# PLUNGER LIFTING WELLS WITH SINGLE WELLHEAD COMPRESSION

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## ABSTRACT

As gas wells are produced and reservoir pressures decline, it is often necessary to install wellhead compression to maintain production. As the well continues to decline, gas rate and velocity in the tubing will decrease to the point where liquids cannot be lifted out of the wellbore. Even on compression, liquid loading will become a problem and production impairments will result. One remedy to the problem of liquid loading is to install a plunger lift system coupled with compression. With new "smart" controllers, the plunger/compressor combination has been successfully installed on a number of wells. This paper describes the installation of this type of system, and provides case histories of active installations in the San Juan Basin.

## INTRODUCTION

To maximize gas well production, back pressure on the formation must be kept to a minimum. There are a number of problems that can cause back pressure in a gas well and impair production. These include high friction pressure losses in the wellbore, tubulars, or surface equipment; high sales line pressures; and liquid loading. High friction pressures can be resolved through mechanical modifications to tubulars or surface equipment. High line pressures can be addressed through some form of compression. Liquid loading can be resolved by soaping, plunger lifting, smaller tubing, or beampumping. This paper focuses on remedies for problems associated with a combination of high line pressures and liquid loading.

## THEORY

High line pressure can severely impair gas well production. As a well experiences a decline from original reservoir pressure, bottom hole shut-in pressure decreases. When line pressure becomes greater than about 20% of bottom-hole shut-in pressure, production becomes impaired. This can be seen on an inflow performance relationship curve **(Figure 1)**. As reservoir pressures continue to fall, the well has increasing difficulty in flowing. Eventually, the well will not be able to produce against line pressure. Before this point, it is usually economical to install compression. This results in lower surface flowing pressures, and increased production.

Coupled with falling production rates is liquid loading. Most gas wells will experience liquid loading at some point in their life. Liquid loading occurs when gas velocity in the tubing falls below a minimum velocity required to lift liquids out of the wellbore (approximately 8 to 20 ft/s) **(1)**. As long as a gas well will produce at a rate high enough to keep gas velocity above this minimum, liquids will be removed from the wellbore. If gas velocity falls below this minimum, liquid droplets will accumulate in the wellbore, build a liquid column, and increase back pressure on the formation.

A number of factors control gas velocity in the tubing. These include gas rate, tubing size, and surface flowing pressure. Turner et al, developed relationships between these factors to predict loading rates in gas wells **(1)**. Examples of predictions based on the Turner et al, equations can be seen in **Figure 2**. Back pressure resulting from liquid loading will severely inhibit production.

A number of solutions are available to combat liquid loading. Gas rates can be increased through gas lift, pay additions, or commingling zones, thus increasing gas velocity in the tubing. Tubing sizes can be reduced to increase velocity in a given volume of gas (velocity tubing strings). Surface flowing pressures can be decreased through compression.

Another solution to liquid loading involves improving the liquid carrying capacity of a gas. Soaping and plunger lifting are two methods that lower the required gas velocity to lift liquids. In soaping, liquids are foamed, forming a lightweight column easily moved out of the wellbore by low tubing velocities. In plunger lifting, the plunger acts as a solid interface between liquids and gas, preventing liquids from falling back (similar to a pig in a horizontal pipeline).

When compression is first installed, a flush production rate occurs, and surface flowing pressure is greatly reduced. If the well was experiencing loading problems, the compressor can eliminate these problems by reducing surface flowing pressure and increasing gas rate. The well will eventually stabilize, and then decline in rate and reservoir pressure. As the decline continues, gas rates and therefore velocities can fall below those required to unload liquids. This leaves the operator with the problem of having to solve liquid loading problems. This paper focuses on solving the problem of unloading a well while on compression by coupling a plunger lift system with the compressor.

Before a description of the compressor/plunger system, a few terms should be defined about plunger lift operations. A plunger cycle consists of three periods: 1) a shut-in period-- where the well builds pressure, 2) an unloading period-- when the well is initially opened to flow and the plunger brings fluids to the surface, and 3) an afterflow period-- when the plunger is at the surface, well is flowing gas, and fluids are entering the wellbore. At the end of the afterflow period, the well is shut-in, the plunger drops to the bottom of the well, and the cycle begins again. For a more detailed discussion on the operation of plunger systems, please refer to the references at the end of this paper **(2,3,4,5)**.

