PLUNGER LIFT, GAS ASSISTED

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Abstract

After decades of trial and error, and frustration, plunger-lift finally has become widely accepted as a legitimate solution to producing many wells. As the experience level has increased, so has the success. As the equipment has been improved, so have the applications.

This paper is to describe an application, coupled with new technology, that is allowing producers to use plunger-lift systems on wells never before possible. The limiting factor for most plunger-lift wells is gas. It is now possible to take advantage of the low lifting costs of plungers on some of these wells.

Introduction

Marginal flow characteristics of many gas and oil wells make it impossible to produce them without some type of artificial lift. As ratios and pressures change, it becomes necessary to consider the options for continued production. Of the many types of artificial lift available, plunger-lift is clearly the most economical. In terms of equipment costs and cost of operation, it stands alone. The problem is that it is not appropriate for all wells. There are limitations that prohibit using this type lift on many wells.

Text

One of these limitations is total fluid produced per day. Typically the most successful candidates are those that produce less than 100 barrels per day. Certainly there are exceptions, but because of the cyclical, intermittent operation of a plunger-lift system, and the time needed for a pressure build-up, it is difficult to make enough cycles to produce more than 100 barrels per day.

Another limitation is gas. Successful plunger-lift operations depend on gas. There is no depth limitation as long as there is sufficient gas available to drive the plunger to the surface. As a bare minimum, the well must be capable of enough gas volume to push the plunger to the surface each cycle. It must also be capable of building sufficient pressure to push the plunger, along with the liquid above it, to the surface. Normally there is system back-pressure that must also be overcome to reach a high enough pressure differential to cause plunger movement.

The typical system has a bottom hole shock spring and stop located inside the tubing. Normally this is at the bottom of the well. On the surface, above the master valve, is a catcher and lubricator. The lubricator serves as an upper limit for the plunger's travel, and absorbs the shock as it reaches the top. The plunger is a free traveling piston that runs between the spring at the bottom and the spring in the lubricator. The movement of the plunger is controlled by a diaphragm-actuated valve (motor valve) and electronic controller. These are mounted on the flowline.

A typical cycle starts with the plunger resting on top of the spring at the bottom of the well. At this point there will normally be a head of liquid (oil, condensate or water) above it. The well is shut-in during this period. It is important that this shut-in time be long enough for the plunger to fall from the surface to the bottom, and for a sufficient pressure build up to push the plunger and liquid load to the surface. Ideally, in this application there is no packer. This allows the annulus to become a volume chamber in which to store gas during this shut-in period. Once there is sufficient pressure, the motor valve on the flow line is opened. This opening is signaled by the electronic controller. By opening the motor valve, the head gas (gas in the tubing above the liquid slug) is produced. As the head gas is evacuated from the tubing, a differential is created across the plunger and the liquid slug above it. This differential allows them to start moving toward the surface. The gas that has been stored in the casing annulus then feeds in beneath the plunger, pushing it to the surface. In the case of an oil well, it is normally shut-in as soon as the plunger reaches the surface, thus saving some of the drive gas for the next cycle. For a gas well, it is produced for a longer period of time after the plunger reaches the surface. The motor valve is then closed, allowing the plunger to fall. These cycles are repeated several times each day.

The cycling times for such a well can be determined by several methods. Pressure, differential, time, velocity, and several combinations. The preferred method has become velocity. The speed of the plunger as it travels to the surface is the key to its efficiency. Since a plunger does not have a perfect seal, there is gas movement past the plunger during it's ascent. If it is traveling too slow, not only does it waste lift gas, but could possibly "stall out" if the differential diminishes. If it is traveling too fast, it is hard on equipment because it strikes the surface too hard. It is also inefficient, thus negatively effecting production. With microprocessor-based controls, it is very easy to monitor velocity, and make appropriate cycle changes if the plunger is traveling outside of an acceptable range.

All of this is fine for those that meet the right criteria for plunger-lift. Of all the limiting factors in this operation, gas is the biggest. It takes gas to run a plunger. Most plunger-lift candidates lack sufficient gas to run a plunger without the additional volume from the gas in the annulus, however, with "high efficiency" seals more progress is being made in this area. It is for this reason that the casing annulus is used for gas storage. The gas that is stored in the casing annulus is the "horsepower" for this lifting operation. Interestingly enough, it does not matter where that gas came from. It can be from the formation or it can be from an outside source.

In a project started in 1992, in Argentina, sufficient gas was not available to produce many of the wells in the Cañadon Leon field. With wells that produce a heavy crude, and a gas with a high CO_2 content a test project was started to attempt plunger-lifting. The wells in this area are on very tight spacing, and had been typically produced by rod pumping. Most had been experiencing various problems because of the free gas. Stroke inefficiency, and outright gas locking was not unusual. Some wells produced enough gas that rod pumping was almost out of the question, however, most have been produced in this fashion. There are several wells in this area that are very high-volume gas producers. Because of the availability of extra gas from these wells, and the close spacing, the "injection option" software was created.

