PLUNGER LIFT AN ECONOMIC ALTERNATIVE TO SUCKER ROD PUMPS

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ABSTRACT

Due to the economic down turn in the Petroleum Industry over the past several years, Oil & Gas Operators have begun to search for a more cost effective method of Artificial Lift than the Sucker Rod Pump.

This narrative will explain the Plunger Lift System, how it works, and methods for selecting candidates. Included are four (4) case histories, with actual economic evaluations for one year and projected savings over a five (5) year period.

INTRODUCTION

The most economical method of producing an Oil/Gas Well, is to allow the well to produce under its own power (Flowing). As these wells begin to lose bottom hole pressure, they become candidates for one of several types of Artificial Lift, the most common is the Sucker Rod Pump. Many of the wells that have been Rod Pumped for several years begin to experience various types of production difficulties, such as repeated pump failures due to declining fluid production. Related failures can be rod parts, tubing wear, and numerous other downhole problems. In addition surface equipment is subject to many types of failures, as time goes on. A few examples are gear box wear, bearing wear, electric motor or engine failure, and V-belts, not to mention the on going maintenance required just to keep the pump jack in operation, as well as electricity or fuel usage.

The Plunger Lift method of Artificial Lift offers a solution to some of these problems, provided wells can meet the criteria for Plunger Lift. The well must have a relatively High Gas to Liquid Ratio (GLR) and sufficient pressure to lift the plunger and produced fluids to the surface.

PLUNGER LIFT OVERVIEW

The Plunger Lift System is a method of Artificial Lift that utilizes energy from the formation in the form of gas and gas pressure stored in the casing to force a free piston (plunger) to travel up and down the tubing in a cyclic manner.

With the well shut in, the plunger falls to the bottom of the tubing, as pressure builds in the well. The produced fluids are forced past the plunger into the tubing, while drive gas and pressure differential are stored in the casing. When sufficient gas and pressure has been accumulated in the casing to achieve the critical velocity necessary to produce the fluid slug and the Plunger to the surface, the flow line is then automatically opened, allowing the plunger to cycle. The plunger then acts as an Interface between the slug of liquid above it and the gas below it, thus preventing "Fall Back" of the liquids into the well bore.

PLUNGER LIFT CRITERIA

There are two criteria to look for when considering a well for Plunger Lift. First is the Gas/Liquid Ratio, and second is the net operating pressure. Net operating pressure is simply the difference between the well's shut in pressure and the flow line pressure.

It takes approximately 500 cf of gas to lift one (1) barrel of fluid 1,000 ft.. This means that a 6,000-ft. well would require at least 3 Mcf to lift each barrel of fluid to the surface. If we apply this formula to a 6,000-ft. well that produces 20 barrels of fluid per day, 60 Mcfd would be needed. This well would have a 3,000:1 GLR.

The net operating pressure for Plunger Lift wells is determined by use of the Foss & Gaul Curves. These curves are accepted by the Plunger Lift Industry, but are normally found to be somewhat conservative, due to the improved seal efficiency of plungers manufactured in recent years.

Based on the Foss & Gaul Curves, the 6,000-foot well, making 60 Mcfd, and 20 barrels of fluid, would require 320 psi net operating pressure plus flow line pressure. If the flow line pressure is 30 psi, the casing build up would need to be 350 psig. The same well making 120 Mcfd would have a 6,000:1 GLR and would have a net operating pressure of 200 psi. plus 30 psi. line pressure for a total casing build up of 230 psig.

In order to replace a Rod Pump System with a Plunger Lift System it is necessary to go through these same steps. First make sure that the well has approximately 500 cf of gas for each barrel of fluid, per 1,000 ft. of lift. Second, shut the well in, record the tubing and casing pressure build ups at two (2), four (4), and six (6) hour intervals. This pressure data is more accurate and reliable if the well is pumped off when it is shut in. If the net operating pressure meets the requirements (Foss & Gaul Curves) then it is a well that could operate on its energy, without the cost of electricity, pumping unit maintenance and repairs, rod parts, tubing wear, downhole pump failures, stuffing box leaks, and many other related problems, not to mention lost production.

