# DO I NEED A PLUNGER?

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## INTRODUCTION

A plunger is installed in a gas well for a basic reason: to remove the back pressure on the formation due to liquid accumulation, which has the effect of reducing production. Any restriction on formation draw down diminishes the pressure differential between the formation and the wellbore. As a result, the driving force that propels production is likewise reduced. The causes of the pressure loss may be related to formation problems or well bore concerns. The former may be due to a natural loss of reservoir pressure and subsequent loss of energy required to remove liquids. The latter may be from restrictions such as scale, paraffin, or other mechanical problems. A plunger can help remove the restrictions that reduce flow and help restore a well to its expected decline rate. However, the application must be carefully chosen in order to ensure it is successful. Tools are available that allow one to identify potential plunger lift candidates. In addition, the operation of the equipment must be optimized and maintenance should be periodically performed to allow the system to operate as designed.

## CANDIDATE CHOICE

There are several indications a well has lost its ability to naturally remove the fluids that accumulate in the wellbore. The question becomes: Is the well loaded, or is there another reason for the lost production?

The first screening tool one might consider is the flow rate as it relates to critical velocity. At, or near this point, the rate is insufficient for fluid removal and loading begins. Critical velocity charts are available and are easily read for a particular well pressure and tubing size. The two generally used charts are based on findings from Coleman and Turner, with the Turner calculations reading 20% higher than Coleman's.

Another sign of loading is an increase in the pressure difference between the casing and tubing while the well is flowing. Due to liquid hold up in the tubing, the reservoir pressure on the backside increases to counter act the higher density fluid in the tubing. If there is a large difference between the tubing and casing, or if the differential begins to increase, the well may be loading.

There are other signals of loading that should be watched. Is the well slugging, as characterized by intermittent flows of copious volumes of fluid? This shows pressure build up in the annulus and its subsequent decrease when expelling liquids. Is the well erratic or is the decline rate more severe than normal? When coupled with a well near its critical velocity, this is a good indication of loading problems.

## CONFIRMATION

Following the presumption the well is loading, confirming steps can be taken to better ensure the application will be successful. Several of these items are:

1. Run a broach or gauge in the well to remove obstructions. Scale, paraffin, or crimped tubing may be the reason the well is loading and should be remedied first. Running a plunger will not alleviate the problem. Ideally, tag to determine if there is an obstruction before running other tools.
2. Run a fluid pressure gradient. This is quick way to determine if there is a definite gas-liquid interface and its level. A word of caution, though. Many times, the well will not have a stagnant liquid level, but will be flowing in slugs. The gradient may not indicate this. The fact that there is not a concrete fluid level does not preclude the fact the well is loading,
3. Swab the well. If liquid is recovered and the production increases, there is a loading problem. Also, this will give a good indication of the production increase from the well,
4. Batch treat the well with liquid foamer. This is a cheap and easy way to determine if fluid can be lightened enough for removal (of course, this is also a possible alternative to plunger lifting). One should conduct the calculations and testing to determine if foamer will work. However, with sufficient help from a qualified chemical supplier, experience shows a quick field test may be adequate,
5. A common rule of thumb is the expected unloaded production of the well. If a well produces a GLR of 400 $ft^3$/bbl of liquid per 1000 feet of depth, it is likely capable of operating with a plunger.

## EQUIPMENT

Once loading has been confirmed and one is relatively assured the candidate is valid, the process of choosing the correct equipment begins. There are some basic items that are always required; a lubricator, a plunger, and a valve on the flow line. The setup can be as simple as manually adjusting the well on site, or as complex as a self adjusting controller that changes set points based on well conditions and relays the information to a remote location.

Controller- From basic to complex, some of choices are:

1. A timer (e.g. Nighthawk), which merely allows a pneumatically operated motor valve to open and close at a pre-set time.
   A pressure switch (e.g. Murphy switch), which allows the motor valve to open and close based on the well pressure. A timer and pressure switch can be used concurrently.
2. Controllers that look for pre-set conditions, such as flow rate and well pressures to determine when the motor valve opens, how long it remains open, and how long the well should be shut in.
3. Controllers equipped with radio communication. This allows for quicker response from the optimizer and better analysis of operations.
4. Self adjusting controllers ('Smart Controllers') have the capability of adjusting the set points to ensure the well is optimized. They may observe the speed of the plunger or the casing pressure and make the appropriate change to ensure operation stays within a specified window.

Valves- Generally, a pneumatically operated motor valve (e.g. Kimray) on the flow line just downstream of the lubricator.

Pressure Transducer- Depending on the complexity of the system, there may be transducers on the casing, tubing, flow line, and a differential transducer on an orifice plate.

Lubricators- Should be pressure rated for maximum shut in pressure and should be NACE rated as required in sour conditions.

