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Introduction

New oil wells which naturally flow are produced by managing the drawdown in the well by means of a surface choke. New wells often produce above the bubble point pressure at the reservoir depth. As the reservoir ages and reservoir pressure drops, flow drops until the well must employ an artificial lift system to provide assistance.

Straight Line Inflow Performance Relationship

Single phase flow with the well bottomhole pressure above the bubble point pressure generates a straight line result for flow as a function of Pwf. This behavior is referred to as a well’s productivity index, a constant referred to as the well PI.

The well productivity is illustrated below in Figure 1 for flow above the bubble point pressure at Pwf.

![Figure 1](image)

Curved Line Inflow Performance Relationship

When the flowing bottomhole pressure Pwf is below the bubble point pressure, two phase liquid and gas flow occurs in the reservoir. The well productivity is illustrated below in Figure 2 for flow below the bubble point pressure at Pwf.

This type of performance is typical of a solution gas drive reservoirs. A plot of flowing bottomhole pressure Pwf vs. liquid production rate generates a curved line with a reduction in the inflow performance relationships as the reservoir pressure (Pres) depletes.
Gas Wells

For gas wells, viscosity and compressibility are a function of pressure with inflow characteristics similar to the Vogel IPR above. High gas flow velocities around the wellbore often result in turbulent flow. The resulting non-linear IPR of gas wells is often expressed as:

\[ \text{Pres}^2 - P_{wf}^2 = aq + bq^2 \]

Where: \( aq \) is referred to as laminar flow and \( bq^2 \) is referred to a turbulent flow.

The constants \( a \) and \( b \) are derived from multi-rate well tests or alternatively estimated from known reservoir and gas properties.

Establishing a Well's IPR

The inflow performance relationship for a given well has to be established by a well test. In theory, one production rate with corresponding bottomhole pressure and the shut-in pressure will define the inflow performance relationship. In practice a number of flow rates may be taken to confirm the well performance.

If a sample of formation fluid is taken and analyzed to establish the bubble point pressure, it will be possible to decide whether to use the straight line, the Vogel or the Vogel/Glass inflow performance relationship.
Use of the IPR

The inflow performance relationship is useful as a tool to monitor well performance and predict the stimulation and artificial lift requirements of a number of wells. The IPR for a well must be known in order to size the well tubulars correctly.

Based on interpolation between wells, if the initial IPR for a well is lower than expected in a particular part of the reservoir, it may then be suspected that the formation has been badly damaged during the drilling and completion phase. Mapping the IPRs across the field may highlight this situation.

When wellbore damage is confirmed by a build-up survey the well may require stimulation. Even with stimulation, the inflow performance of a well will decline with falling reservoir pressure. Plotting this decline will indicate approximately when the well will have to be artificially lifted in order to maintain the required offtake rate from the field.

Tubing Selection

The method by which the optimum tubing string is selected for a well involves the calculation of the IPR and the IPC for several different sets of conditions. These are usually as follows:

- IPRs for the expected life of the field, incorporating reservoir pressure decline and changes in the PI.
- IPCs for different tubing sizes, at different GORs, water cuts and/or tubing head pressures, depending on the expected performance of the reservoir.
- Production requirements such as maximizing initial offtake, optimizing production late in field life, etc.

A complete representation of the flowing well is then constructed for each possible set of conditions, and from this the optimum tubing size can be selected, depending on production requirements. An example of a series of IPRs and IPCs for a well is shown in Figure 3.
Artificial Lift

Having selected the optimum tubing size for the well completion, it may be apparent from the IPR and IPC constructions that at some point in the life of the well the reservoir will no longer be able to flow naturally to surface at the required rate. At this point in time, artificial lift will be required in order to maintain production at the required level.

There are six main types of artificial lift mechanism used in the industry, namely:

- Gas Lift
- Beam Pumps
- Electric Submersible Pumps
- Progressing Cavity Pumps
- Plunger Lift
- Hydraulic Pump

Each of these types of artificial lift is discussed briefly in the following sections.
Gas Lift

The technique of increasing the flowing lifetime of the well, or of increasing the production rate above the naturally flowing rate, by injecting gas into the tubing string is known as gas lift.