## APPLICATION

A typical electric compressor/plunger installation is fairly simple and is shown in **Figure 3**. The flow process is similar to that of a standard compressor installation. Gas flows from the wellhead, through surface separation facilities, through the compressor, and finally to sales. When adding a plunger system, a plunger and plunger stop are installed downhole, a motor valve and an electronic control "box" (a programmable logic controller) are added between the separator and compressor, and an electrical plunger sensor is installed on the wellhead. In addition, an electrical on/off switch is installed on the compressor. This on/off switch is controlled by the plunger controller.

At the beginning of the production cycle, the well is shut-in and the compressor is off. After a set period of shut-in time (typically from 1/4 to 1 hour) the control box opens the motor valve and sends an electrical signal turning the compressor on. The unloading period begins and the plunger brings gas and fluids to the surface. After about 6-15 minutes (a time period dependent on well depth), the plunger arrives at the surface and afterflow begins. During afterflow, the well produces as a normal well on compression. After a set period of afterflow, generally from 1/4 to 2 hours (a time period dependent on loading conditions), the control box shuts the well in and turns the compressor off.

The purpose of the wellhead sensor is to detect plunger arrival at the surface. The control box uses this input to calculate the time it takes the plunger to travel from the bottom of the well to the surface (travel time). Travel time, as it relates to plunger velocity, is a key tool in gauging the efficiency of the plunger system **(5)**. A logic program in the control box records travel times and makes adjustments to shut-in and afterflow times, and thus optimizes production from the well.

Detecting arrival times is probably the biggest advantage of microprocessor controlled plunger systems over their older counterparts (5,6). The older systems utilized pre-set cycle times based on average line pressures. This led to upsets in the system any time that line pressure changed, making operation difficult and manpower intensive. Newer plunger systems can make automatic adjustments for line pressure changes (which the controller senses as changes in plunger arrival time). This keeps the plunger optimized and minimizes operator adjustments.

An installation for a gas powered compressor (**Figure 4**) has a few minor differences from an electric installation. Since, it is not practical to turn a gas powered compressor on and off during a plunger cycle, a bypass is utilized. Tandem motor valves make this system possible. One motor valve (Valve 1 in **Figure 4**) operates the full flow bypass. The other motor valve (Valve 2) allows flow to sales. During the shut-in period, Valve 1 is open and Valve 2 is closed. Gas is cycled through the compressor, with minor amounts of gas being taken from the production tubing to makeup for fuel volumes. Minimal work is done by the compressor during shut-in, and the only gas volume losses occur in fuel gas use (minimal, since horsepower requirements are minimal). At the beginning of the unloading period, the control box opens Valve 2 and closes Valve 1. The compressor begins moving gas down the sales line, and the plunger travels to the surface. During afterflow, gas is produced from the well and compressed as in a standard compressor installation. At the end of the afterflow period, Valve 1 is opened and Valve 2 is closed, the plunger falls back to the bottom of the well, and the cycle begins again.

A modification that can be added to enhance the liquid lifting ability of a plunger/compressor system is shown in **Figure 5**. In this figure, a third motor valve (Valve 3) is installed to direct compressed gas back into the casing. Initially, during the plunger's unloading cycle, Valve 3 will be closed. If the plunger does not arrive at the surface after a set period of time, Valve 3 will open, and compressed gas will be injected into the casing. This additional gas increases velocity in the tubing, and helps to push the plunger and liquids to the surface. When the plunger arrives at the surface, Valve 3 closes, and all the compressed gas is moved down the sales line. This recirculation option is not discussed in the case histories of this paper, but has been used successfully in other parts of North America (8).

## CASE HISTORIES

In the San Juan Basin, a typical well is a Mesaverde or Dakota gas well producing from between 3500' and 7000', at 50 to 500 mscfd and 1 to 20 barrels of liquid per day. Shut-in pressures range from 300 psi to 600 psi, and average line pressures are 150 to 350 psi. Eleven wells have had a combination compressor/plunger lift system installed. Of these wells, 3 are Dakota producers, 7 are Mesaverde, and 1 is a coal gas well. Six of the compressors are gas operated, and five are electric.

Only three wells will be discussed in this paper. In each of these wells, compression was installed to increase production due to high line pressures. Initial rates on compression were high enough to prevent liquid loading. However, after periods ranging from one to nine months, loading became a problem. On each of these wells, a plunger lift system was installed.

### State Com AD 26

The State Com AD 26 produces from Dakota perforations at 6356 to 6394'. As can been seen from the decline curve (**Figure 6**), production in this well was severely impaired in 1992. In March of 1993, a gas compressor was installed. The compressor increased production to 250 mscfd. After initial flush production, the rate dropped below 225 mscfd-- the minimum rate required to keep 2-3/8" unloaded at 60 psi flowing pressure (**Figure 2**). After four months of impaired production, a plunger lift system was installed, and run in combination with the gas compressor. The plunger assisted in the unloading of liquids, and returned production to 250+ mscfd.

