

2. And, how can gas wells be dewatered after the remaining energy from a gas reservoir is mostly depleted?

Artificial Lift Type Selection – “Defining the Need”

How is artificial lift selection conducted?

- Careful consideration of current and future well conditions is necessary
- Many rules-of-thumb exist and many options to analyze
- There is no single technique that provides a quick and easy answer

- Pre-Planning Data and Engineering Considerations
  - Anticipated well production rate over time (inflow)
  - Anticipated well / zone life
  - Anticipated GOR / GLR over life
  - Anticipated water cut over life
  - Well / zone depth
  - Temperature gradient
  - Casing / tubing restrictions
  - Hole geometry / deviation
  - Power availability (electricity, lift gas, fuel gas, power fluid, etc.)
  - Sand production
  - Scale tendencies, asphaltenes, paraffins
  - Offshore or onshore
  - Costs
  - Other
Three Examples of Artificial Lift Type Variance by Company

Company “A”
- Oil Production From A/L
  - ESP 49%
  - BP 32%
  - PCP 8%
  - Gas Lift 4%
  - Plunger 3% (gas wells de-watered)
  - Hydraulic 2%
  - Other 4%

Company “B”
- Oil Production From A/L
  - Gas Lift 65%
  - BP 20%
  - ESP 13%
  - Jet, Hydraulic Pump & PCP < 2%

Company “C”
- Oil Production From A/L
  - Beam Pumps 82%
  - Gas Lift 10%
  - ESP 4%
  - Hydraulic 2%
  - Other 2%

These three examples reflect the different reservoir and operating conditions that govern the optimum selection of artificial lift completion type.

Though these individual company artificial lift requirements vary significantly, the greatest number of wells on artificial lift worldwide by far employ beam pump completions.

*Note the broad difference in AL types installed*
**Major Types of Artificial Lift Illustrated**

**Selection Guide**
- Low rates: Heavy oil
  - Some sand
  - Low gas
- High rates: Gas supply
  - Offshore production
  - Very low cost
- High viscosity: Power fluid
  - Temp tests
  - High cost
- Very high rates: No sand,
  - Low gas
  - Power source
- No sand:
  - High rates
  - Gas well dewatering
  - Final depletion
  - Very low cost
- Heavy oil:
  - Some sand
  - Low gas
- Gas supply:
  - Offshore production
  - Very low cost
- Power fluid:
  - Temp tests
  - High cost
- Selection Guide for Artificial Lift System Application Matrix

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**Artificial Lift System Application Matrix**

<table>
<thead>
<tr>
<th>Operating Depth (feet)</th>
<th>Operating Volume (Typical, bpd)</th>
<th>Operating Temperature (F)</th>
<th>Corrosion Handling</th>
<th>Gas Handling</th>
<th>Solids Handling</th>
<th>Fluid Gravity (API)</th>
<th>Servicing</th>
<th>Prime Mover</th>
<th>Other Requirements</th>
<th>Offshore Application</th>
<th>Overall System Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-14,000</td>
<td>2,000-4,000</td>
<td>75-250</td>
<td>Good to Excellent</td>
<td>Good</td>
<td>Fair to Good</td>
<td>&gt;8</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Fuel Gas or Electrical Power</td>
<td>Limited</td>
<td>45%-60% *</td>
</tr>
<tr>
<td>2,000-15,000</td>
<td>5,000-10,000</td>
<td>100-250</td>
<td>Good to Excellent</td>
<td>Good</td>
<td>Good</td>
<td>&gt;8</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Fuel Gas or Electrical Power</td>
<td>Good</td>
<td>45%-60% *</td>
</tr>
<tr>
<td>5,000-15,000</td>
<td>10,000-20,000</td>
<td>150-300</td>
<td>Good to Excellent</td>
<td>Excellent</td>
<td>Excellent</td>
<td>&gt;15</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Natural Gas &amp; * Compressed</td>
<td>Excellent</td>
<td>45%-60% *</td>
</tr>
<tr>
<td>7,000-17,000</td>
<td>15,000-30,000</td>
<td>200-500</td>
<td>Good to Excellent</td>
<td>Excellent</td>
<td>Excellent</td>
<td>&gt;15</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Natural Gas &amp; * Compressed</td>
<td>Excellent</td>
<td>45%-60% *</td>
</tr>
<tr>
<td>10,000-20,000</td>
<td>20,000-40,000</td>
<td>300-600</td>
<td>Good to Excellent</td>
<td>Excellent</td>
<td>Excellent</td>
<td>&gt;15</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Fuel Gas or Electrical Power</td>
<td>Excellent</td>
<td>45%-60% *</td>
</tr>
<tr>
<td>15,000-30,000</td>
<td>30,000-60,000</td>
<td>400-900</td>
<td>Good to Excellent</td>
<td>Excellent</td>
<td>Excellent</td>
<td>&gt;15</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Fuel Gas or Electrical Power</td>
<td>Excellent</td>
<td>45%-60% *</td>
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<tr>
<td>20,000-40,000</td>
<td>60,000-120,000</td>
<td>500-1,200</td>
<td>Good to Excellent</td>
<td>Excellent</td>
<td>Excellent</td>
<td>&gt;15</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Fuel Gas or Electrical Power</td>
<td>Excellent</td>
<td>45%-60% *</td>
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<td>30,000-60,000</td>
<td>120,000-240,000</td>
<td>600-2,400</td>
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<td>Excellent</td>
<td>&gt;15</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Fuel Gas or Electrical Power</td>
<td>Excellent</td>
<td>45%-60% *</td>
</tr>
<tr>
<td>40,000-80,000</td>
<td>240,000-480,000</td>
<td>700-3,600</td>
<td>Good to Excellent</td>
<td>Excellent</td>
<td>Excellent</td>
<td>&gt;15</td>
<td>Wellhouse or Pulling Rig</td>
<td>IC Engine or Electric Motor</td>
<td>Fuel Gas or Electrical Power</td>
<td>Excellent</td>
<td>45%-60% *</td>
</tr>
</tbody>
</table>

