PLUNGER 101: BASIC PLUNGER LIFT

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When gas wells no longer have the pressure or energy to produce their fluids to surface they are liquid loading. Liquid loading drastically reduces both gas and fluid production as the fluid builds up in the bottom of the well bore. As the well tries to produce both gas and fluid in a loaded condition the wells production will continue to decline rapidly until the well basically kills itself and stops production. Liquid loading causes this decline for two reasons, one the reservoir has to overcome the hydrostatic head of fluid to produce gas, meaning it just slugs or bubbles through. And two as the well continues to produce it brings more fluid into the wellbore that can't make it to surface, which adds to the hydrostatic head, further reducing production. Eventually the hydrostatic head or pressure from the fluid at the bottom of the well will be too much for the pressure of the oil or gas reservoir to have any production.

There are many ways to identify liquid loading in both the field and in the office:

1. Decline Curves - One of the first ways to identify liquid loading is to look at the wells production decline curve. If you have a graph of the gas and liquid production numbers over a time period liquid loading can be identified by a sharp drop off in the gas and liquid production of the well (Diagram #1). In a normal lifecycle of a well, the production should decline at a steady rate, when it drops off this steady rate drastically this is a good indication of liquid loading.

2. Differential Pressures between tubing and casing - As the well begins to liquid load, fluid will build up at the bottom of the well preventing the communication between the casing and tubing. Typically on gas wells the well will produce with the casing valve closed, therefore as the well liquid loads, the casing pressure will increase and the difference in flowing pressures between the tubing and casing (differential pressure) will also increase. With an unloaded well the tubing and casing pressure should be similar, for example a 500 kpa reading on the tubing should have a corresponding 500 kpa reading on the casing (assuming there is no packer or other restriction or blockage in the well), meaning there is communication between the two. When the well loads up the differential pressure will increase, for example a 500 kpa reading on the tubing may correspond to a much higher reading such as 800 kpa on the casing. Differential pressure however should not be the sole factor in looking at liquid loading as there could be other factors that lead to this difference such as a restriction or blockage in the casing or tubing.

3. Sharp decrease in Fluid production – Another indication of liquid loading is a sharp decrease in not only gas but fluid production in the well. Most operators will think that a decrease in fluids especially water is a good thing as it reduces the facility and transport costs. However, a well should have a fairly consistent Gas to liquid ratio. When a well starts loading it means it is unable to lift fluids to surface consistently or it has dropped below its "critical rate" and more fluid will remain down hole. This means as the reservoir continues to produce, some gas will make it to surface but most of the fluid will build up at the bottom of the wellbore. This fluid then in turn creates a large liquid column or hydrostatic head and continues to reduce the production of gas to the surface. Therefore fluid production should be monitored closely as well.

4. Sporadic or Inconsistent Production - When a well does start to liquid load it is also going to have sporadic or inconsistent production. When a well is not liquid loading production will be fairly consistent as the well will produce all the gas and fluids that come into the wellbore, but as a well starts loading it will also start "slugging" the fluid. Meaning it will produce a bit of gas and fluid but then will not have enough energy or pressure to break through the fluid colomn that has built up on the bottom of the wellbore. So then production will stop until enough energy or pressure builds ups to break through this column of fluid. When the pressure/energy has built up then you will get a "slug" or a short period of production, which carries some of the gas and fluid to surface. This cycle will repeat itself with the shut-in periods getting longer as the fluid column gets larger and the well needs to buildup more pressure/energy to slug the production through this hydrostatic head. Eventually without solving this the well will reach a point where it cannot build up enough energy to break through the liquid column that is in the well bore thus "killing" the well.

5. Current Operating procedures - Most wells that are liquid loading don't get noticed right away, most wells have been liquid loading for a period of time before possible long term solutions start getting looked at. One of the best ways to determine if a well is liquid loading is to examine how it is being operated now. Many operators will implement short-term solutions to liquid loading as part of there operating procedures without recognizing a

long-term problem or solution. Many operators start manually “Slugging” or “stop-clocking” there wells when they see a sharp decrease in production. Meaning they will continually shut-in and produce a well periodically, allowing the well to build up enough energy during its shut-in periods so it can produce during its open periods. For example, operators may go to a well every morning to open and produce the well during the day but then return to the well each night to shut it in to build up and recover. Other operating procedures might be periodically swabbing all the fluid out of the well, dropping soap sticks or periodically venting the well to atmosphere.