Downhole Bumper Spring- Generally installed in the seating or profile nipple, this device cushions the fall of the plunger to prevent damage to it as it reaches the specified depth.

## PLUNGERS

These are possibly the most integral part of the system and should be chosen carefully for the expected condition. Some of the types used are:

1. Pad plunger- this plunger has spring loaded pads on the sides that maintain contact with the tubing wall. Thus, they seal well and last longer than other types. The pads can be re-dressed and the plunger reused. They should not be used in high paraffin wells, because the moving parts can become stuck and render the plunger inoperable.
2. Solid plunger- Generally simply a metal cylinder which, in some cases, is hollowed out to reduce weight and cost. Grooves can be machined into the outside diameter, resulting in a spiral type of plunger. They do not seal as well as the pad type and are better used in trashy or paraffinic wells.
3. Brush plunger- This is a solid plunger that has been covered with a nylon bristle material. When new, this plunger is the best sealing, which makes it good for cleaning the tubing. The plunger becomes less efficient as the brushes wear out.
4. Free Falling/Bypass plunger- These come in various brands (e.g. McLain, Weatherford, ILS, etc.), but the operation is similar. They are one piece plungers with holes machined in the bottom and a shifting rod protruding downward. The holes allow fluid to circulate through the plunger, achieving a faster fall rate, less down time while the well is building pressure, and increased production.. Upon contact with the bottom hole spring, the rod is pushed upward, closing off the flow and allowing the device to travel upward when the motor valve is opened. Experience shows the rod can close prematurely, resulting in poor operation and quicker arrivals, which can damage the lubricator.
5. Two Piece (Pacemaker)- This plunger has a cylinder that is machined out in the middle and a metal ball that fits into the bottom. When the ball makes contact with the cylinder, the resulting seal allows the gas to push the plunger back to the surface. A rod in the lubricator releases the ball, allowing it to fall. The cylinder remains in the lubricator as long as required, at which point the motor valve closes momentarily to let it fall. When the cylinder meets the ball at the bumper spring, the plunger again rises. The advantage is very little downtime, which maximizes and evens out production. Fluid is removed in small quantities, as opposed to larger slugs with conventional plungers. At times, the plunger can catch the ball, resulting in fast arrivals. However, different metallurgies are available that result in the correct fall time of ball and plunger.

6. Two stage plungers- Two plungers are placed in the well at prescribed depths with the theory that less pressure is required to lift them, if there is less hydrostatic head to lift. They can be used in wells that show a high required pressure build up and in wells that have slow plunger arrival times.

## OPERATION

The operation of a plunger is a little more than just allowing the device to run without concern or adjustment. In order to unload the well and operate it safely, certain items should be observed and changed when required.
One parameter to watch is the plunger fall time. This is important because it is essential that the plunger reach the bumper spring in order to ensure all fluid is lifted and to prevent a quick return that can damage the lubricator. Different plungers fall at different rates, so there is not one rate that is applicable to all systems. A general fall rate the author uses is 250 ft/min for a pad plunger. Of course, the bypass and two piece plungers fall at a much faster rate. The fall rate can be determined through published guidelines, following the plunger with fluid level shots to determine the location, or field adjustments until best operation is acquired.

Another variable that should be watched closely is the plunger arrival time. As a compromise between fluid leakage with slow traveling plungers and damage due to quick arrivals, a general range for conventional plungers is between 500 ft/min and 1000 ft/min with an average 750 ft/min. The arrival time can be adjusted in several ways: by adjusting the pressure at which the motor valve opens, by changing the point at which the valve closes (differential flow rate), and by changing the flow time.

Tubing placement in the well is important in removing fluids due to the pressure exerted by a column of fluid and its ability to be lifted. Tubing set above the perfs invites a situation where the critical velocity in the casing below the tubing is even higher than in the tubing. The plunger does not have access to lifting this liquid and the well can remain in a state of partial loading. If the tubing is placed below the perfs, a liquid level will form that fills the casing and tubing when the well is shut in. At startup, the well must remove the fluid in the tubing and annulus, a much more difficult task than removing fluid in the tubing only. An accepted location to land the tubing is about 1/3 of the way in the perfs.