One of the biggest problems associated with Rod Pumping wells that have a high Gas/Liquid Ratio is the phenomenon known as Gas Interference or "Gas Lock" in the downhole pump. This Gas Interference results in lost production, as well as increased Lifting Cost due to additional mechanical failures.

Paraffin is another problem encountered in many high gas/liquid ratio rod pumping wells. Since the plunger makes several trips a day, the tubing is kept clear of paraffin build up, which reduces down time due to paraffin cutting, therefore increasing production.

It is important to note that a certain amount of preparation is necessary when converting a well from Rod Pump to a Plunger Lift System. Downhole equipment such as Packers, Tubing Anchors, Mud Anchors, and Gas Anchors should be removed. The tubing requires pressure testing and should also be broched. If these steps are not taken the plunger may not seal properly, and the efficiency of the Plunger Lift System will be greatly reduced. The Plunger Lift System conversion also requires that a full opening master valve be installed in place of standard Rod Pumping arrangement.

CASE HISTORIES

The wells included in this evaluation are located in Martin County, Texas. They have been produced for a number of years, with 228 Pumping Units and Sucker Rod Pumps. The Plunger Lift Systems were installed late in 1990, and either maintained or in some cases increased production.

The Pumping Unit Equipment that was made available for either salvage or for other Pumping Unit applications has an estimated value of $30,100.00 per well. This adds to the total savings of the Plunger Lift System $120,400.00 . See Graph #6

Over a five year period the savings in lifting costs for this four (4) well program is estimated to be $145,694.00. If the Pumping Unit equipment value is added in, the total is $266,094.00, or $66,523.50 for each well in test. See Graphs #1-5

CONCLUSION

This four well project shows the typical economic advantages that can be expected by replacing Rod Pumping Systems with Plunger Lift Systems.

Wells that qualify for Plunger Lift Systems, can not be operated more economically or efficiently by any other means of Artificial Lift.

The wells in this study are identified as Wells #1, #2, #3, #4

Figure 1 Well Data

Figure 2 Actual cost of Plunger Lift Sys. and related expenses

Figure 3 Actual Rod Pumping expense for one year

Graphs 1-4 Operating expense for Rod Pumping Systems and Plunger Lift Systems based on actual operating expenses.
Note: The Plunger Lift Systems include the cost for equipment, installation, and related expenses.

Graph 5 Cumulative five year estimated operating expense.

Graph 6 Total Savings including salvage value

Attachments - Foss & Gaul Curves

REFERENCE

The American Oil & Gas Reporter March, 1992 Article entitled "Times Demand Economic Artificial Lift" by Charlie McCoy and George Davis.

Foss, D. L. and Gaul, R. B.: "Plunger Lift Performance Criteria with Operating Experience -- Ventura Ave. Field." Drilling and Production Practices, API 1965, pgs. 124-140.

ACKNOWLEDGEMENT

Thanks to Mr. George Davis Production Manager, RK Petroleum for his assistance and cooperation.

	WELL #1	WELL #2	WELL #3	WELL #4
FORMATION	WOLFCAMP	WOLFCAMP	WOLFCAMP	WOLFCAMP
SEAT NIPPLE DEPTH	9050'	9100'	9175'	9200'
DAILY OIL PROD.	8 BOPD	5 BOPD	7 BOPD	4.5 BOPD
DAILY WATER PROD.	2 BWPD	1 BWPD	1 BWPD	.5 BWPD
DAILY FLUID PROD.	10 BPD	6 BPD	8 BPD	5 BPD
DAILY GAS PROD.	95 MCFD	350 MCFD	110 MCFD	170 MCFD
GAS/LIQUID RATIO	9500:1	58,000:1	13,750:1	34,000:1
SALES LINE PSI	30 PSI	30 PSI	30 PSI	30 PSI
NET OPER. PSI *	180 PSI	190 PSI	170 PSI	140 PSI
ACTUAL OPER. PSI	210 PSI	220 PSI	200 PSI	170 PSI
PLUNGER TRIPS/DAY	9	8	11	9

