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WHITE PAPER

Gas Lift – From Design to Optimization

Archrock is the leading U.S. provider of natural gas contract compression services, with the country's largest fleet, well-established relationships with OEM manufacturers and distributors, and an unmatched aftermarket parts and service capability.

Gas lift is one of several options for artificial lift, with other options including beam/sucker rod pumping (currently the most popular method), hydraulic pumping, and electrical submersible pumping. Ideal for fields where a ready source of natural gas is available, gas lift is currently employed in 10% of producing wells in the U.S.

In actuality, the concept of using a gas to enhance the production of oil is more than 150 years old. As early as 1864, air was pumped to the bottom of wells in Pennsylvania to promote more robust production. In 1920, natural gas was first used to replace air in lifting operations. The technique was so popular that between 1929 and 1945 there were more than 2500 patents for various types of gas lift valves. In 1944, a patent was granted for the pressurized bellows valves used today.

How it Works

The process of gas lift begins by injecting high pressure gas through the casing tubing annulus. The presence of this gas serves to aerate the oil, reducing its density. With reduced density comes lowered flowing pressure requirements, which allows the existing formation pressure to effectively lift the fluid column to the surface. The amount of gas to be injected varies depending on well and formation characteristics.

This process is basically a closed-loop system by which the natural gas is recovered from the well and is then reused. Based on the goal of maintaining gas lift system pressure, it is important that the gas leaving the system (and being injected into the well) be balanced with the gas entering the system. Compression of the gas can play a key role in this process.

The rate of injection must be carefully calculated in order to optimize production, taking into consideration the well's inflow and outflow. This rate must also be balanced with the system's gas valves' passage capabilities. If the rate is too low, the well might be under-lifted. Correspondingly, if the rate is too high, the well may become unstable and begin to "multi-point" (lifting two or more valves simultaneously).

Advantages/Disadvantages of Gas Lift

To begin, gas lift is sufficiently versatile to accommodate changes in well conditions/producing rates, and can function effectively in deviated and long, horizontal wells. The process also employs relatively inexpensive downhole equipment, most of which offers long service life. Overall, the process is very cost effective, particularly when compared to other methods of artificial lift.

While not often encountered, there are some disadvantages associated with gas lift. High well backpressure can restrict production in some gas lift operations, becoming more of an issue in applications where conditions include increasing depths and declining bottom-hole pressures (BHP). In addition, problems associated with lifting low-gravity crude (less than 150 API) can be exacerbated by the inherent cooling effect of the gas, itself.

From an operational perspective, there must exist a dependable supply of gas throughout the life of the project. Finally, the capital expense of compression equipment can be an issue, as can the need for trained personnel to manage and maintain the operation.

Considerations in Developing a Gas Lift Operation

In establishing and implementing an effective gas lift operation there are several factors to be considered. The overall production potential of the well or the field must be evaluated, along with the available gas pressure and volume. The optimum production rate and gas allocation must also be calculated. From those considerations, the operator can determine compression requirements.

When a decision is made to employ gas compression, the operator must then begin the process of selecting and configuring gas compression equipment. Finally, monitoring and control issues must be strategically addressed, as do the system's maintenance requirements.

Types of Gas Lift

Gas lift operations can be either intermittent or continuous. One option, continuous gas lift, is often used with high Productivity Index (PI) wells, exhibiting high Bottom Hole Pressure (BHP). With this type of well, the process begins by using compressed gas to push the liquid back into the formation, and then maintaining the flow of the liquid by continuous injection of natural gas.

By contrast, intermittent injection is generally applied to low volume wells that exhibit high PI and low BHP, or low PI and high BHP. This intermittent process is controlled via time-cycle and choke control methods, or a combination of both.

Gas lift technology can be employed in horizontal wells in addition to classic vertical wells. In horizontal applications, gas is injected into the deviated (or horizontal) portion of the well in order to sweep the liquid production from the horizontal segment to the vertical part of the well. When engaging in gas lift operations for horizontal or deviated wells, the gas lift valves (discussed later) must be installed using coiled tubing of tractors, since wireline can only be effective when used to approximately 650 from vertical.

Gas lift can also be implemented on a dual injection, as well as single injection, basis. Dual gas lift operation is inherently the same as single injection, except for employing two tubing/completion strings, through which gas is simultaneously injected.

The goal of dual lift operations begins with the requirement of injecting gas as deep as the system allows in order to aerate as much of the production fluid as possible. In addition, the dual configuration enables the gas to be injected at a very stable rate and pressure, avoiding costly inefficiencies. Finally, this process provides the operator with the capability of injecting both sides of a well, ensuring that one side does not receive all of the gas.

Distribution or Individual Wellhead Systems

The natural gas necessary to provide sufficient injection pressure can be provided by a single compressor located at the individual wellhead. Alternatively, one can employ a distribution piping system, supported by a large compressor or multiple compressors that service a number of wells within the same location. With some distributed piping systems, each individual well is directly serviced by dedicated piping. However, the most popular method has the gas brought to an injection manifold and distributed from that manifold to individual wells.

While more complex and expensive, there are some key benefits associated with using a manifold system. The flow of natural gas can be measured and controlled at one location, and upsets in one well are much less likely to impact the adjacent wells.

Downhole Gas Lift Design

There are several elements that comprise a gas lift system – well completion tubulars, gas lift valves, gas lift mandrels, and various downhole measurement and control instrumentation.

The well completion tubular components include surface casing, production casing, a liner (if required), tubing, and a packer. The production casing must be sufficiently large to accommodate 2-7/8" tubing, and even larger diameter tubing in some wells. While the liner may not always be necessary, when used it should be set below the depth of the deepest mandrel. While 2-7/8" tubing is the size normally employed in gas lift systems, some larger and smaller tubing strings are used. Packers are used in most gas lift systems to prevent excess pressure on the formation.

