GAS LIFTING LIQUID-RICH SHALE PLAYS

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ABSTRACT

Advanced exploration into, and production from, liquid-rich shale plays demands efficient and economical strategies to extract fluid accumulation throughout the lifetime of individual wells. The need for artificial lift will become inevitable at some point to sustain and/or maximize production. Gas lift is a form of artificial lift that most closely resembles the natural flow of a well, and as such, is an effective intermediate step in a well's life.

This presentation will discuss the principles of gas lift, advantages and challenges to gas lift and other potential solutions, as well as explore how actual wells have benefitted from gas lift installation compared to other deliquification methods.

INTRODUCTION

Over recent years, the oil and gas industry has begun to shift exploration and production focus from areas such as the booming Barnett, Haynesville, and other popular gas-driven shale plays to liquid-rich shale plays, like the Bakken, Eagleford, Niobrara, and Wolfcamp. The majority of these new liquid-rich wells will initially benefit from "natural lift" and flow on their own for a period of time at high rates. Then, like all wells, they will need some lifting help from an artificial source to enhance the reservoir's ability to flow. By supplementing the missing formation gas required at depth via injected gas from surface to lift accumulated fluids, gas lift is an effective economical solution to extract resources from liquid-rich shale plays. Understanding continued production declines allows for the planning of different lift forms in the first few years or stages of production. A gas lift system should be considered over the life of the well.

The demand for artificial lift is high and will continue to stay elevated as unconventional liquid-rich wells are drilled and steep decline rates continue. This demand necessitates a better understanding of how artificial lift systems operate and the boundaries in which they can be used in.

PRINCIPLES OF GAS LIFT

Liquids begin to accumulate in the well and at some point the reservoir will no longer have adequate energy to lift these fluids. A designed number of gas lift mandrels, each equipped with a pre-set nitrogen charged valve and check valve as shown in Figure1 will be installed at pre-determined depths. The goal of the system is to have a single point of gas injection as deep as possible. Each valve is set to open and close based off of a designed set pressure *(Figure 2)*. Assuming there is fluid to surface in both the tubing and casing, all valves are open due to hydrostatic pressure in the beginning *(Figure 3)*. Injecting compressed high-pressure gas into the casing from surface is started; fluid is passed through the top valve, or valve #1, until the casing at that valve is uncovered *(Figure 4)*. As gas passes through the top open valve in the casing, it creates a decrease in the flowing tubing pressure above the top valve as the system continues to work down to valve #2. The casing pressure will start to decrease as the back side continues to unload. Because valve #1 is set to close at a certain pressure, it will close as casing pressure drops below the designed charge of the valve. As shown in Figure 5, the system is now working off of valve #2; valve #1 has closed and the system begins to transfer down to valve #3. The process continues until injecting as deep as possible through one singe valve *(Figures 3-8 represent the full unloading sequence)*.

SYSTEM REQUIREMENTS

In addition to the mandrel, valve, and check downhole, there a few surface requirements as well. One of the most essential requirements to the gas lift system is available high pressure gas provided by an electric or gas driven three stage compressor. A gas flow meter installed downstream of the compressor will allow monitoring and measurement of injection gas. The lower the wellhead back pressure or separator pressure, the more differential that is created and allows for a more efficient gas lift operation. Adequate injection gas supply is another requirement, whether buying back gas, re-circulating gas, or pulling gas from other wells. In addition to the aforementioned surface requirements, a two-pin recorder or some sort of SCADA system to accurately monitor tubing and casing pressure, injection rates, and production is necessary.

ADVANTAGES

Gas lift is a very simple operation compared to many other forms of artificial lift. There are no restrictions in the tubing so wire-line operations and/ or gas lift assisted plunger lift are options. Each gas lift system is designed to handle a wide range of rates and changing well conditions. Gas lift works well in deviated and sand producing wells. Reservoir gas helps the system, as gas can interfere with other forms of artificial lift. When comparing other forms of artificial lift, gas lift has low initial and operating costs.