State Com K 7A

The State Com K 7A produces from Mesaverde perforations from 4992 to 5525'. The well produced through 2-3/8" tubing set at 5453'. A gas compressor was installed on this well in November, 1993, due to high line pressures. Rates increased from below 100 mscfd to 250-300 mscfd **(Figure 7)**. After approximately 9 months, the well began to experience loading problems. Production had dropped below 250 mscfd, the rate required to keep the well unloaded in 2-3/8" tubing. To keep the well unloaded, a plunger lift system was installed. Production increased from 120 mscfd to 200 mscfd.

Walker 1

The Walker 1 **(Figure 8)** is a Dakota well that produces from perforations from 6384 to 6556'. This well produced through 1.66" OD tubing. An electric compressor was placed on this well in July, 1993, due to high line pressures. Rates increased from approximately 15 mscfd to between 50 and 70 mscfd. After 5 months, the well was diagnosed with liquid loading, and a plunger system was installed. The plunger unloaded fluids for 1 week, but failed to increase production afterwards. A tubing leak was discovered shortly after plunger installation, and in January, 1995, the 1.66" tubing was replaced with 2-3/8" tubing. A 2-3/8" plunger system was also added to the well. The 2-3/8" tubing not only resolved the tubing leak, but made plunger operation on this well much easier. This is due to the fact that with larger tubing, less wellbore pressure is required to lift a given volume of fluid. This gives more flexibility in the timing of plunger cycle periods (shut-in, unloading, and afterflow), and allows greater volumes of fluids to be unloaded at lower pressures. A more detailed explanation of the effects of larger tubing on plunger operations is given in the references **(5,7)**. The result of the tubing change/plunger installation was an increase in production from 50 mscfd to 120 mscfd.

## DESIGN CONSIDERATIONS

A few factors should be taken into account when designing compressor/plunger systems:

1. Facilities should be designed to handle high gas and fluid rates at the beginning of the plunger unloading cycle. This includes separators, dehydrators, and tanks.

2. Compressor capacity versus horsepower requirements should be calculated at expected rates and pressures. Compressors that require suction pressure controllers will hinder plunger operations. Suction pressure regulators place backpressure on the well when the plunger is initially unloading fluids. This decreases unloading efficiencies and will make the well more difficult to operate.

3. Using a suction pressure controller on a gas powered compressor can produce increased friction across the controller and engine loads when the compressor is bypassing gas (idling). This will decrease efficiency of operation and could lead to high temperature gas problems in the compressor.

## CONCLUSIONS

Even with wellhead compression, wells will suffer from liquid loading problems if the gas velocity in the tubing drops below the minimum required to unload liquids..

Coupling a plunger lift system with a gas or electric compressor is a viable and successful method of keeping a gas well unloaded and producing at maximum efficiency.

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## ACKNOWLEDGEMENTS


Special thanks to Conoco, Inc. for allowing the publication of this paper, especially to John Skopak, Dan McCoy, Mike Onan, and Bill Elmer. Also, thanks to Randy Thille of Ferguson-Beauregard, Farmington, for his assistance in design and implementation.