Plunger lifts are one of the most cost effective and efficient solutions to lifting fluid in oil and gas wells. A plunger is a solid piece of material that creates an interface between the gas (below the plunger) and the fluid column that has built up on the bottom of the well bore (above the plunger). When a plunger is dropped it will travel to the bottom of the tubing and fall through all the fluid until it reaches the bottom of the well. The outside diameter of the plunger is similar in size to the inside diameter of the tubing, which allows for a friction seal. Therefore when the plunger travels up the tubing it carries most of the fluids above it with very little slippage of fluids down the sides. When the plunger reaches the surface it carries all the fluid with it thus unloading the well. In most cases plungers do require some shut-in time for the well to build up enough energy to drive the plunger as well as all the fluid above it to surface. The amount of shut-in time required is based on the needs of the well and can be controlled through a basic timer, controller that is programmed for plunger lift or operated by an existing Scada system.

Plunger lifts are not the answer in all wells as they do have limits. Some rules of thumb that can be used to estimate if a plunger lift will work are that it has a least 400 cubic feet of gas per barrel of fluid per 1000 feet of lift (or 1.75 E^3M^3 per $1M^3$ of fluid per 1000 meters of lift). Also that the shut-in wellhead pressure of the well is at least 1.5 times the sales line pressure. There are also many types of well-modeling software and equations that can be used to evaluate the wells and calculate how much energy is required to lift a certain amount of fluid with a plunger. The most widely used equations were originally developed by Foss and Gaul[1] in 1965 (Equations 1 & 2). They basically looked at all the major factors that were acting on the plunger and what amount of energy (casing pressure) was needed to drive that plunger to surface. Foss and Gaul calculated the minimum casing pressure required as well as the average and maximum casing pressures. Abercrombie then took the calculations developed by Foss & Gaul one step further and developed an equation to determine the amount of gas required to lift the plunger and liquid at each cycle (Equation 3). These equations allow operators and plunger companies today to optimize and evaluate if plunger lift is the right solution for their wellbores.

There are three sources of energy or gas volume that are used to drive a plunger lift system to surface, 1. The formation, 2. Storage area (Annulus) 3. Gas Injection

1. The main form of energy used to lift a plunger is the formation. Sometimes the formation will have the ability to deliver a large amount of gas directly in to the tubing to keep the differential across the plunger high enough to keep it traveling to surface. This usually happens when a well just starts liquid loading and can operate with a continuous flow plunger that is constantly traveling with very minimal shut in time. When the formation while producing does not have enough energy to get a plunger to surface then the well requires some shut in time allowing energy to be built up between the reservoir and the bottom of the well. How quickly the well can build up this energy is a determining factor on how long the well has to be shut in for.
2. The second source of energy is the storage area which is the annulus or the area between the casing and the tubing (used in wells without packers). If the well is being shut-in this area is used as an accelerator, as the formation charges up the storage area with high pressure gas. Then when the well is opened to line the sudden pressure loss in the tubing becomes a void and the casing gas rushes into the tubing to fill the void thus forcing the plunger and fluid above the plunger to surface.
3. Gas injection (gas lift) can also be used in combination with plunger lift if the formation and storage area does not provide enough energy to drive the plunger to surface. In this case gas is injected down the casing providing the extra energy need.

Another factor in how efficient the plunger is and how much energy is required is the plungers sealing capability and the amount of gas slippage it allows past the seal face of the plunger. There are many different types of plungers on the market and are summarized below:

1. Padded Plunger – The padded style plunger is one of the most common types of plungers as it has spring loaded pads that press onto the walls of the tubing. Although the pad plunger has a metal to

metal seal, its ability to expand and contract following the tubing ID allows this plunger to be very efficient. In well environments with solids (sand/scale) or large amounts of paraffin this plunger may not be as effective due to the fact that the solids and paraffin get behind the pads and make them unable to expand or contract.