* BASED ON FOSS & GAUL CURVES

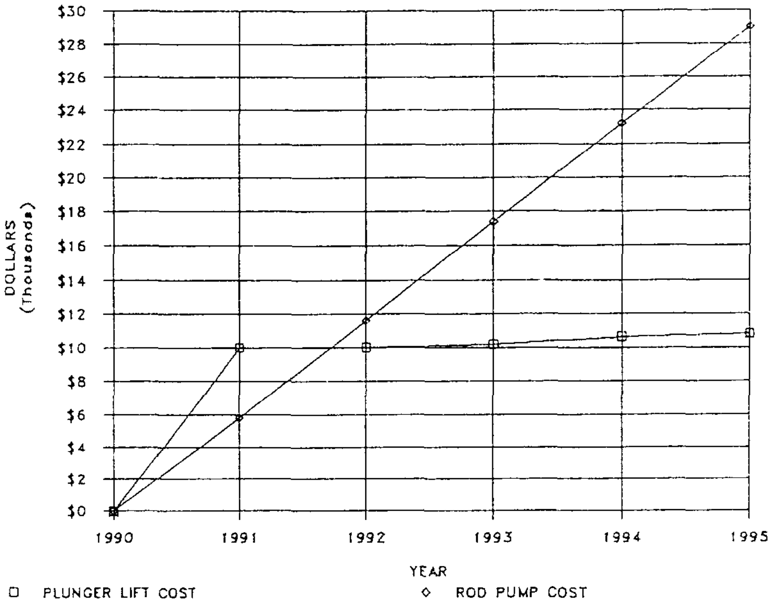
Figure 1 - Test well data

	WELL #1	WELL #2	WELL #3	WELL #4
PLUNGER LIFT EQUIP.	$4,966.00	$5,337.00	$5,055.00	$5,284.00
PULLING UNIT $105/HR	$4,567.00	$1,785.00	$2,625.00	$4,462.00
WIRELINE	$468.00	$730.00	$2,437.00	$1,903.00
TOTAL INSTALLATION	$10,001.00	$7,852.00	$10,117.00	$11,649.00

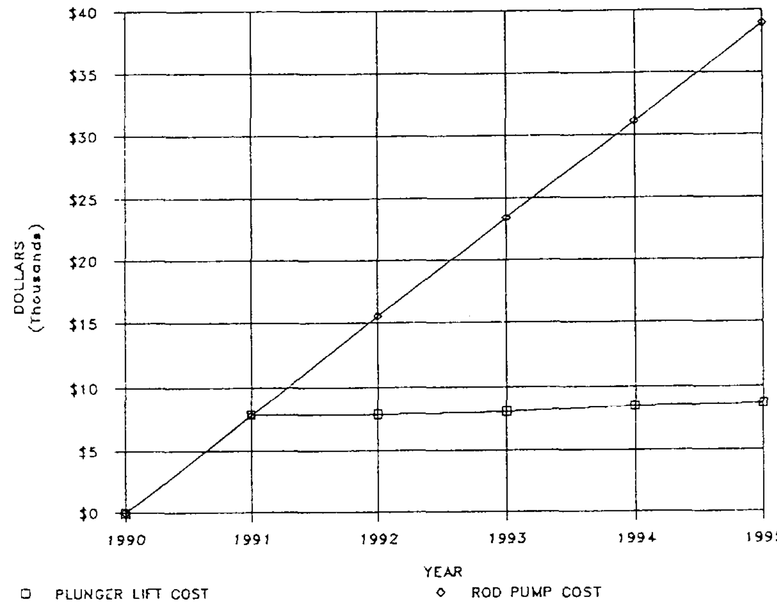
Figure 2 - Plunger lift installation

	WELL #1	WELL #2	WELL #3	WELL #4
DOWN HOLE REPAIR	$2,201.00	$4,187.00	$11,936.00	$5,012.00
HOT OIL	$1,440.00	$1,440.00	$1,440.00	$1,440.00
ELECTRICITY	$2,160.00	$2,160.00	$2,160.00	$2,160.00
TOTAL ANNUAL EXPENSE	$5,801.00	$7,787.00	$15,536.00	$8,612.00