DISADVANTAGES

Wells with low bottom hole pressure will usually produce higher rates on other types of artificial lift. As previously mentioned in the requirement section, high pressure gas supply must be available. Some wells may not have enough gas to re-circulate, may not be near a high pressure line that the well can pull from, or not have surrounding wells with an available surplus of gas. Because the injection gas has a cooling effect on oil, low API oil wells usually do not make good gas lift candidates.

CASE STUDIES

An artificial lift system is intended to lift the liquids to surface and minimize the back pressure exerted from the column of liquid in the wellbore. This reduction in back pressure returns flow back to the reservoir to increase or maintain production. Understanding the production rates of the liquid-rich reservoirs is complicated by the steep decline rates that are typical of this type of reservoir. This steep decline must be considered when selecting the artificial lift because the initial production rates can be high but decline rapidly. The gas lift systems discussed in the following case studies review the flexibility of the system to handle the fluctuating production rates.

Natural Flow vs. Gas Lift (Table 1)

As newly completed Bakken Shale horizontal oil well produced naturally for 53 days before loading. The well started to show signs of loading around day 40. At that point, it was decided to complete a continuous-flow gas lift design and system to prepare for the well to load. At day 53, the well loaded and the gas lift system was installed. Between waiting on work-over rig availability and the installation process, the well was down for 8 days. After the installation process the well was “kicked-off” with the gas lift system and for the initial 10 days the well experienced flushed production from being shut in previously. From that point, the well returned to its decline curve and continued to produce with the assistance of gas lift.

ESP vs. Gas Lift (Table 2)

An Avalon Shale/Bone Springs well was initially produced via an electric submersible pump (ESP). Due to down-hole issues with the ESP, the system was pulled and a gas lift system was selected to replace the failed ESP. The difference in artificial lift systems draw-downs was considered and the operator determined that the loss in draw-down was worth the extended life on production. As expected, the well was produced with gas lift but at lower initial production rates compared to the ESP. One unexpected item to note is the increase in oil production when the artificial lift method was changed. This is a result of the oil bearing zone having a higher reservoir pressure compared to the water zone. The difference in flowing bottom-hole pressure (FBHP) caused the change in production.

Gas Lift vs. Sucker Rod Pump (Table 3)

A Wolfcamp horizontal well was initially produced via a continuous gas lift system. The system performed as expected and produced the well for approximately 330 days. The gas lift system maintained the well to its determined decline curve. As the reservoir pressure and fluid production decreased, the continuous gas lift system became less efficient. Once it was determined that the gas lift system had resulted in the lowest possible FBHP, the system was pulled and a pumping unit was installed. The pumping unit was able to lift the lower fluid rates more efficiently thus increasing the production from the reservoir.