* PDF of the matrix is available for download in the list of resources in the PetroAcademy activity."
Artificial Lift Selection: Example

Well: An offshore well has the following data available. What artificial lift system is the best choice? Why? What is missing from the data and the matrix below which would further guide selection?

Data: 10,000’ (3048 m) TVD, 950 bfpd (151.04 m³/D)(oil and water), 12% w.c., 200°F (93.3°C) bottom hole temperature, trace H₂S, high salinity formation water, 1000 scf/stb (178.1 m³/m³) GLR, minimal sand production, 32 API, company workover rigs and pulling unit rigs available; electricity available, gas supply available long term, reservoir drive mechanisms well understood.

Learning Objectives

This section has covered the following learning objectives:

- Identify the most common artificial lift technologies employed by petroleum engineering operations to exploit and maximize hydrocarbon recovery
- Understand how and why wells, which initially produce under naturally flowing conditions, must ultimately be mechanically assisted to produce major volumes of remaining reserves
- Recognize the engineering design and operations characteristics of: beam (rod) pump systems, gas lift systems, electrical subsurface pump systems, progressing cavity pump systems, and plunger lift systems

<table>
<thead>
<tr>
<th>Operating Depth (feet)</th>
<th>Operating Temperature (F)</th>
<th>Corrosion Handling</th>
<th>Gas Handling</th>
<th>Lift Handling</th>
<th>Other Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>10,000’ (3048 m) TVD</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>950 bfpd (151.04 m³/D)</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>12% w.c.</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>200°F (93.3°C) bottom hole temperature</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>Trace H₂S</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>High salinity formation water</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>1000 scf/stb (178.1 m³/m³) GLR</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>Minimal sand production</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>32 API</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
<tr>
<td>Company workover rigs and pulling unit rigs available; electricity available, gas supply available long term, reservoir drive mechanisms well understood</td>
<td>37.8–287.8ºC (178.6–400°F)</td>
<td>Good</td>
<td>Good</td>
<td>Good</td>
<td>Fuel Gas on Electrical Power</td>
</tr>
</tbody>
</table>

* PDF of the matrix is available for download in the list of resources in the PetroAcademy activity
Why This Module is Important

- Proper artificial lift selection, design, implementation, and operation for producing well completions are critical factors in achieving both optimum production rate control over time as well as maximizing ultimate recovery over the life of a well's completion history.
Why This Module is Important

- Rod pumps dominate the oilfield with regard to the total number of units operating worldwide.
- Rod pumps have proven their durability and competitive and technical superiority over time.