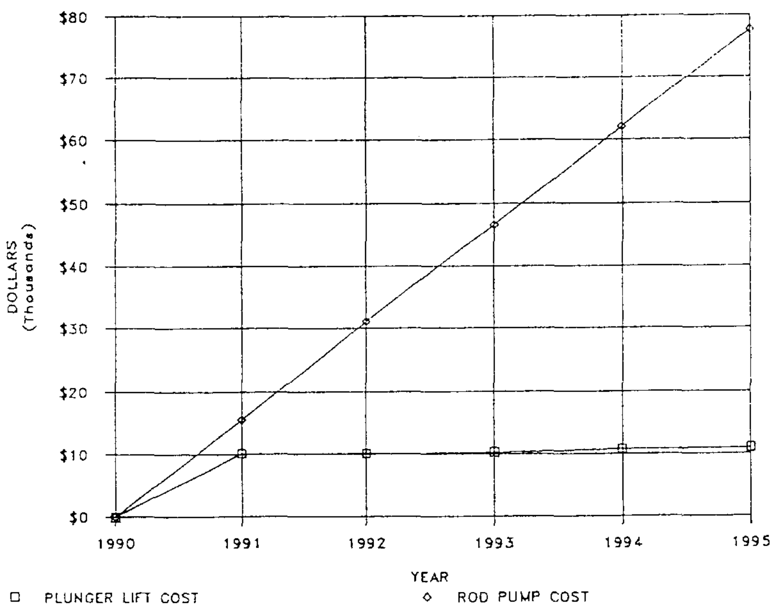
Figure 3 - 1990 annual rod pumping expenses



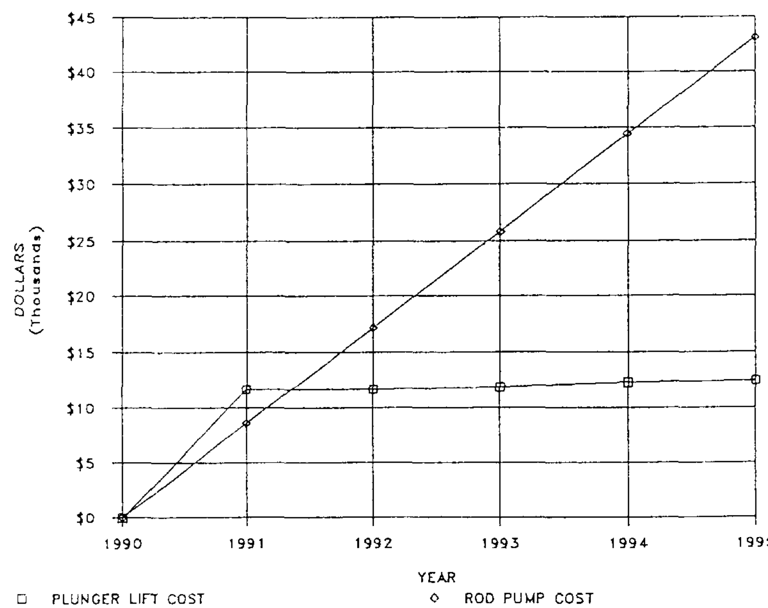
Graph 1 - Plunger lift/rod pump (Test Well #1, Martin County)