Table 1
Natural Flow vs. Gas Lift

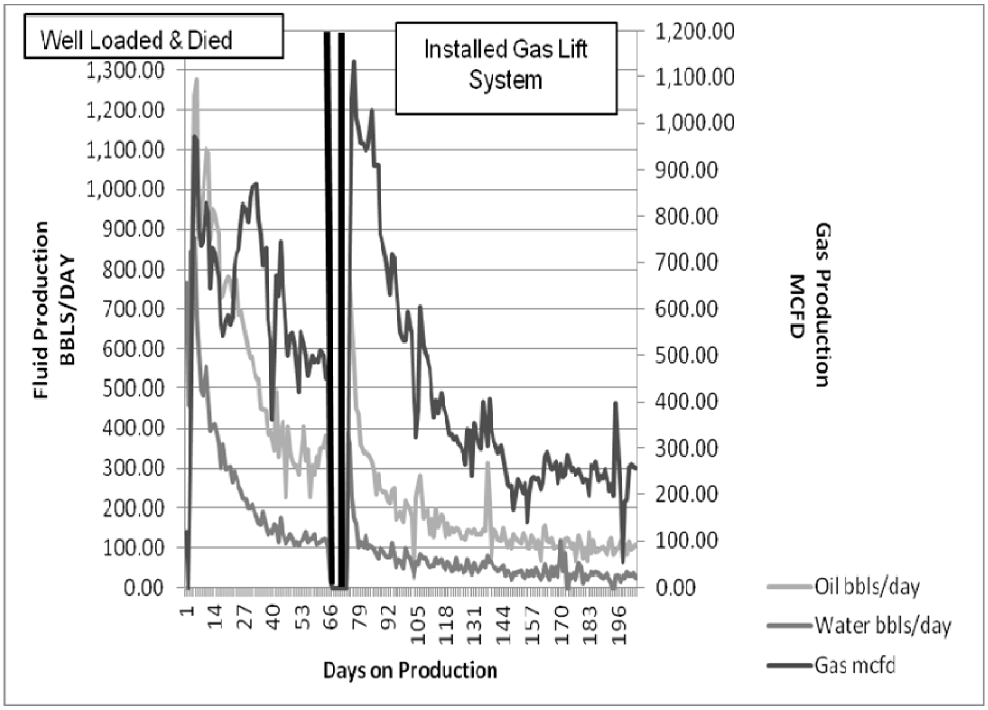


Table 2