The plunger-lift systems used were conventional 2 7/8" systems, using plungers with high efficiency seals . A gas line was run from the gas source (other wells), to the casing on the wells to be lifted. The only difference in the standard plunger-lift equipment was the addition of an extra motor valve, mounted on the gas injection line. This allowed control of the injected gas

The software, called the "Auto-Cycle, Injection Option" was written so as to utilize automatic well control via tracking plunger velocity. This meant that the controller would change the well cycles if the plunger was traveling outside of an acceptable window of operation. In addition to the normal cycle changes, the controller would also change the injection gas. If the plunger did arrive outside of the operating window, the controller would increase or decrease injection gas. In order to slow the speed of the plunger, injection gas was decreased, to increase the speed of the plunger, injection gas was increased.

One key element was to be rather stingy with the injection gas. Injecting only as much as needed was critical. Overpressuring the annulus meant increasing the back pressure, thus restricting inflow. In order to keep this from happening, the injection time changes were set up in increments of minutes:seconds.

There were some wells that required almost"full time" injection to operate effectively, however, most required only a few minutes. The charts show typical production rates and cycle times.

Conclusion

Since beginning this project in 1992, it has been expanded to three other areas within Argentina. Other projects in East Texas and Oklahoma have also shown favorable results. It has effectively increased the likely candidates for plunger-lift. For wells without sufficient gas, and for wells with higher liquid volumes plunger-lift is now possible. The key ingredient in the plunger-lift formula remains gas.

East Texas

This well was already on plunger-lift. Due to falling production injection gas was added to keep it producing.

Depth	Production Before Injection Gas	Liquid After	Gas After (net)	Gas Injected
8811	8 bbl/d, 100 mcf/d	14 bbl/d	248 mcf/d	79 mcf/d

This well came on-line producing 1.3 mmcf/d. In 8 years it dropped off to approximately 50 mcf/d. There was not sufficient gas to operate a plunger-lift system, so additional lift gas was provided when the system was installed. The extra gas made the system function effectively. The current data is as follows:

Depth	Production Before Plunger-lift w/ Injection	Liquid After Plunger-lift	Net Gas Production	Gas Injected
9005'	0 bbl/d, 50 mcf/d	7 bbl/d	150 mcd/d	120 mcf/d

Argentina

None of these wells could be produced on plunger-lift without augmenting the lift gas. The gas volumes and pressures were not sufficient to operate on the wells own energy alone. Some of these wells utilized gas lines for external gas, others used gas directly from another producing well. Because of different operators reporting well data, the same data was not available for every well.

Mendoza (Argentina)

Depth	Production Before P/L	Production After P/L	Injection Pressure	Injection time
7488	32 bbl/day	76 bbl/day	620 psi	2 minutes
6910	25 bbl/day	39 bbl/day	327 psi	1 minute

Cañadon Leon (Argentina)

Average Depth	Production After P/L	Injection Time	Injection Pressure	Casing Pressure
5300	22 bbl/day	2 Minutes	650 psi	400 psi
5000	9.4 bbl/day	5 Minutes	360 psi	280 psi
5248	6.29 bbl/day	5 Minutes	400 psi	400 psi
5800	17.6 bbl/day	1 Minute	380 psi	250 psi
5100	49 bbl/day	15 minutes	650 psi	460 psi

Neuquen (Argentina)

Field	Well Number	Depth	Production/Day
Centenario	1049	6888	37.7 bbl/day
Rio Neuquen	162	9121	25 bbl/day
Rio Neuquen	8	8102	69.19 bbl/day
Rio Neuquen	215	7334	31.45 bbl/day
S. Barrosa	75	6081	37.7 bbl/day
S. Barrosa	21	6002	37.7 bbl/day
S. Barrosa	53	6327	50.3 bbl/day
Campamento	60	2192	100.6 bbl/day
S. Barrosa	48	6320	75.5 bbl/day

Salta (Argentina)