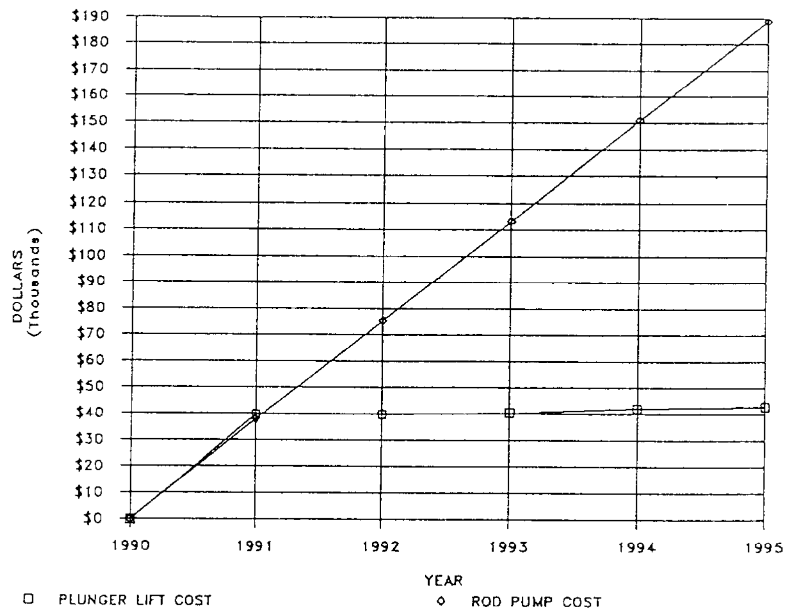
Graph 2 - Plunger lift/rod pump (Test Well #2, Martin County)



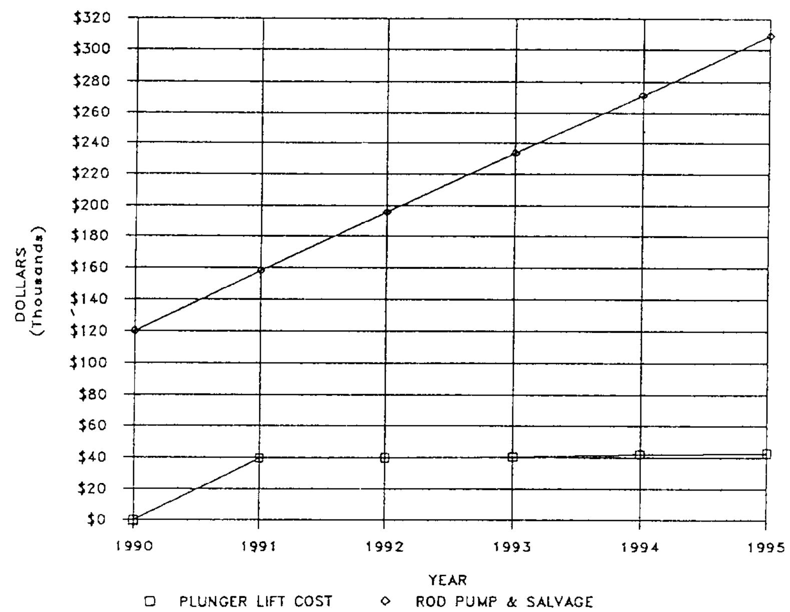
Graph 3 - Plunger lift/rod pump (Test Well #3, Martin County)



Graph 4 - Plunger lift/rod pump (Test Well #4, Martin County)