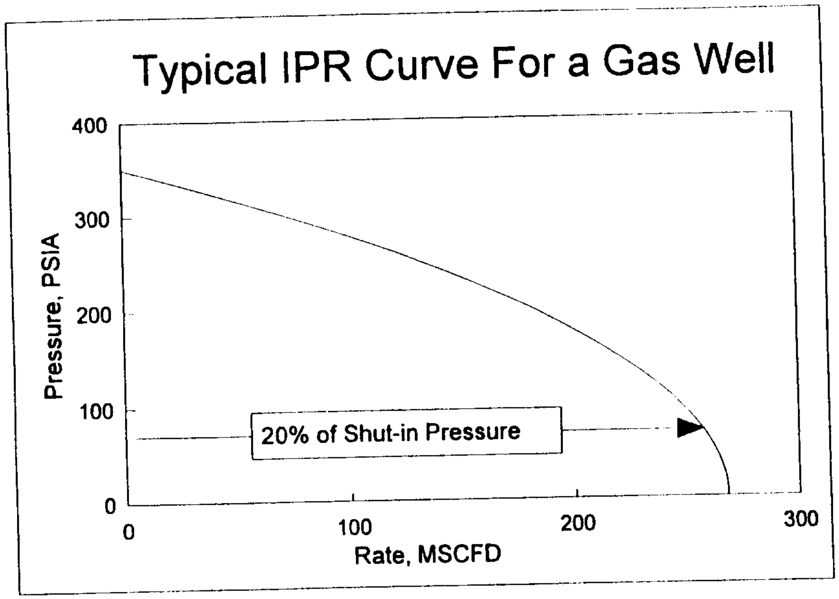


Figure 1

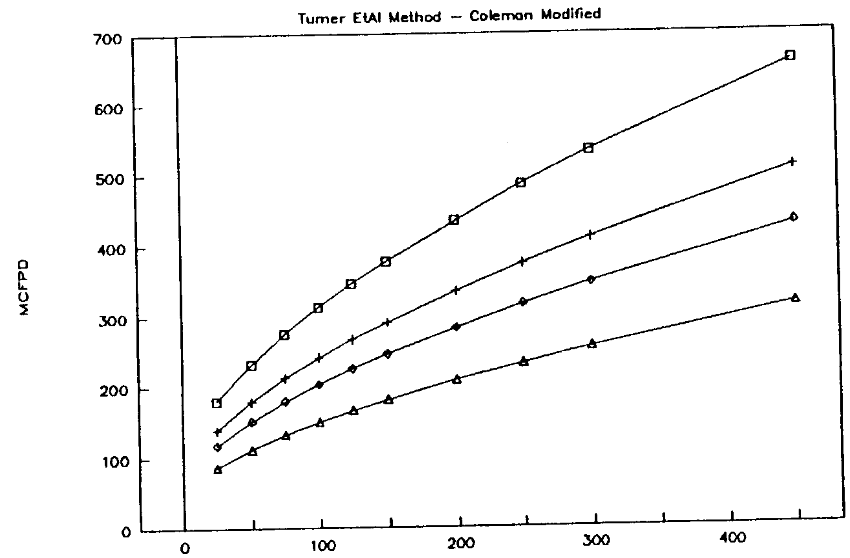


Figure 2 - Unloading flowrates vs. tubing size

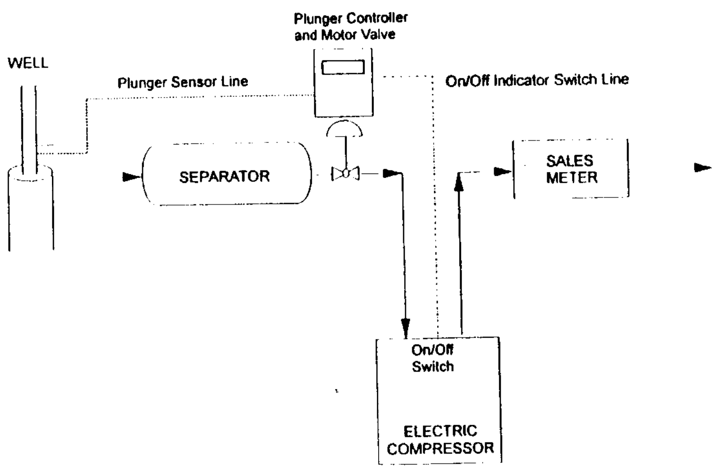


Figure 3 - Electric Compressor / Plunger Lift

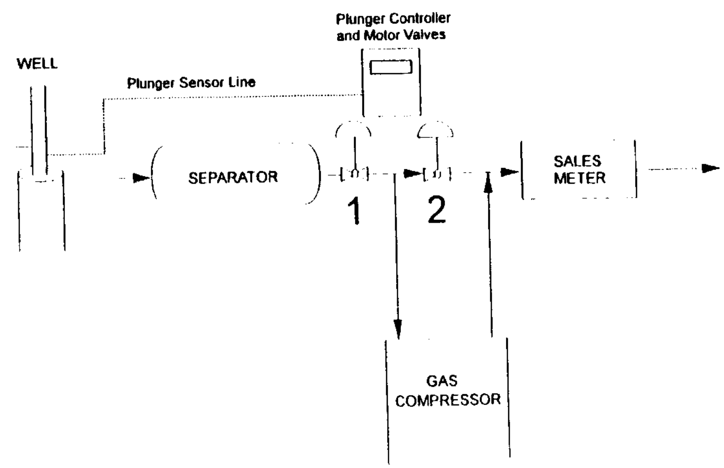


Figure 4 - Gas Compressor / Plunger Lift