## MAINTENANCE

Proper maintenance of the system is important if one desires optimum performance. A primary area is the care and inspection of the plunger and spring inside the lubricator. As a mechanical device, the plunger wears with use and time and becomes more inefficient, allowing fluid to leak by. In addition, moving parts on pad and by pass plungers are susceptible to failure and can result in fishing jobs should they become loose in the well bore. The plunger should be periodically pulled from the well and its diameter measured with a micrometer. An average reading should be determined and the plunger should be replaced or redressed when a specified point in reached.
The spring in the lubricator is constantly called on to cushion the upward force from the speeding plunger. It too is prone to damage and should be on a schedule to check its condition. At the very least, it should be visually inspected and replace should it be found broken, cracked, or chipped. The elasticity of the spring is also a concern and although visual damage might not be seen, the performance may have reached a point of inefficiency. Thought should be given to the periodic replacement of the spring regardless of its visual condition.
The bottom hole spring assembly should likewise be checked. This process is more difficult, because it must be removed via wireline, a more expensive and time consuming operation than checking the plunger and lubricator.

## CONCLUSION

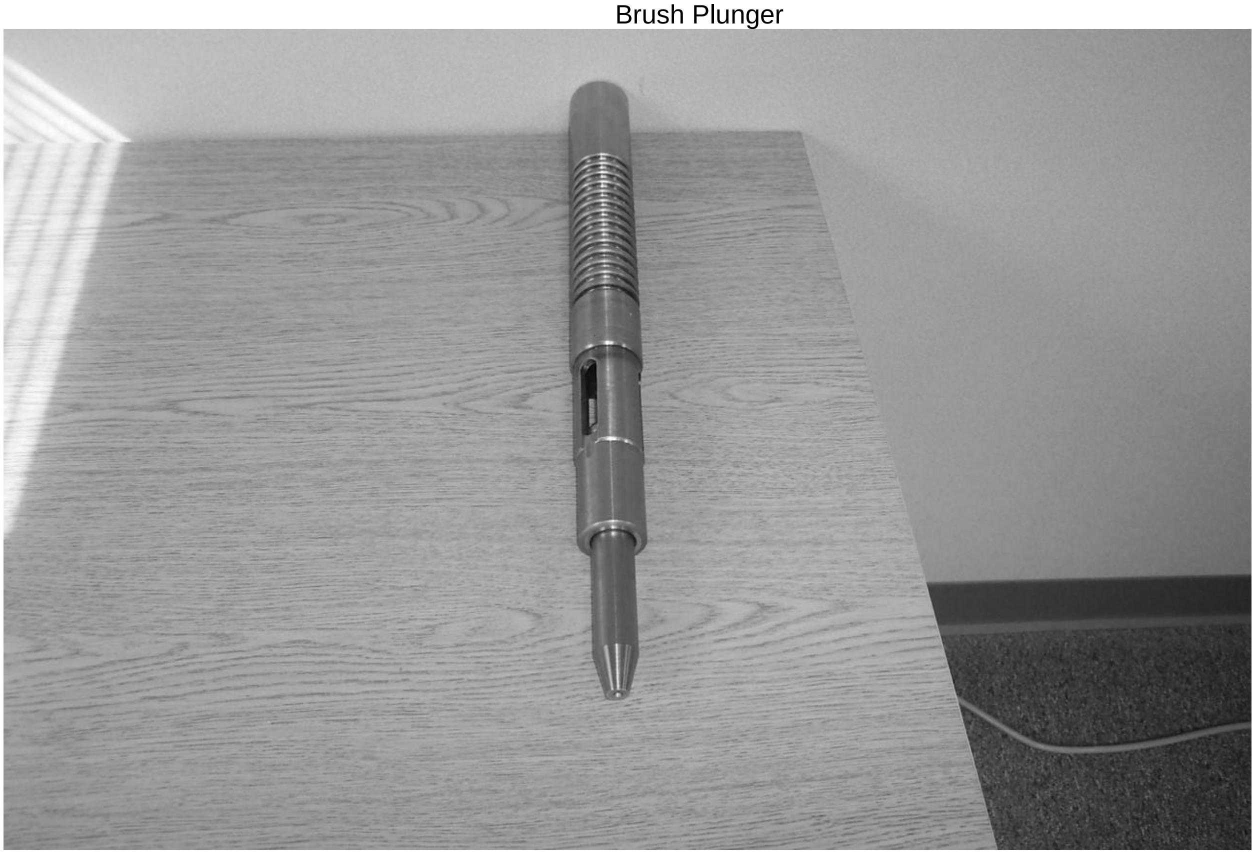
The successful installation of a plunger lift can be a simple process, with little thought given to the application or its maintenance, or it can be a more thorough and complex issue, with concern and effort given to choosing the proper candidate, researching the facts, and installing the correct equipment. Although the former situation might prove successful from a hit or miss proposition, the latter will show that the well will function in a more reliable manner and yield a smoother operating system. It may prove more expensive and time consuming up front, but will result in a system that will return a greater yield on the investment and longer life to the well.

Standard Plunger Lift Installation


Pad Plunger


Solid or Spiral Plunger

Brush Plunger



Free Fall/Bypass Plunger

Two Piece Plunger