ESP vs. Gas Lift

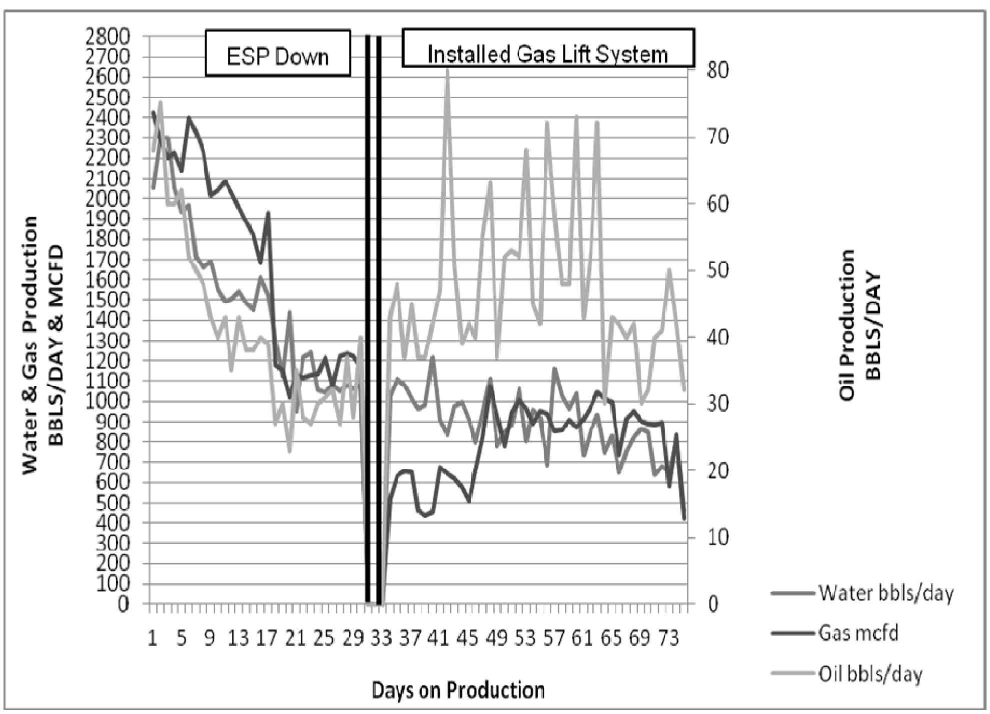
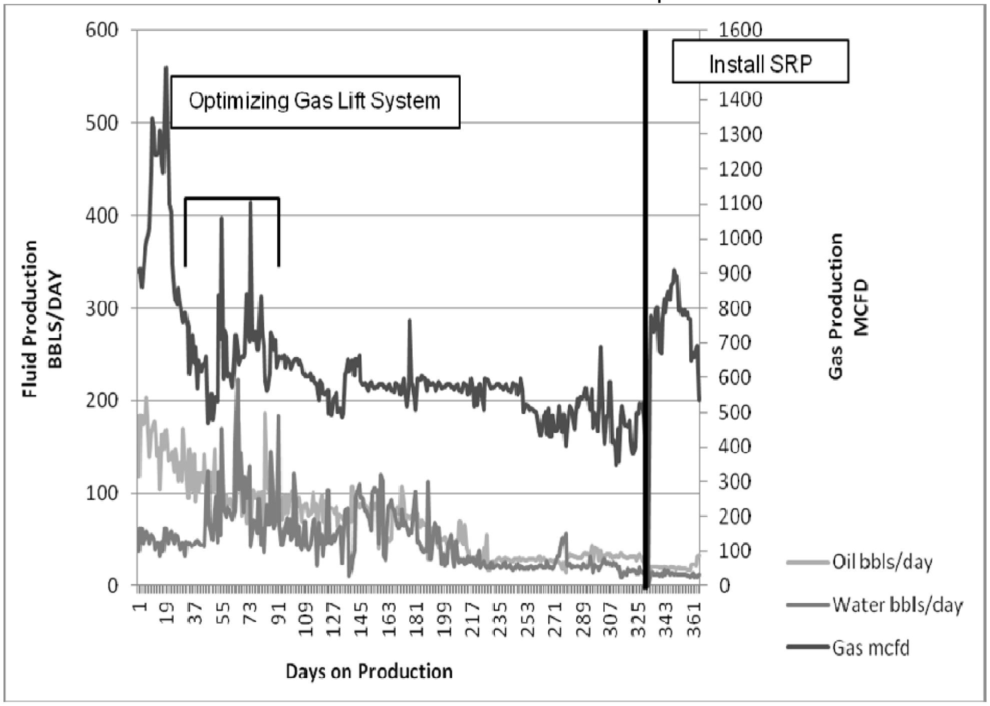


