PROVING THE USE OF PLUNGER LIFT IN WELLS WITH SET PACKERS OR PERMANENT TUBING

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Abstract

This paper will discuss the successful installation of plunger lift systems in wells with set packers or permanent tubing. Several case histories will be presented with a discussion on the resulting production increases, cost of installation and economic information.

Prior to the discussion of the case histories of the plunger lift installations with set packers, the basics of plunger lift systems will be discussed. This discussion will include a description of plunger lift, why a plunger lift might be used, the formula for determining candidates for plunger lift installations and the various types of plunger lift applications.

Introduction

Plunger lift is a method of artificial lift which utilizes energy from a well's own gas to lift accumulated fluids in the wellbore. The plunger acts as a mechanical interface between the gas and liquid in a well, with the gas forcing the plunger up the tubing thus displacing the fluid above it. Plunger lift is successful primarily in high gas-liquid ratio oil wells and gas wells for constant liquid removal.

Low bottom hole pressure from natural depletion normally causes fluid accumulation in the bottom of a well as the flowing velocity slows down. By intermitting pressure buildups and the use of bottom hole tools the load can be delivered to the surface in a slug for a clean wellbore operation. This allows maximum production and more drawdown than natural flow, extending the life of the well.

The components of a plunger lift system are basic, as shown in Figure 1. They consist of a traveling valve (the plunger), a standing valve placed at the end of the tubing, and a bumper spring between the valves to cushion the bottom of the tubing when the plunger falls back to the bottom of the hole. The traveling valve or plunger runs from the bottom of the tubing to the surface. The plunger is then stopped by a lubricator with a spring loaded cap on surface. A motor valve and controller are mounted downstream of the lubricator to open and close the well between flowing cycles.

The various well conditions which are encountered when a plunger lift is installed are somewhat similar, but each individual well's recovery, gas volume and fluid load determine the proper equipment arrangement and technique to be applied. Flexibility to adapt the plunger lift to the well conditions is a very important key to success.

The benefits of installing and using plunger lift are:

1). Fluid removal from the wellbore utilizing the well's own energy,
2). Increased gas sales due to unrestricted flow from perforations to surface from constant fluid removal,
3). Increased oil production due to more drawdown from the formation,
4). Initial installation cost is considerably less than other types of artificial lift,
5). Maintenance cost and equipment replacement cost are minor compared with other forms of artificial lift,
6). Constant paraffin buildup prevention in tubing, and
7). Reduction of paraffin buildup in flow lines and production equipment.

Determination of Plunger Lift Candidates and Well Preparation

To determine whether a well is a legitimate candidate for a plunger lift installation a simple formula can be used. The formula states that a minimum of 500 SCF of gas per barrel of fluid per 1000 ft. of depth is required for a plunger lift to work in any given well. If this requirement is met then the well should have enough gas production and reservoir energy to lift the plunger and the accumulated fluids in the bottom of the well. The preparation of the well required prior to installing a plunger lift depends on the technique to be used in the well. In all wells that are to have plungers installed, the tubing should be broached and tested. A full opening master valve should be installed on the well head if one is not already present.

Types of Plunger Lift Installations

As mentioned earlier, a well's recovery, gas volume and fluid load determine the proper equipment arrangement and plunger lift technique to be used. Listed below are the plunger lift techniques used today:

1. Conventional Time Controller: In this technique the casing or annulus is used to store gas during the shutin period. The shutin period is set by time. When the well is opened at the surface the stored gas goes up the tubing in turn driving the plunger up the tubing and delivering the gas production to a low pressure sales system. See Figure 2.

2. Time or Pressure Auto Adjust Controller: This technique is similar to the Conventional Time Controller technique with the exception that the shutin periods can be adjusted by monitoring the pressure instead of time. See Figure 3.

3. Time Controller Shut In on Arrival Technique I: In this technique the casing and tubing are communicated together. The tubing goes to a low pressure vent or tank while the casing is regulated with a back pressure

valve to a high pressure sales line. In this technique there are two flow lines. This technique may be used with a compressor. See Figures 4a and 4b.