Why This Module is Important

- All of these conditions result in rod pumps commonly being selected as the artificial lift selection of choice.
- The above conditions described have a much broader scope of why rod pumps may be the best choice of artificial lift completion for all or just certain wells in a field.

- Low productivity
- Significant water cut
- Low gas liquid ratio
- Some sand production
- High viscosity fluid production
- Parrafin wax present
- Corrosive conditions mitigated by metallurgical and chemical treatment programs
Why This Module is Important

- **Progressing cavity pump (PCP)** artificial lift has a set of conditions which favor the use of why PCP pumps are chosen.
  - PCP pumps do an excellent job of handling high viscosity heavy crude with moderate sand production from wells of significant depth [e.g. 6000 ft (1828.1 m)]
  - Canadian heavy oil production operators rely upon PCP technology in high temperature thermal recovery operations that PCP pump systems support

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Why This Module is Important

- Jet pump completions are a unique artificial lift application
- Jet pumps are often considered to be the most versatile artificial lift type
- The costliest type of artificial lift application and they are often challenging to operate
Why This Module is Important

- **Bernoulli’s effect** that blends what is referred to as the jet pump “power fluid”, pumped downhole at high pressure, to combine with produced fluids and flowed to the surface.
- What follows at the surface is a separation process to separate produced oil and water from the “power fluid”.

Why This Module is Important

- It permits the recovery of gas reservoir remaining reserves down to reservoir depletion pressure.
- Properly operating plunger lift systems operate at very low cost levels.
Why This Module is Important

- Well and reservoir characteristics and conditions dictate what technology works well and what does not perform well.

- Reservoir Model
- Geological Model
- Artificial Lift Attributes
Rod, PCP, Jet Pumps and Plunger Lift Core

Rod Pumps

Learning Objectives

This section will cover the following learning objectives:

- Recognize various rod pump types based upon the prime mover and surface unit and how they combine to actuate the pump’s rod string
- Identify rod pump components and terminology
- Understand the mechanical operation of a rod pump
- Recognize common rod pump failures
- Understand conventional reservoir applications
Rod Pump Surface Unit Types

- The function of the sucker rod pumping system is to transmit power to the downhole pump in order to lift reservoir fluids to the surface.
- The sucker rod pump lowers the bottomhole pressure.
- The pressure difference between the formation and the wellbore allows fluid to flow into the well and be pumped to the surface.

Conventional Unit

Mark Unit

Air Balance Unit

- All three units shown here are often referred to as a “beam” pumps due to surface geometry
- The Conventional Unit surface geometry is the most common type industry rod pump, followed by the Mark II and Air Balance types.
The most common rod pump surface unit type is the Conventional “beam pump” design.

Mark II Unit Rod Pump Design

- Compare the Mark II rod pump design to the conventional design. It has a different surface unit geometry when viewing the “crank arm” component as shown below.
The Mark II rod pump design is the second most common type rod pump unit. Its unique geometry will be explained shortly.

These rod pump types are much less common than the beam pump type.
Smaller Hydraulically Powered Rod Pump Units

- Often used for coal bed methane wells and other applications
- Economizer type has no observed surface motion
- All of these 5 type variations typically require more regular surface maintenance than standard rod pump types
- These rod pump types are much less common than the beam pump type

Rod Pump Components Terminology

- **Surface Equipment**
  - Units
  - Wellhead
  - Polished Rods
  - Motors
  - Gearbox
  - Sheaves
  - Belts
  - Transformers
Rod Pump Components Terminology

- **Downhole Equipment**
  - Well Tubing
  - Rods
  - Pump

The Rod Pump Surface Unit Actuates a Rod String

Rod String and Connections

- Coupling
- Wrench Flats
- Sucker Rod Body
- Wrench Square Identification

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Rod Pump Rods are Often Called Sucker Rods

- Rods are most commonly steel
  - Various steel grades
  - Often chemical inhibition is necessary

- Lightweight fiberglass rods also are used
  - Corrosion resistant
  - Proper design critical

The Rod Pump Rods Actuate the Downhole Pump

- Tubing pump barrel part of the tubing wall
- Insert pump run in well on wireline or rods
Down Hole Pump Upstroke & Downstroke Performance

Sucker Rod Pump Cycle

- Gearbox converts low torque, high rpm motor motion to high torque, low rpm motor motion
  - Counterweights help reduce torque that the gear box must supply
- Crank arm connects the gearbox to the counter-weight