Table 3
Gas Lift Production vs. Sucker Rod Pump Production



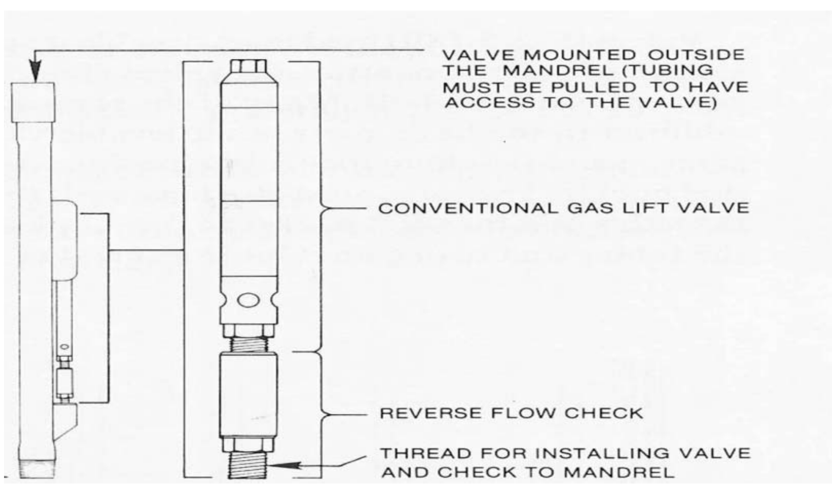


Figure 1

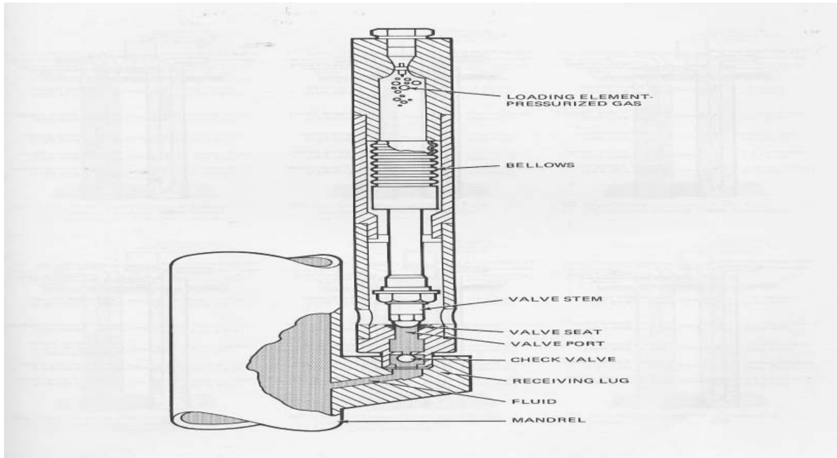


Figure 2

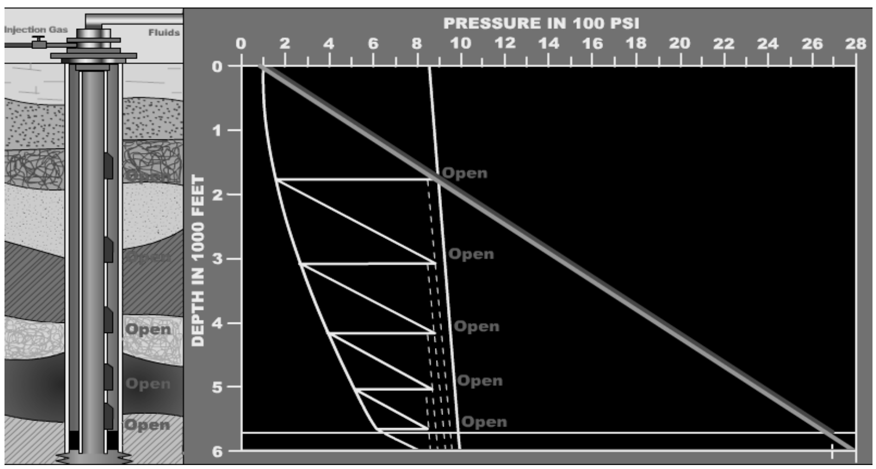


Figure 3

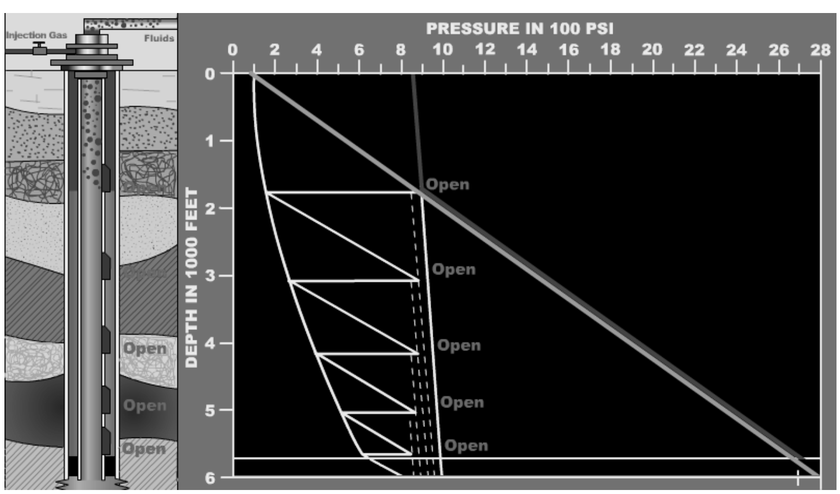


Figure 4

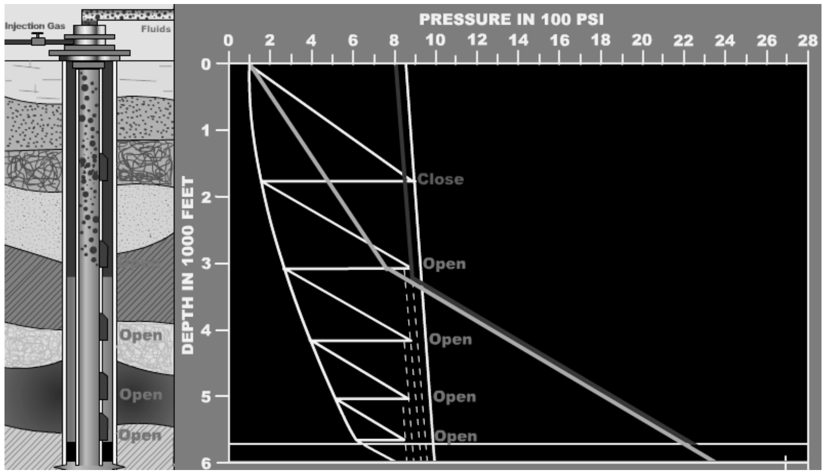


Figure 5