Field	Well Number	Depth	Production/Day
Ramos	R-9	3116	25.2 bbl/day

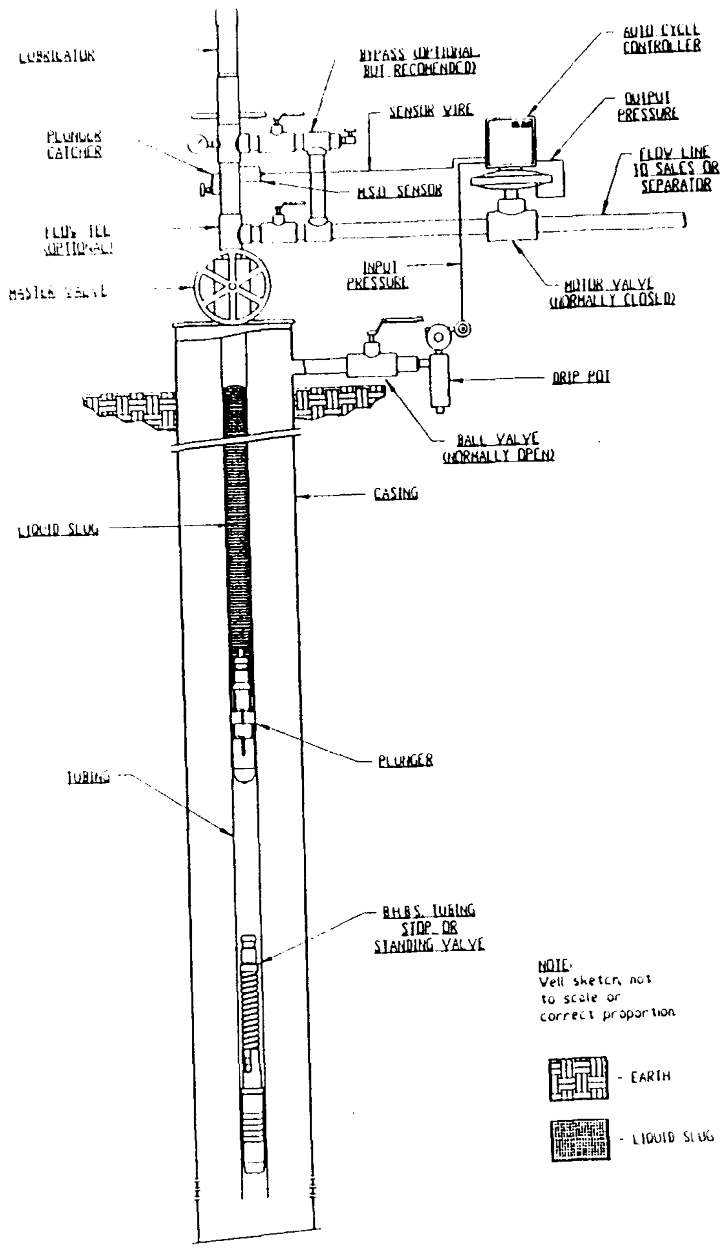

Figure 1 - Typical Plunger Lift System without Injection Gas

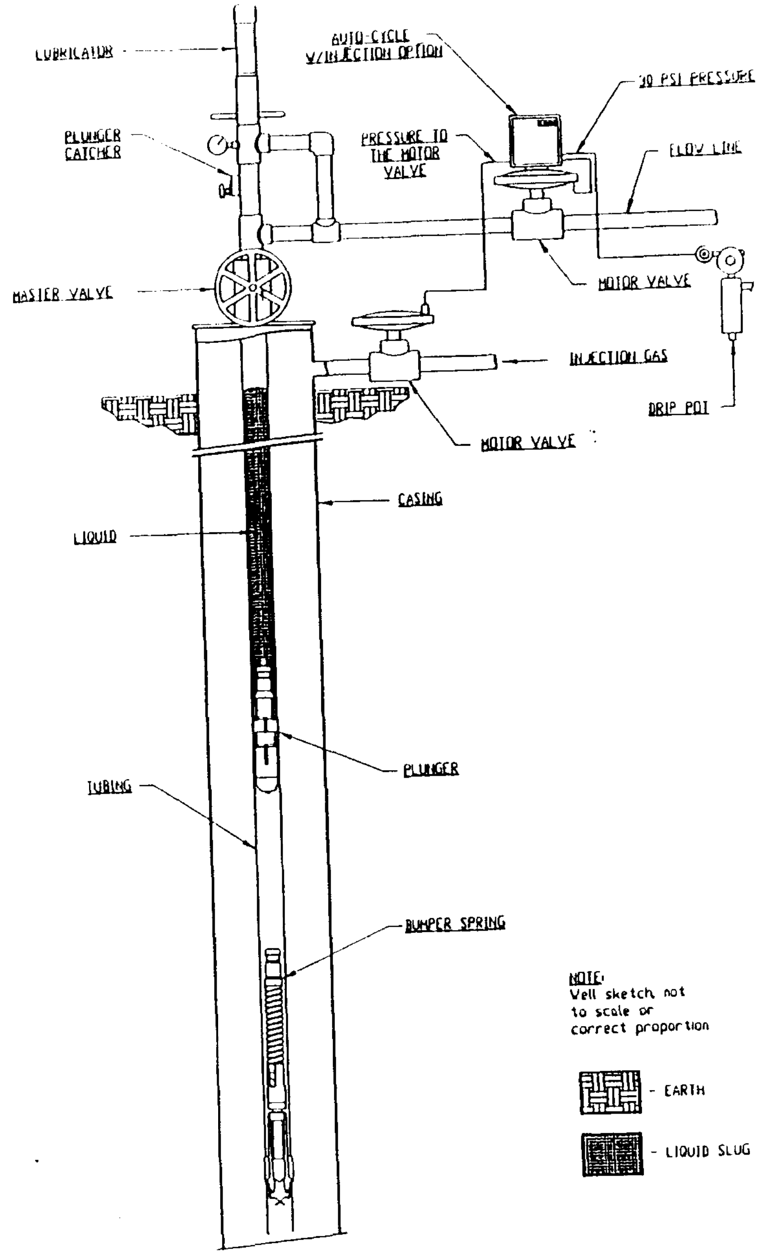

Figure 2 - Typical Plunger Lift System with Injection Gas