Rod Pump Gear Box, Crank Arm, and Counterweight
**Rod Pump Counterweight**

- Releases energy to the gearbox on the upstroke while falling
  - Helps the gearbox during upstroke when rod load is greatest
- Stores energy on the downstroke by rising
  - On the downstroke, the rod load helps the gearbox lift the counterweight to the top position to release energy again

**Mark II Unit Rod Pump Offset Crank Angle**

- The Mark II unit offset (195° vs 180°) crank geometry effectively reduces rod acceleration at the beginning of the upstroke when load is greatest, thereby effecting a reduction in the polished rod load
Mark II Unit Rod Pump Offset Crank Angle

- The maximum upstroke torque required (when lifting rods and fluid load) is reduced and the maximum downstroke torque (lowering rod load in fluid back into the well) is increased.

Rod Pump Data Gathering / Design and Operation

- **Dynamometer**
  - A “strain gauge” that measures loads on the polished rod at the surface.
  - Loads on the rod string as a function of the position of the rod string reciprocation and position of the beam are continuously measured for analysis.
**Dynamometer**

- A "strain gauge" that measures loads on the polished rod at the surface.
- Loads on the rod string as a function of the position of the rod string reciprocation and position of the beam are continuously measured for analysis.

Engineers use computer programs to convert the surface dyno data acquired to determine the load on the downhole pump to optimize the design.
Conventional Rod Pump Applications

Multiple Zone Low Rate Completions

- Two-in-One
  - > 2 zones
  - 1 well

- Three-in-One
  - > 3 zones
  - 1 well

Unconventional Rod Pump Application

- Plug & perf or ball & sleeve shale oil frac tool completions with rod pump artificial lift

![Diagram of unconventional rod pump application](https://via.placeholder.com/150?text=Diagram)
Rod String & Tubing Failures

- Rod failure due to corrosion is most common
- Rod coupling wear also common
- Tubing failure also common in hole dog leg sections

Rod Pump Basics Summary

**Advantages**

- Good for high viscosity, low API gravity oil
- Low operating costs if designed and operated properly
- Simple to operate and understand (design is challenging)
- Controllers are used to eliminate pump-off conditions
- Common for high water cut, low net oil applications
- Can handle some sand production

**Disadvantages**

- Production rates generally low (compared to ESP, gas lift, others)
- Gas occupies pump space; efficiency reduced
- Large surface equipment
- Rod / tubing wear problems most serious concern
Learning Objectives

This section has covered the following learning objectives:

✓ Recognize various rod pump types based upon the prime mover and surface unit and how they combine to actuate the pump’s rod string
✓ Identify rod pump components and terminology
✓ Understand the mechanical operation of a rod pump
✓ Recognize common rod pump failures
✓ Understand conventional reservoir applications
Learning Objectives

This section will cover the following learning objectives:

- Identify the primary rotor and stator components of a progressing cavity pump and the importance of proper elastomer choice for given well conditions
- Understand the principles involved in specifying / selecting PCP equipment to accommodate high temperature, high viscosity, low API gravity, solids, and similar environmental conditions which PCP units tolerate
- Recognize the characteristics of maximum well depth and rate for which PCP units are acceptable
Progressing Cavity Pump

- PCP Pump Completion Applications
  - Heavy oil
  - Stripper well rates
  - Varying inflow
  - High water cut
  - Gas well dewatering

Rotor (Steel Rod) and Stator (Elastomer)

- Sealed cavities progress uphole from the suction location to the discharge location
- Fluid flow rate is directly proportional to the rotational speed of the rotor
PCP Pump Operation

- Note pockets of well fluids and formation particles progressively moving uphole by means of a helical screw (rotor) inside a helical pocket (stator).
- Rotor is driven by beam pump rods turned at the surface by an electric motor or by downhole ESP type motor.