2. Brush Plunger – The brush plunger is one of the most efficient sealing plungers due to the long seal area that can expand to the maximum ID of the Tubing. The brush plunger was designed to run in wells that had a large amount of produced solids in the well as the brush is able to sweep the tubing walls clean while not hanging up on the small particles in the tubing
3. Solid Plunger – The solid or bar stock plunger is one of the least efficient plungers at lower velocities due to the ridged seal face which requires the plunger OD to be under sized in order to keep it from hanging up on tubing imperfections. These ridges however are very effective in keeping the tubing walls clean of paraffin as its ridged seal face knocks the paraffin off allowing it to come to surface with the produced fluids.
4. Bypass or Flow-Thru Plungers – Bypass plungers are normally a preferred option over conventional plungers when a well has enough energy to sustain them. Bypass plungers have holes in them allowing the plunger to fall against the flow of gas (the gas "flows through" or bypasses the plunger) on the way down. When a bypass plunger hits the bottom of the well there will be some sort of mechanism that closes these holes or ports, making the plunger seal and forcing it to seal and rise with producing gas and fluids.
5. Flexible (Coil-tubing) plungers – Flexible plungers were designed to overcome the problems associated with using rigid plungers in coiled tubing and directional holes. These plungers have a cable inner mandrel that bends to conform to the pipe curvature. In many seemed coil applications a brush coil-tubing plunger is used for a better seal around the welded seam on the ID of the coil. Flexible plungers can also be used in conventional (tubing) applications where regular plungers get caught in the tubing due to a tubing crimp etc..
6. Internal shock absorbing plunger – The internal shock absorbing plunger is a plunger that was designed for wells that the down-hole assembly (which normally absorbs the shock of the plunger at the bottom of the well), was acting as too much of a restriction. On some applications the bottom-hole assembly or spring would get too much solid or paraffin build up on it and would choke back the flow of the well. With an internal shock absorbing plunger, the plunger has an internal spring in it and therefore can be used without a down-assembly.

The biggest change in plunger lift assemblies over the past few years has been the controller technology and how the plunger programs are managing well operations. When plunger lift was first introduced it was just operated with a basic timer which would open and close a motor valve (opening and closing the well) allowing the plunger to rise and to fall the length of the tubing. The problem with basic timers is that there is a lot of guesswork required to set up the right open (flowing) and close (shut-in) times. If too long of a close period is entered the long recovery time may cause the plunger to come up too hard at surface and there is a risk of damage to the wellhead, surface equipment and plunger. Long shut-in times also mean that there is less time that the well was actually producing. If too short of a close period is entered the plunger may not reach the bottom of the well or might not have enough energy to reach surface successfully with all of the fluid above it. When a plunger does miss a cycle or stalls before it reaches surface it will also have difficultly on any subsequent cycles. Because the timers settings are consistent it will always shut-in for a set time regardless of the amount of fluid build up. When the plunger misses a cycle it doesn't bring all the fluids to surface yet is still producing more fluids. So on the next cycle the plunger will have the same amount of shut-in time but more fluid on top than it had previously (when it missed a cycle) which limits its chances of success.

The most common type of controller today is a timed based controller that has a few more functions than a basic timer. First of all the "open time" is broken into two sections, one being a "plunger arrival time", and two being an "after-flow" time. The plunger arrives at surface and passes a sensor on the wellhead and the open time switches from the plunger arrival time to the after-flow time. If the plunger does not reach surface during the allotted plunger arrival time, a time out has occurred, then the controller switches into a "mandatory shut-in" mode which prevents the well from producing any longer and shuts the well in for an extended period of time that is set by the operator. The mandatory shut-in mode acts as a back-up for an unexpected change in well bore conditions such as a line pressure increase or more than expected fluid being produced by the well for that time period. When an operator checks on the well he can see how many times a controller had to go into the mandatory shut-in mode and then adjust his times accordingly.

The next improvement on controllers was when “self-optimizing” controllers were introduced which makes changes to the controller on its own depending on the constantly changing well conditions. The two types of self-optimizing controllers are self-optimizing on time and self optimizing on pressures. The self-optimizing time controller monitors the plungers last arrival times and uses this information to decrease the shut-in time and increase the after-flow time based on the plunger speed target windows in the program. The next type of self-optimizing controller, self-optimizes on pressure, where there are two pressure transducers hooked up to the casing and the sales line. When a well is unloaded the casing and tubing pressure should be the same as there is communication between the two at the bottom of the well bore. As the well starts loading the casing pressure will start increasing over the tubing pressure due to liquid accumulation or hydrostatic head buildup (differential pressure). The self-optimizing pressure controller has a function called a “casing dip” mode which can be set by the operator. When the casing dip mode hits that pressure (for example 5 psi casing back pressure), that is when the controller shuts-in the well. This allows the well to produce or flow until it’s loaded and can adjust accordingly. The second pressure transducer on the sales line monitors the sales line pressure so for example if there is a line pressure increase the controller would know that it needs more shut-in time, or build-up energy to drive the plunger to surface.

Other types of equipment that are also required on most plunger installations are a down-hole assemblies, motor valves, sensors and lubricators.