Gas lift valves, designed to be set at differing depths, provide the means to adjust the rate of gas injection into the liquid column. Normally pre-set to pressure ratings based on system design, these valves' open and close actions allow gas to be injected into the fluid held in the tubing. At the same time, gas lift valves also let the fluid in the casing escape through them and into the production string. Installed on or in the mandrel, which is placed on the production tubing, these valves are operated by the pressure inside the tubing and casing. Gas lift valves are available as Injection Pressure-Operated (IPO) valves or Production Pressure-Operated (PPO) valves. Today, many operators prefer IPO valves, based on their inherent reliability and superior performance.

There are two types of gas lift mandrels, conventional design and side pocket design. Their placement depth is determined by the gas lift system design, including gas lift injection pressure, the overall depth of the well, and a number of other related factors.

When conventional mandrels are used, the gas lift valve is seated into a lug on the outside of the mandrel. The mandrels are tubing-retrievable, so the tubing must be extracted in order to access the mandrel and gas lift valve. By contrast, with side pocket mandrel designs, the gas lift valve is installed in a pocket inside the mandrel. For this configuration, the mandrel and gas lift valve are wireline retrievable, and can be accessed without having to pull the tubing.

Some operators employ a range of downhole measurement processes, using electronic or hydraulic control from the surface. Using a range of control devices, it is possible to measure the rate of injection through a valve, and control that rate simply by adjusting the valve opening from the surface. These measurement systems should be installed prior to beginning gas lift operations. With the necessary systems in place, the operator is able to monitor the unloading process and the start of the gas lift process. From there, these systems will allow for monitoring and control of the ongoing gas lift process, while also serving to detect and diagnose specific problems.

There are several options for controlling the gas lift injection rate. While operators have a choice of using an automated control valve or a fixed choke, many find the automated control valve to be superior in terms of maintaining a consistent rate of flow.

Surface Gas Lift Elements

A wide range of surface equipment, including compressors, separators, and dehydration systems, is critical to the gas lift process. Compressors can be used for an individual well (wellhead compressor) or a group of wells (compressor plant).

Wellhead compressors, with discharge pressures up to 1300 psi, can effectively handle the compression needs of a well, whether operating on a continuous or intermittent basis. Compression plants, employing single or multiple compressors up to 2000 psi and higher, are designed to serve a number of wells.

Another piece of equipment found on the surface is the bulk separator, which can manage the needs of several wells simultaneously. These separators, available in horizontal or vertical packages, separate liquid production, gas, and water as well liquid production and gas. Test separators are designed to test individual wells, one at a time, as the wells' production passes through them. Wells are often connected to a production manifold, so they can be switched to bulk or test separators, as required. Some of these test separators can measure liquids and gas. Others are capable of measuring oil, gas, and water.

Dehydration equipment is also often included as part of the surface equipment system, since gas used in gas lift operations needs to be dehydrated to 7 lbs./million. Where the addition of dehydration equipment is not feasible due to cost or space, glycol injection or line heaters may be employed.

There are a number of measurement, reporting, and alarming devices which can be mounted on or near the wellhead. Key measurements can include flowing bottom-hole pressure and temperature, static bottom-hole pressure, and flowing pressure in the tubing. A standardized system offering communications, user interface, event database, plotting, alarming, and reporting capabilities is critical to an effective gas lift system. Today, many operators prefer automated systems, which both ensure accurate reporting and alarming, and while also reducing manpower requirements.

In-House Vs. Outsource Gas Lift Compression Services

The decision to purchase and manage gas lift compression operations in-house, or contract for services, has become a very significant issue with many operating companies. Decreased capital availability, combined with low (and volatile) commodity pricing, makes this purchase equipment vs. buying compression services an even more complex decision. Key considerations in this decision process can include the lowest overall cost for compression, equipment availability and sustainable high-run times, and long-term operating flexibility.

Owning and operating one's own gas lift compression equipment can represent a very large investment, including funding for large-scale capital equipment purchases along with spare parts and swing engine inventory. There are also significant costs associated with establishing and operating maintenance and repair facilities. And finally, having the right personnel on staff, capable of running gas lift compression operations in an efficient and effective manner, requires another major investment.

Contract gas lift compression services are seen by many as a viable alternative to in-house operations. For a set cost against production, the gas lift compression requirements of a well or a field can be managed by companies and personnel who are experts in the technology. In addition, buying the service means operator costs are limited to real production-related activities, as opposed to the ancillary costs of idle equipment and crews.

In-house and outsourced management of gas lift compression operations will both continue to be viable options. However, given the nature of the commodity markets today, one can anticipate a growing acceptance and utilization of outsourced compression services.

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To Recap

Gas lift operations can be a critical factor in the production of oil. To realize the maximum benefit from a gas lift program, the effort must be carefully planned and implemented. The type of gas lift system to be used must be developed based on the nature of individual wells or that of a field, with downhole systems carefully designed based on well conditions and production goals. Another consideration is whether to execute gas lift compression operations in-house or employ one of the several companies offering turnkey gas lift compressions services. Based on the number of factors that can be taken into consideration, and the far-reaching nature of the decision, this in-house vs. outsourced determination is critical to the profitability of a well or an entire production field.

Archrock is the U.S. leader in gas compression services, with facilities located strategically in key domestic producing areas. In addition to providing gas compression services for gas lift operations, Archrock's range of services also includes contract gas compression for production, gathering, and distribution activities. To further support the gas compression market, Archrock offers a full range of revamp, repair, rebuild, maintenance and parts service.

For more information

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