**Continuous Gas Lift** - Relatively high pressure gas is continuously injected into the casing from where it enters the tubing string through valves located at intervals along the length of the tubing. By virtue of the increased gas content of the fluid column in the tubing, the density of the fluid is reduced and hence the drawdown on the reservoir increased.

**Intermittent Gas Lift** - Gas is injected in a short burst into the casing-tubing annulus, causing a ball valve at the bottom of the tubing to close and pushing a slug of liquid from the bottom of the tubing to surface. The gas supply is then shut off, allowing the well fluids to enter the tubing from the reservoir ready for the next slug.

A schematic diagram of continuous gas lift is shown in Figure 4.

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![Diagram of Gas Lift](image)

*Figure 4*
Continuous gas lift is by far the most common form of gas lift used in the industry.

Continuous gas lift is essentially an extension of natural flow, whereby the producing GOR is artificially increased by the injection of gas. This results in the flowing bottomhole pressure being reduced for a particular rate. For maximum benefit, the gas should be injected as deep as possible, reducing the density of as much of the fluid column as possible. Gas is injected through gas lift valves, a series of which are run in side pocket mandrels together with the tubing string, and so designed that only one valve is open and passing gas at any one time.

It is common practice to utilize the annular space between the casing and the tubing as the conduit for the gas lift gas down to the point of injection. The gas lift valves are such that they allow passage of gas from casing to tubing, but prevent the passage of fluid from tubing to casing.

Continuous gas lift is basically a high rate production method. For a given tubing size, there is a gas/liquid ratio which will result in the lowest intake pressure. This is called the optimum GLR, and it decreases as the production rate increases. Consequently, for low rate production, large quantities of gas are required to obtain the low intake pressures. Hence, continuous gas lift becomes inefficient at low rates and alternative artificial lift techniques are used. Continuous gas lift takes full advantage of the well's natural energy and can handle significant amounts of solid material. The major disadvantage is the inability to reduce the intake pressure to near zero levels, and the need for a high pressure gas supply.

A typical gas lift system comprises of the following components:

- Source of high pressure gas (compressor, gas well etc.)
- Gas distribution lines
- Surface controls
- Subsurface controls (gas lift valves)
- Flow lines Separation equipment
- Storage facilities
Beam Pumping

Another type of artificial lift technique is beam pumping, also called rod pumping or sucker-rod pumping. It is used extensively throughout the industry.

A typical beam pumping system is shown in Figure 5 and consists of the following:

- Power unit
- Pumping unit
- Sucker-rod string
- Subsurface pump

*Figure 5*
The pumping unit is that part of the installation which converts the rotary motion of the power unit to the reciprocal motion required to operate the pump. This motion is transferred to the subsurface pump via sucker rods, which are small diameter steel or fiberglass rods that run inside the tubing string. The subsurface pump is a configuration consisting of a standing valve and a travelling valve, which open and close in sequence with the upstroke and downstroke of the sucker rods. A schematic is shown in Figure #7. During the upstroke, the travelling valve is closed and the standing valve opens, allowing wellbore fluids to enter the tubing string. During the downstroke, the standing valve closes and the travelling valve opens and fluid is forced up the tubing. The cycle is then repeated, bringing the fluid to surface.

The main advantage of the beam pump is that the bottom hole flowing pressure $P_{wf}$ can be drawn down very low, permitting low pressure reservoirs to be produced. The system is also very reliable and economical to operate, once it is set up properly. Beam pumps do exhibit a large pumping unit at surface and the units are not designed for high production rates, gas or significant solids. Consequently, beam pumps are used mainly in depleted reservoirs, where low rate, low GOR production is required.