Down-hole assemblies – A down-hole assembly contains a spring that absorbs the shock of the plunger when it reaches the bottom of the well bore and then some type of “hold-down” that keeps the spring from coming up the well when the well is flowing. Hold downs consist of a down-hole profile with seals or a “tubing stop” or “collar stop” if no profile exists or the assembly is desired somewhere else in the well bore. Down-hole assemblies also sometimes have a check-valve (ball and seat) in them. The check valve allows fluid to come up into the tubing but does not allow the fluid to fall back down, thus holding the fluid in the tubing for the plunger cycles. The reason not all wells contain them is there is the risk of having too much fluid above the spring that the plunger could not lift (on a missed cycle etc.) and the operator occasionally having to intervene with some other solution.

Motor-Valve – Is a valve that is used to open and close the well causing the plunger to rise and fall

Sensor – Contains a magnet and allows the controller to know when the plunger reaches surface (when it passes the sensor).

Lubricators – Are installed on top of the wellhead and contain the spring to absorb the shock of the plunger when it reaches surface as well as a “catcher” that can catch the plunger at surface to be inspected. Catchers can be just manual where an operator has to screw it in when he is on location. Or an “Auto-catch” is installed which is a catch that is hooked up with an extra motor-valve that is activated by the controller. The benefit of an auto-catch is that it catches the plunger at every cycle and holds it away from the flow-line. When there is no auto-catch on the lubricator the plunger just fluctuates on differential pressure around the flow-line, and can cause damage to the plunger or choke the well back.

There are many advantages to using plunger lift as a solution to liquid loading such as its low cost in relation to pumping units or tubing changes. There is also no external energy required as the plunger uses the wells own pressure and it can produce many wells to depletion. Some of the new developments in plunger lift are staging plungers (putting two plungers in the same well bore) as well as having a plunger with a pressure and temperature recorder inside it to look at well bore conditions. Plunger lift is becoming more and more popular with operators and with these new developments it will probably be seen in more and more wells.

REFERENCES

[1]Foss, D.L. and Gaul, R.B.: “Plunger-Lift Performance Criteria with Operating Experience - Ventura Avenue Field,” Drilling and Production Practice, API, (1965), pp. 124-140

[2]Abercrombie, B.: “Plunger Lift,” The Technology of Artificial Lift Methods, Vol. 2b, by K.E. Brown, Pennwell Publishing Co., Tulsa (1980), pp. 483-518.

[3]O’connell T.: Plunger Lift: Production Control Services Inc., (1998), pp. 5-7

Equation #1- Minimum Casing Pressure (Foss & Gaul)

$$P_{cmin} = [(P_p + P_{lp} + P_a + (P_{lw} + P_{lf}) \times L) \times (1 + (D/K)]$$

Where,

P_{cmin} = minimum casing pressure required
P_p = pressure required to surface the plunger (5 psi)
P_{lp} = sales line pressure or wellhead pressure
P_a = atmospheric pressure (14.7 psi)
P_{lw} = pressure required to surface 1 bbl of liquid
P_{lf} = pressure loss due to liquid friction
L = barrels of liquid
D = tubing or tubing stop depth
K = pressure loss due to gas friction

Where, K and P_{lw} are approximately constant for a given tubing size:

	K	$P_{lw} + P_{lf}$
2 3/8 =	33500	165
2 7/8 =	45000	102
3 ½ =	57600	63

Equation #2 – Average (2a) and Maximum (2b) casing pressures (Foss & Gaul)

$P_{cavg} = (1 + (A_t / (2 \times A_a))) \times P_{cmin}$ (2a)
$P_{cmax} = ((A_t + A_a) / A_a) P_{cmin}$ (2b)

Where,
P_{cavg} = average casing pressure during operation
P_{cmax} = maximum casing pressure build-up before operation
A_t = Area of tubing (sq. ft)
A_a = Area of tubing/casing annulus (sq. ft)

Equation #3 – Gas Required per Cycle – Abercrombie

Mcf/Cycle = $C \times D \times P_{cavg}$

Where,
C = Constant for each tubing size
2 3/8 = 0.000001934
2 7/8 = 0.000002904
3 1/2 = 0.000004350
D = tubing or tubing stop depth (ft)
P_{cavg} = average casing pressure during operation