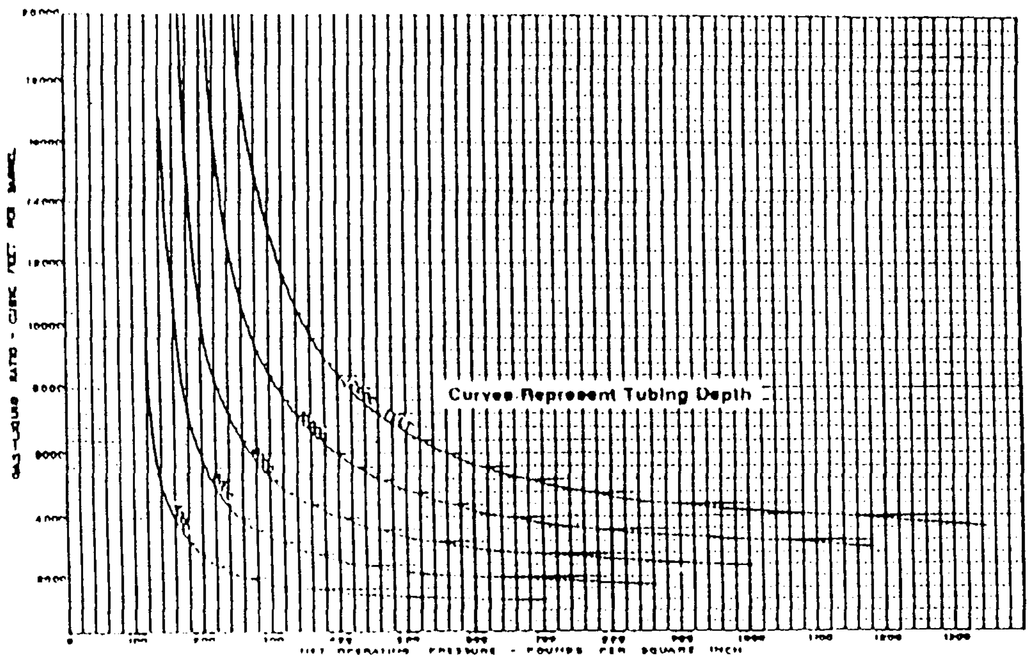


Graph 5 - Cost comparison - plunger lift/rod pump

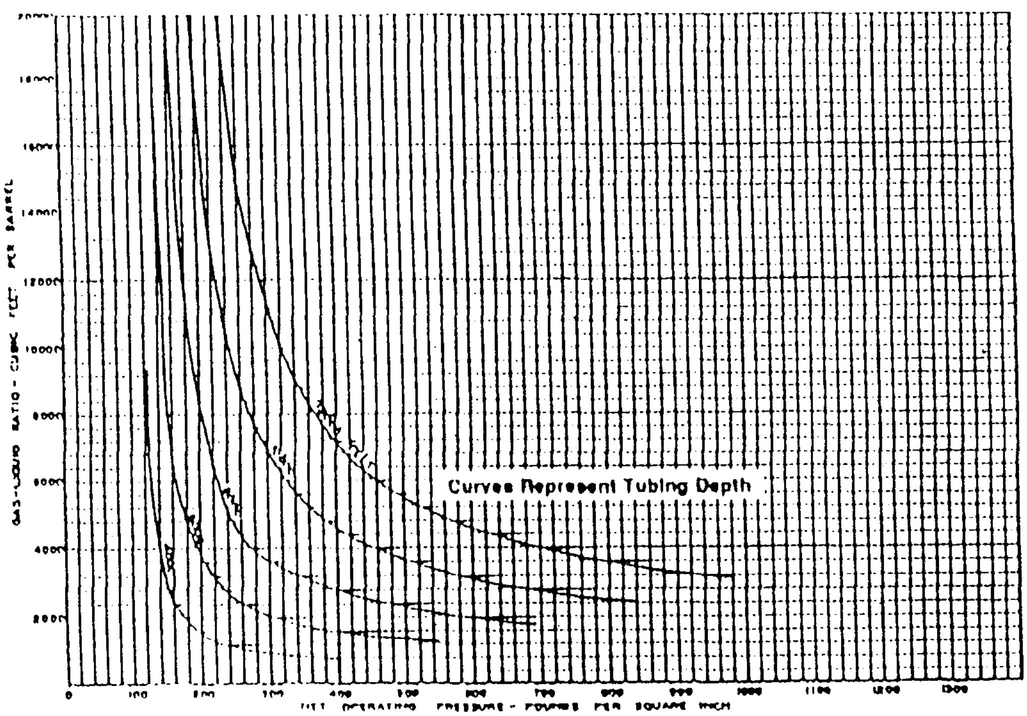


Graph 6 - Total cost and savings comparison - plunger lift/rod pump

Gas and Pressure Requirements — 2-In. Tubing



Gas and Pressure Requirements — 2½-In. Tubing



To use these curves, find the well Gas-Liquid Ratio at the left. Draw a line to the right to the curve that represents tubing depth. Then draw a line down to the Net Operating Pressure Requirement at the bottom of the graph. These curves are provided as a guide to assist in defining the suitability of wells for plunger lift systems.

Foss and Gaul Curves