**Electric Submersible Pumping**

Electric submersible pumps (ESPs) are centrifugal pump type units driven by an electric motor installed immediately below the pump: A schematic of an ESP system is shown in Figure 6.
Electric power is transmitted to the motor via an electric cable. The pump may be installed on the bottom of the tubing or run inside the tubing into a locking device in the tubing string. The pump itself consists of any number of stages (up to a hundred or so), each stage consisting of an impeller and diffuser with axial discharge. The number of stages depends on the ratio between discharge and intake pressure, and is the main design consideration.

The main advantages of the ESP are that it can produce low bottomhole pressures at almost any production rate, and without obtrusive surface units. However, it has the same disadvantages as the beam pump with regard to gas and solids, plus the added (major) disadvantage that the electric cable is highly prone to failure. Average pump run life is approximately 2.5 years across the industry.

**PCP Pumps**

Progressing cavity pump (PCP) systems are the favored artificial-lift method for wells with high solids, heavy API oil, and relatively moderate to high fluid volumes. They are also commonly used for heavy oil applications and thermal projects. See Figure 7.

PCP systems consist of a (steel rod) rotor and an (elastomer) stator that, when rotated by a surface drive system, causes reservoir fluids in the pump cavities to progress upward and move fluid from the intake to the discharge end of the pump.

The resulting continuous positive-displacement flow provides the highest volumetric efficiency of any conventional artificial-lift system. These systems are ideal for many environments such as heavy crude oil production, medium-to-light oil production, coalbed methane, and sand-laden, horizontal, slanted, and directional wellbores.
Plunger Lift

Plunger-lift systems are selected most commonly to efficiently and cost-effectively de-liquefy gas wells and also to produce oil wells with a high gas-to-liquid ratio.

A plunger-lift completion uses well reservoir pressure to periodically lift a plunger installed in a tubing string to the surface to lift fluids on top of the plunger. See Figure 8.
The plunger lift system consists of components such as plungers, upper and lower bumper springs, lubricators, downhole accessories, surface controls, and analysis software. The plunger cycles between the upper bumper spring at the surface lubricator and the lower bumper spring in the bottom section of the production tubing string. This creates a solid interface between the lift-gas below and the produced fluid above.

**Hydraulic Pumping**

Hydraulic pumps are reciprocating plunger-type pumps located at the bottom of the tubing string, as schematically represented in Figure 9.

![Hydraulic Pumping Diagram](image)

*Figure 9*

Power is transmitted by means of a hydraulic fluid to an engine attached to the pump, which in turn drives the pump. A hydraulic control valve directs the flow of power fluid alternately to each side of the engine, which is connected with a rod to the pump, and hence the produced fluid is pumped to surface. The power fluid returns to surface either mixed with the produced fluid or in a separate conduit.
The pump may either be installed at the bottom end of the tubing, or may be pumped down into a locking device located in the tubing string. The latter type is particularly attractive in that the pump can be retrieved without the use of a workover hoist to pull the tubing.

A variation on the hydraulic pump is called the jet pump. This type has no moving parts and operates by converting pressure into kinetic energy through a small nozzle (Bernoulli Principle).

The advantages of the hydraulic pump are that it can produce at high rates and at low bottom hole pressures, and that it is simple and cheap to operate. The main disadvantages are that it requires large volumes of a very clean power fluid, and that it cannot handle solids.

**Artificial Lift Selection**

The criteria for selection of a particular type of artificial lift mechanism are numerous and often complicated. Some of the main considerations are listed below:

- Reservoir parameters e.g., pressure, P.I., water cut, sand production, GOR
- Well parameters e.g., deviation, completion design
- Location e.g., land or offshore
- Cost
- Local experience
- Availability of resources
- Workover possibilities
- Standardization
- Reliability
## Summary

Advantages and disadvantages of these types of artificial lift mechanism are summarized below.