Wide Range of Stator Elastomers

- **Standard nitrile**
  - Good oil and solvent resistance
  - Excellent abrasive resistance

- **Soft nitrile**
  - Fair oil and solvent resistance
  - Excellent abrasive resistance

- **High nitrile**
  - Excellent oil and solvent resistance
  - Good abrasive resistance

- **Hydrogenated nitrile**
  - Excellent oil and solvent resistance
  - Good abrasive resistance
  - Good H₂S resistance

Four Different Rotor / Stator Mechanical Designs

Any of the nitrile elastomers may be chosen based on well conditions.
Rotor Failures From Sand or Poor Adjustment

- High Torque
- Excessive Torque
- Sand
- Poor Pump Set Up Adjustments

PCP System Tubing Wear Causes

- Rotational rod movement and resultant wear inside tubing
- Harmonic oscillation of rods inside tubing
- Abrasive fluids produce fluids that are corrosive
- Deviated wells intensify side load wear
PCP Rod Guides to Minimize Wear

Rotating Rod Coupling  Spin-Thru® Rod Guide  Field-Applied Rod Guide

Centralizing PCP rods minimizes wear by using guides

PCP Pump Capacities as Function of Depth

PC Pump Design Criteria

Source: Monflo Halliburton
PCP Pump Attributes

Progressing Cavity Pumps

- Many general uses of PCP pump per Moyno web site
  - Positive displacement
  - Non-pulsating
  - Accurate, repeatable flow
  - Low shear
  - Temperature range to 350°F (176.7°C)
  - Viscosities to 1,000,000 cps (1 000 000 mPa/s)
  - Pressures to 1,000 psi (6894.8 kPa); capacities to 2,500 gpm (9.5 m³/min)
  - Can handle particles to 2.8 in. in diameter (0.07 m)

- Typical general industry applications
  - Raw sewage and sludge
  - Paper mill wastewater and coatings
  - Food, wastes and by-products
  - Chemical feed and metering
  - Viscous and abrasive building materials
  - Abrasive crudes
  - Very popular in Canada where there are many shallow wells and highly viscous, sandy crude

PCP Pump Advantages and Disadvantages

Progressing Cavity Pumps

Advantages
- Highly tolerant of solids
- Suitable for heavy, viscous crudes with sand
- Tolerant of gas, but efficiency reduced

Disadvantages
- Limited by elastomers to low to medium ΔP
- Limited by elastomers to crude API < 34˚ (> 34˚ causes excessive elastomer swelling)
- Rod string driven pump is limited to shallow [< 3000 ft (914.4 m)] applications due to torque and wear of rod system
PC Pump and Rod Pump Foot Print

Comparison of Above Ground Surface Facilities

Downhole PC Pump

Beam Pump

Learning Objectives

This section has covered the following learning objectives:

- Identify the primary rotor and stator components of a progressing cavity pump and the importance of proper elastomer choice for given well conditions
- Understand the principles involved in specifying / selecting PCP equipment to accommodate high temperature, high viscosity, low API° gravity, solids, and similar environmental conditions which PCP units tolerate
- Recognize the characteristics of maximum well depth and rate for which PCP units are acceptable
Learning Objectives

This section will cover the following learning objectives:

✔ Understand Bernoulli's Principle and the physics of how jet pumps function
✔ Recognize the attributes of jet pump technology, the relative high cost of jet pumps compared to other artificial lift systems, and their flexibility
✔ Understand the concept of a “power fluid” to operate a jet pump
Bernoulli’s Principle and Jet Pumps

- **Jet Pumps**
  - In a jet pump, it is this vacuum developed in the pump which bring fluids into the pump downhole.

- **Bernoulli’s Principle**
  - The Venturi Effect is an example of Bernoulli’s Principle which states that when a fluid flows through a pipe and encounters a reduced diameter (a constriction or nozzle), the fluid velocity increases in the restriction, reducing pressure and producing a vacuum, known as the Bernoulli Effect.

How a Jet Pump Works

- **Jet Pump Principle**
  - Apply a “Venturi effect” to lower the pressure at the bottom of a jet pump well completion
  - Create the “Venturi effect” by pumping large quantities of power fluid (2 to 4 times the well’s produced rate fluid volume) downhole at high pressure
  - Pump a “power fluid” of either lease crude or water downhole
How a Jet Pump Works

Jet pumps operate on the principle of a high-pressure fluid jet and the Venturi effect it creates.

1. Jet pumps use a surface pump to drive power fluid down the tubing installed in the well bore.

2. As the fluid passes through the nozzles in the jet pump, the Venturi effect vacuum pulls in the wellbore fluids which are mixed with the power fluid.

3. Mixed well fluid and power fluid is transported under pressure to the surface, usually up the well casing or a separate production string.