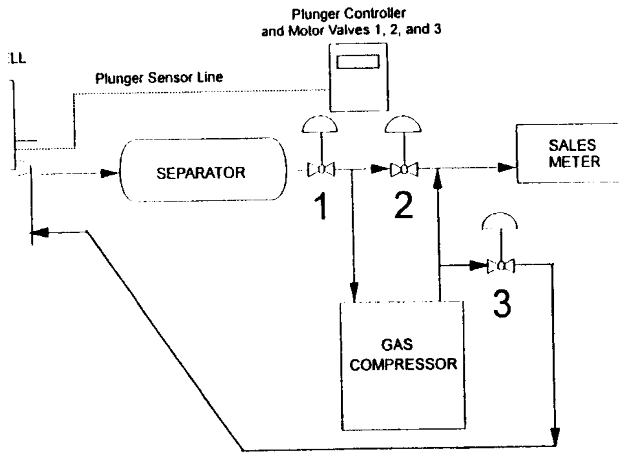


Figure 5 - Gas Compressor/Plunger Lift Recirculation Option

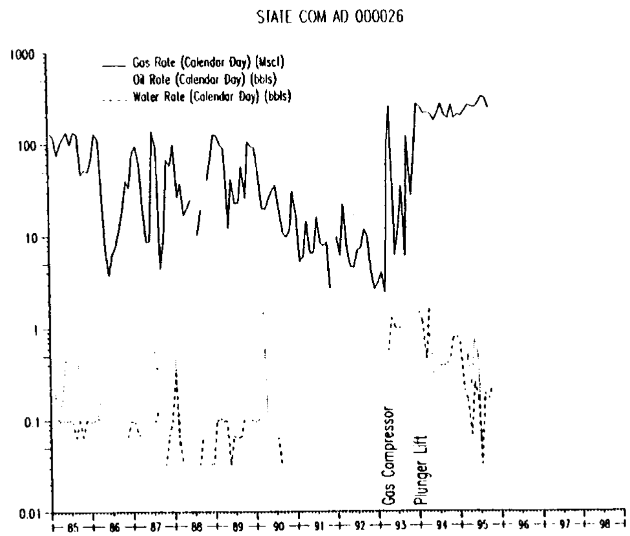


Figure 6 - State Com Ad 000026

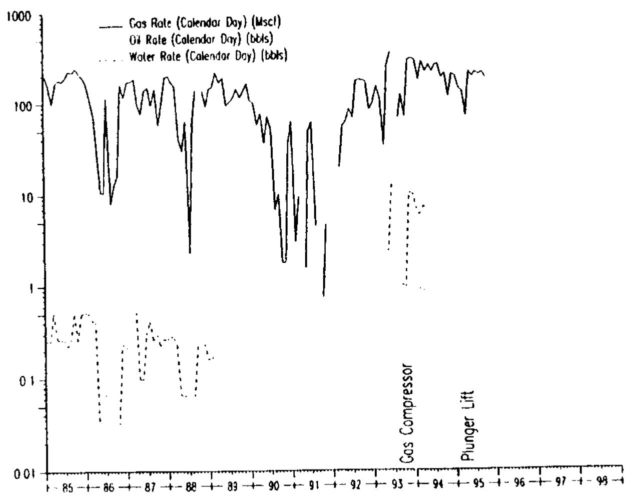


Figure 7 - State Com K 00007A

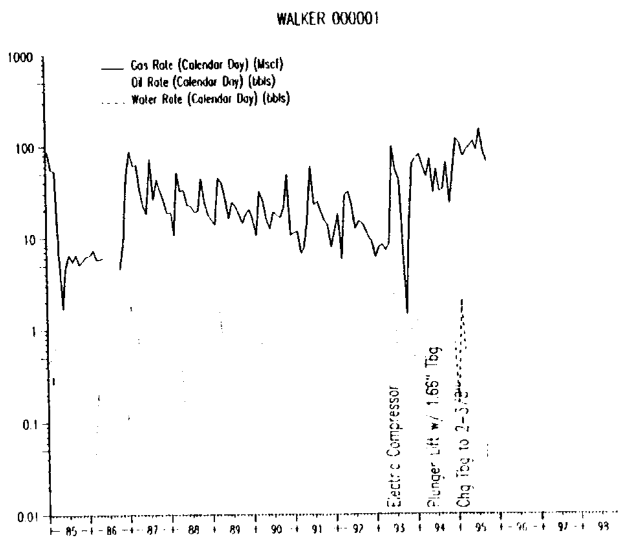


Figure 8 - Walker 000001