<table>
<thead>
<tr>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GAS LIFT</strong></td>
<td></td>
</tr>
<tr>
<td>No volume constraints</td>
<td>Requires high pressure gas / compression</td>
</tr>
<tr>
<td>No (minor volume) solids handling problem</td>
<td>Inefficient at low rates</td>
</tr>
<tr>
<td>Low operating cost</td>
<td>Limited drawdown capability</td>
</tr>
<tr>
<td>No well deviation constraints</td>
<td>Requires integral casing</td>
</tr>
<tr>
<td>No GOR limits</td>
<td>High pressure gas safety must be engineered</td>
</tr>
<tr>
<td><strong>BEAM PUMPING</strong></td>
<td></td>
</tr>
<tr>
<td>Simple system</td>
<td>Wellbore deviation limited</td>
</tr>
<tr>
<td>Reliable</td>
<td>Cannot handle high amounts of solids</td>
</tr>
<tr>
<td>Very low bottom hole pressures achievable</td>
<td>Cannot handle high GORs</td>
</tr>
<tr>
<td>Flexible and durable and proven</td>
<td>Depth limit (+ 2000 m.)</td>
</tr>
<tr>
<td>Low cost operations when properly set up</td>
<td>Not used offshore</td>
</tr>
<tr>
<td>Easy pump replacement</td>
<td>Obtrusive, Large</td>
</tr>
<tr>
<td></td>
<td>Cannot handle high rates</td>
</tr>
<tr>
<td><strong>ELECTRIC SUBMERSIBLE PUMPING</strong></td>
<td></td>
</tr>
<tr>
<td>Readily handles high rate fluid volumes</td>
<td>Requires reliable power source</td>
</tr>
<tr>
<td>Unobtrusive</td>
<td>Impractical in shallow, low rate wells</td>
</tr>
<tr>
<td>Simple to operate if properly designed / installed</td>
<td>Electric cable often source of problems; short out</td>
</tr>
<tr>
<td>No well deviation problem</td>
<td>Cannot handle high GORs</td>
</tr>
<tr>
<td></td>
<td>Cannot handle solids</td>
</tr>
<tr>
<td></td>
<td>Industry average run life +/- 2.5 years</td>
</tr>
<tr>
<td><strong>PCP PUMPS</strong></td>
<td></td>
</tr>
<tr>
<td>Positive displacement and non-pulsating</td>
<td>Limited by elastomers to low to medium ΔP</td>
</tr>
<tr>
<td>Accurate, repeatable flow</td>
<td>Limited by elastomers to crude API &lt; 34°</td>
</tr>
<tr>
<td>High temperatures to 350°F</td>
<td>(&gt; 34°causes excessive elastomer swelling)</td>
</tr>
<tr>
<td>High fluid viscosities to 1,000,000 cps</td>
<td>Excessive sand can shut down pump</td>
</tr>
<tr>
<td>Accommodates moderate sand &amp; particles</td>
<td></td>
</tr>
<tr>
<td><strong>PLUNGER LIFT</strong></td>
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</tr>
<tr>
<td>Uses reservoir gas to lift fluids / applicable for high GLR wells</td>
<td>Careful mechanical and well set up prior to plunger lift kick-off is essential</td>
</tr>
<tr>
<td>Ideal for unloading water off gas well formations</td>
<td>Sandy formations cause operating problems</td>
</tr>
<tr>
<td>No external energy required for lift</td>
<td>Requires close initial attention to design / set up</td>
</tr>
<tr>
<td>Appropriate for highly deviated wells</td>
<td></td>
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<tr>
<td>Good for remote wells</td>
<td></td>
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<tr>
<td>Very low cost</td>
<td></td>
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<tr>
<td><strong>HYDRAULIC PUMPING</strong></td>
<td></td>
</tr>
<tr>
<td>Depth limit not a major issue</td>
<td>Requires power fluid</td>
</tr>
<tr>
<td>No deviation well problem</td>
<td>Cannot handle solids</td>
</tr>
<tr>
<td>Used for short term well testing</td>
<td>Cannot handle high GORs</td>
</tr>
<tr>
<td>Flexible</td>
<td>Easy pump change out</td>
</tr>
<tr>
<td></td>
<td>By far, the most costly operating expense Art Lift</td>
</tr>
</tbody>
</table>