4. A surface separator processes the processed well fluid mixed with the power fluid.

5. Fluids and solids are removed and the separated power fluid is reused in a closed loop process.

Power Fluid is Pumped Down Hole and the Returned Fluid is Separated.
Jet Pump Surface Facilities

Jet Pump Use of Power Fluid

- Surface separator to process well fluid mixed with the system's power fluid
- Fluids and solids are removed
- Separated power fluid is reused in a closed loop process

Jet Pump Attributes

Artificial Lift Completion Comparison

<table>
<thead>
<tr>
<th>Operating Conditions</th>
<th>Beam</th>
<th>ESP</th>
<th>Gas Lift</th>
<th>Jet</th>
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<td>Sand</td>
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<td>Poor</td>
<td>Good</td>
<td>Good</td>
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<tr>
<td>Paraffin</td>
<td>Poor</td>
<td>Good</td>
<td>Fair</td>
<td>Good</td>
</tr>
<tr>
<td>High GOR</td>
<td>Poor</td>
<td>Fair</td>
<td>Excellent</td>
<td>Good</td>
</tr>
<tr>
<td>Deviated hole</td>
<td>Poor</td>
<td>Fair</td>
<td>Good</td>
<td>Good</td>
</tr>
<tr>
<td>Corrosion</td>
<td>Good</td>
<td>Fair</td>
<td>Fair</td>
<td>Good</td>
</tr>
<tr>
<td>High volume</td>
<td>Poor</td>
<td>Excellent</td>
<td>Good</td>
<td>Good</td>
</tr>
<tr>
<td>Depth</td>
<td>Fair</td>
<td>Fair</td>
<td>Fair</td>
<td>Excellent</td>
</tr>
<tr>
<td>Scale</td>
<td>Good</td>
<td>Poor</td>
<td>Fair</td>
<td>Good</td>
</tr>
<tr>
<td>Flexibility volume</td>
<td>Fair</td>
<td>Poor</td>
<td>Fair</td>
<td>Good</td>
</tr>
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- Jet pumps compare well to other Artificial Lift systems in deep wells
- Jet pump technology is the singular most flexible method of artificial lift
- Jet pumps are as efficient as ESPs in production ranges up to one thousand bfpd
- However, jet pumps are, by far, the most costly Artificial Lift system
- Safety and environmental concerns must be assessed

From: Central Hydraulics Co.
### Jet Pump Advantages and Disadvantages

#### Advantages
- Can be run on wireline or pumped in & out of well
- Good for installations without much infrastructure (exploratory well tests)
- Can handle fair amounts of sand and gas
- Can handle viscous crudes if supply of light crude for power fluid / diluent available

#### Disadvantages
- High pressure power fluid pumped around the field create:
  - Safety issues
  - Environmental concerns
  - Cost of flow line issues
- Power fluid treating / reconditioning facilities
- Mixing of production with power fluid makes it difficult to measure production accurately

### Learning Objectives

This section has covered the following learning objectives:

- Understand Bernoulli’s Principle and the physics of how jet pumps function
- Recognize the attributes of jet pump technology, the relative high cost of jet pumps compared to other artificial lift systems, and their flexibility
- Understand the concept of a “power fluid” to operate a jet pump
Learning Objectives

This section will cover the following learning objectives:

- Identify the surface and downhole equipment which comprise plunger lift completions designed to unload low pressure, mostly depleted gas wells.
- Understand the principles of plunger cycling using only remaining reservoir pressure to periodically lift water off a formation to permit maximum drawdown and gas recovery.
- Understand the principles of Beeson chart design to determine whether candidate gas wells are qualified for completion as plunger lifted wells.
**Plunger Lift**

**Plunger Lift System Components**

- Unloads fluids from low energy wells
- Plunger travels to well bottom and “swabs” fluid to the surface
- Continual removal of wellbore fluids reduces BHP
- System operates on continuous cycle

**Typical Plunger Lift Well**
Low Pressure Gas Wells and High GLR Oil Wells

- Plunger Lift Operation
  - Utilizes formation gas
  - Plunger “travels” tubing string
  - Gas pressure build up provides lift
  - Plunger lifts slugs (oil, water, etc.)
  - Plunger “cycles”
  - No external energy input to system
  - Controller system uses pressure