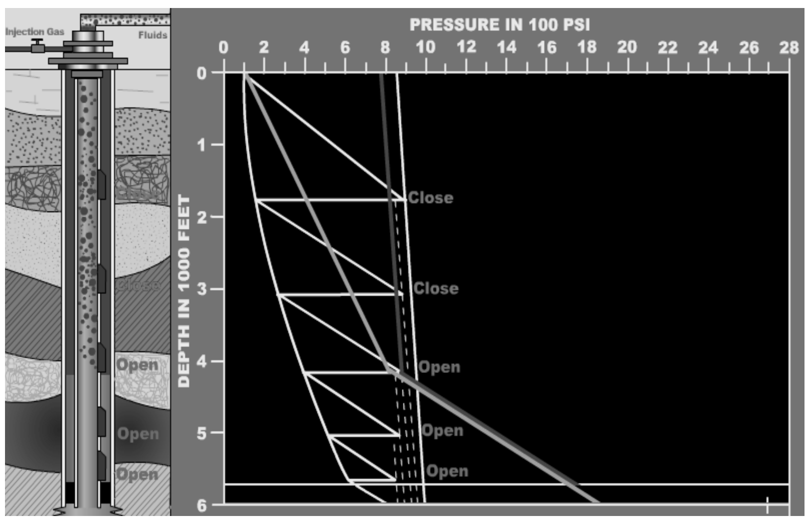


Figure 6

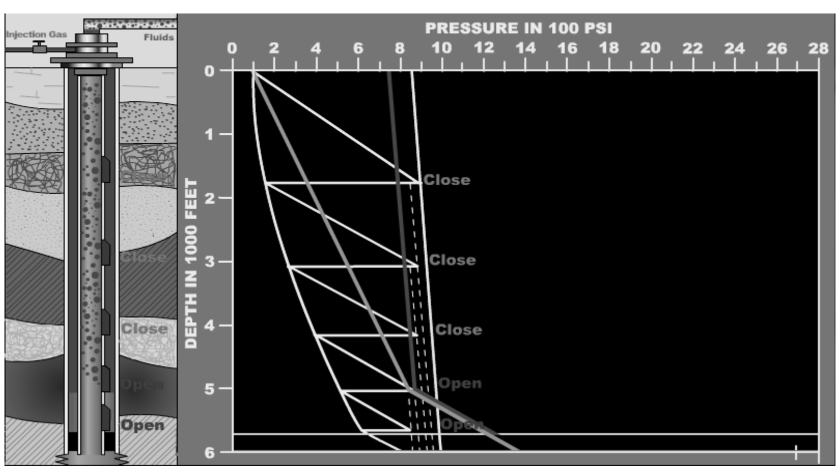


Figure 7

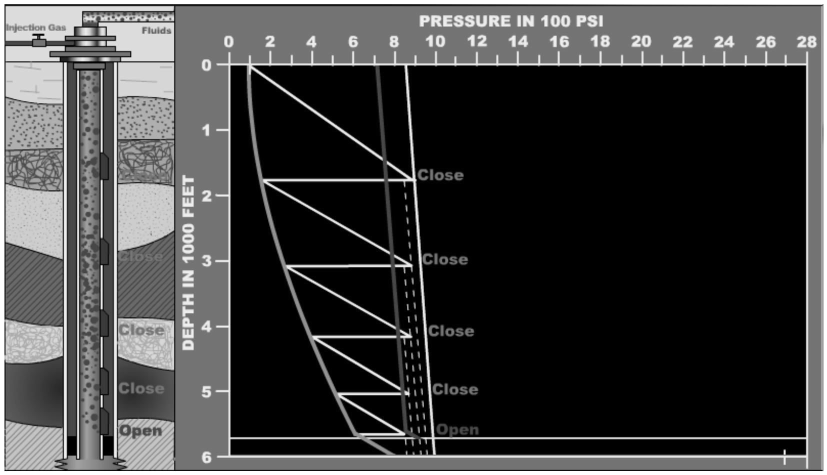

Injection Gas
Fluids
PRESSURE IN 100 PSI
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28
DEPTH IN 1000 FEET
0
1
2
3
4
5
6
Close
Close
Close
Close
Open
Close
Close
Open

Figure 8