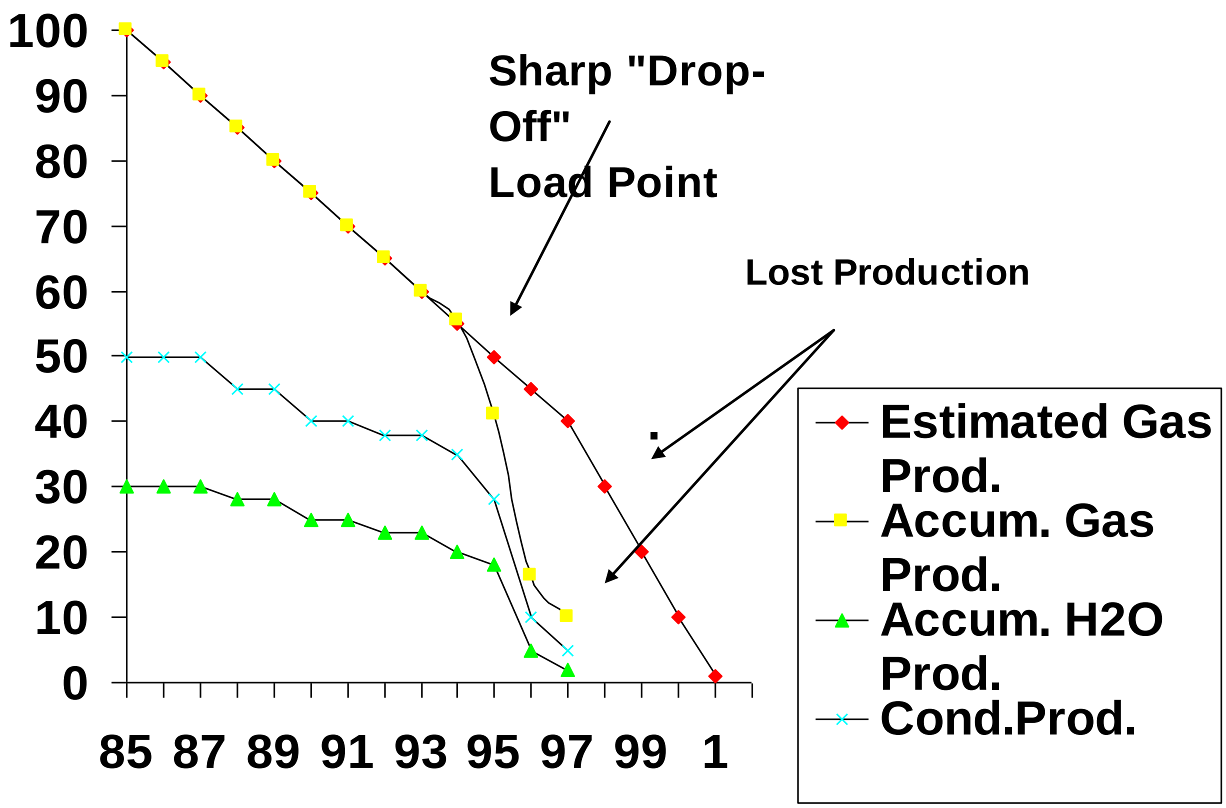

Diagram 1 – Production Plot

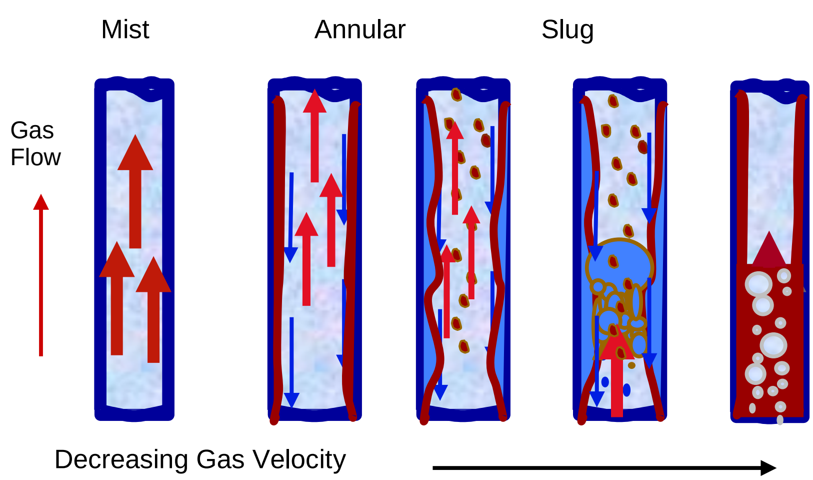

Diagram 2 – Gas Well Loading Flow Regimes