Plunger Pump Systems Components
Various Plunger Designs

1. Pad Plunger
2. Brush Plunger
3. Bypass Plunger
4. Turbo (sand)
5. Turbulent Seal
6. Brush
7. Turbulent Seal
8. Bypass Plunger
9. Turbulent Seal

Plunger Lift Operation: Engineering Detail

The plunger in the system is the device that freely travels from the bottom of the well to the surface inside the tubing string periodically lifting well fluids. There are numerous designs of plungers for varying situations. The plunger is used as a mechanical interface between the gas phase and the fluid phase in a well. With the well closed at the surface, the plunger rests at the bottom of the well, on top of the spring assembly. When the well is opened at the surface, with all production being through the tubing, the well begins to flow and the pressure in the tubing decreases. Because the trapped gas in the casing/tubing annulus remains at a higher pressure than the tubing and the differential pressure between the two increases, the fluid level in the annulus decreases as the fluid is pushed downward where it u-tubes into the tubing. The mechanical tolerance between the outside diameter of the plunger and the inside of the tubing leaves sufficient space for the fluid to bypass the plunger, allowing it to remain resting on bottom. When all the fluid in the annulus is on top of the plunger, the stored gas, which is displacing it, U-tubes into the tubing. As this occurs, the expansion properties of gas cause the plunger to move up the tubing string with the fluid load on top. A small amount of gas will bypass the plunger, but this is useful as it scours the tubing wall of fluid, keeping all the fluid on top of the plunger. This small gas blow-by also helps lighten the liquid load on top of the plunger so not as much pressure is required under the plunger for lifting. If the system has been properly engineered, virtually all the fluid can be removed from the well, which allows the well to flow at the lowest bottom hole pressure possible. Production is consequently optimized.
Plunger Lift Design Criteria

2-3/8 in. (0.06 m) TUBING
Beeson Chart
GLR Required for Well Depth as Function of Net Operating Pressure

Net Operating Pressure = (casing pressure – line pressure)

Plunger Lift Design: Candidate Selection Example

2-3/8 in. (0.06 m) TUBING
Beeson Chart
GLR Required for Well Depth as Function of Net Operating Pressure

Net Operating Pressure = (casing pressure – line pressure)

Example:
Net Operating Press  300 psi (2064.8 kPa)
Well Depth         8000 ft (2438.4 m)
> Required GLR    5800 +/- scf/stb (1033 m³/m³)
Plunger Lift Design: Well Kick Off Set Up and Check

**Liquid Load and Plunger Lift Well Start Up**
- Rate of liquid buildup in the well will determine the plunger cycling time
- Liquid load (fluid in tubing) should be minimal before plunger lift start up
- *Load Factor should not exceed 40% / 50% at start up*

\[
\text{Load Factor} = \frac{\text{Shut In Casing Pressure} - \text{Shut In Tubing Pressure}}{\text{Shut In Casing Pressure} - \text{Shut In Line Pressure}} \times 100\%
\]

**Example:**

- Casing Pressure: 600 psi (4136.9 kPa)
- Tubing Pressure: 500 psi (3447.4 kPa)
- Sales Line Pressure: 100 psi (689.5 kPa)

\[
\text{Load Factor} = \frac{(600 - 500)}{(600 - 100)} \times 100\%
\]
\[
\text{Load Factor} = 20\%
\]

**Plunger Lift Operation: Examples**

1. **Gas gradient**
   - 0.20 psi/ft (4.52 kPa/m)
2. **Reservoir depth**
   - 6000 ft / 4-1/2 in. tubing (1828.8 m / 0.11 m)
3. **Sales line pressure**
   - 60 psig (413.69 kPa)
4. **Cycles / day**
   - 1
5. **Gas rate**
   - 5 MCFD (141.58 m³/D)

2. **Gas gradient**
   - 0.25 psi/ft (5.66 kPa/m)
2. **Reservoir depth**
   - 9000 ft (2743.2 m)
3. **Sales line pressure**
   - 50 psig (344.74 kPa)
4. **Gas rate**
   - 36 to 52 MCFD increase (1019.41 to 1472.46 m³/D)

3. **Gas gradient**
   - < 0.10 psi/ft
   - (<2.26 kPa/m)
2. **Reservoir depth**
   - 6500 ft (1981.2 m)
3. **Sales line pressure**
   - 100 psig (689.48 kPa)
4. **Cycles / day**
   - 2
5. **Gas rate**
   - 35 MCFD (991.1 m³/D)
Artificial Lift: Plunger Lift Design

Advantages

- Uses reservoir gas to lift fluids/applicable for high GLR wells
- Can be set up to open and close wells over time cycles
- Good for unloading water off gas well formations
- Keeps tubing free of wax, salt, scale, etc.
- Increases overall recovery by reducing BHP
- No external energy required for lift
- Good for highly deviated wells
- Good for remote wells
- Very low cost

Disadvantages

- Careful mechanical and well set up prior to plunger lift kick off is essential
- SIWHP (shut-in wellhead pressure) should be at least 1.5 times sales line pressure
- Sandy formations cause operating problems
- Requires close initial attention until controller is properly adjusted

Learning Objectives

This section has covered the following learning objectives:

- Identify the surface and downhole equipment which comprise plunger lift completions designed to unload low pressure, mostly depleted gas wells
- Understand the principles of plunger cycling using only remaining reservoir pressure to periodically lift water off a formation to permit maximum drawdown and gas recovery
- Understand the principles of Beeson chart design to determine whether candidate gas wells are qualified for completion as plunger lifted wells
Back to Work Suggestions

**Rod, PCP, Jet Pumps, and Plunger Lift Basics**

Leverage the skills you’ve learned by discussing the skill module objectives with your supervisor to develop a personalized plan to implement on the job. Some suggestions are provided.

**Do you have reliable production data?**

- Meet with a company production engineer or technician in your organization to review various available databases which detail specific reservoir fluids, lithology, well completions, and processing information used to analyze and understand overall production performance parameters.

- Using the databases above, review inflow performance data available to understand overall well rates achieved by your organization’s reservoirs and their current well completions.

- Using the databases above, determine specific reservoir and produced fluid properties throughout the operation for all wells (API gravity, PVT reports, GLR data, paraffin and asphaltene content, salinity, produced sand by zone, etc.). Discuss with design staff how this data is used to pre-qualify well completions for selecting artificial lift system types.
Do you have reliable production data?

☑ Using the databases above, identify the mechanical components of installed and operating Rod Pump, PCP Pump, Jet Pumps, and Plunger Lift artificial lift system types. Identify all the different types of rod pump surface units installed and operating. Study the surface unit and down hole configurations of the artificial lift system completions. Have a facilities engineer explain the jet pump flow stream and surface separation and processing of power fluid used and produced fluids. Distinguish the different plungers run in your plunger lift wells.

Do you have reliable production data?

☑ Using the databases above, review the performance of existing Rod Pump, PCP Pump, Jet Pumps, and Plunger Lift artificial lift systems for oil wells and other Plunger Lift completions for unloading gas wells. Analyze well performance information and identify the details of incremental improvements in performance achieved over time for each type of installed artificial lift type.
Do you have reliable production data?

☑ Accompany a field engineer or technician on routine operations maintenance and data gathering visits to well sites where artificial lift is installed in your organization. Always carry a field book / hand held device to immediately capture and record questions or observations to be later discussed and clarified.

Do you have reliable production data?

☑ Seek to accept responsibility to actively participate in specific problem-solving studies (such as rod string failure analysis, corrosion control practices in place or recommended, power consumption, jet pump cost reduction, plunger lift solar panel set up, and related operational activities conducted within your organization.)
Rod, PCP, Jet Pumps and Plunger Lift Core

PetroAcademy™ Production Operations

- Production Principles Core
- Well Performance and Nodal Analysis Fundamentals
- Onshore Conventional Well Completion Core
- Onshore Unconventional Well Completion Core
- Primary and Remedial Cementing Core
- Perforating Core
- **Rod, PCP, Jet Pump and Plunger Lift Core**
  - Reciprocating Rod Pump Fundamentals
  - Gas Lift and ESP Pump Core
  - Gas Lift Fundamentals
  - ESP Fundamentals
  - Formation Damage and Matrix Stimulation Core
  - Formation Damage and Matrix Acidizing Fundamentals
  - Flow Assurance and Production Chemistry Core
  - Sand Control Core
  - Sand Control Fundamentals
  - Hydraulic Fracturing Core
  - Production Problem Diagnosis Core
  - Production Logging Core
  - Production Logging Fundamentals