4. Time Controller Shut In on Arrival Technique II: This technique is similar to the number 3 technique listed above with the exception that the casing is open to a high pressure sales line continuously. See Figure 5

5. Time Only Auto Adjust Controller Technique I: In this technique there is no casing gas drive to move the plunger because there is a set packer or permanent tubing in the well. The tubing goes to a low pressure sales line. See Figure 6.

6. Time Only Auto Adjust Controller Technique II: This technique is similar to the number 5 technique listed above with the exception that in the early flow period the gas from the tubing goes to a high pressure sales line. Then when the produced fluid gets to surface it goes to a low pressure tank until the plunger arrives at the surface. After the plunger arrives at the surface the line to the low pressure tank is shut off and the well is in afterflow to the high pressure sales line again. See Figure 7.

As can be seen from above there are several different techniques in which to install plunger lifts in any given well. Some of these techniques are used more commonly than others. Until just recently the techniques used for wells with set packers or permanent tubing (techniques 5 and 6 above) were very uncommon if not non-existent. This paper will now discuss the successful installation and use of plunger lift in wells with set packers or permanent tubing.

Case Histories: Using Plunger Lifts in Wells with Set Packers

Many wells have been abandoned and lost due to casing leaks, collapsed casing and stuck tubing. Producing a well up the tubing only is difficult without the use of the casing annulus in any type of artificial lift. Previously, it had been thought that a plunger lift would not operate in a well with no casing gas drive. Many failures had occurred attempting to operate a plunger lift in this manner because there was no way of monitoring the well inflow and drawdown at the surface.

Today there is a new device which allows monitoring of down hole activity. This device continuously monitors the plunger speed from the bottom of the hole to the surface. As the plunger speed changes the inflow and drawdown change due to fluid load on the plunger or gas volume changes. This monitoring device is called the Auto-Adjust Electronic Controller. A sensor is placed on the lubricator at the surface to detect plunger arrival, thereby determining the speed of the plunger from the instant the well is opened until it arrives at the surface. This speed is recorded in the controller. The controller may then re-adjust the cycle time according to changes in plunger speed.

With this type of plunger lift technique, wells with set packers can be successfully produced without the packer being released. This not only saves rig time and swabbing time, but also eliminates the possibility of contaminating the formation by dumping packer fluid on it. Many gas wells do not recover after being produced several years and then being exposed to contaminating fluids. By leaving the well in its natural flowing state and not disturbing it, the formation is much more receptive to continuous unloading and natural flow. Many plunger cycles extend out to periods of long flow after the plunger has cleared the tubing of fluid. Through monitoring of plunger speed due to load or downstream back pressure changes, the cycle is continuously adapted to the current conditions. This procedure has allowed many successful plunger installations even under adverse conditions.

Case histories in which Time Only Auto-Adjust Controller Plunger Lift Systems were installed in wells with set packers or permanent tubing are presented in Table 1 and Figures 8 - 15. The wells presented as case histories are operated by OXY USA Inc. in Jack and Wise Counties, Texas. Upon success of the first plunger lift installation, a study was performed on all wells operated by OXY USA Inc.in this area. The study looked at the present producing rates, the cumulative production, the current producing equipment, the previous producing equipment, and swab test results on each well. From this study it was concluded that wells with low present producing rates, low cumulative production and wells that never had pumping equipment installed on them were the best candidates for the installation of plunger lift. Twenty four wells were found that met these requirements. To date OXY USA Inc. has installed eight plunger lift systems in this area. Table 1 provides information on the eight wells before and after installation of the systems. The attached production curves (Figures 8 - 15) also show the response of the wells after the systems were installed.

Conclusion

The use of plunger lift in wells with high GORs has been under way for sometime. Just recently has the use of plunger lift in wells with set packers or permanent tubing been used. The case histories presented in this paper have shown that plunger lift in wells with set packers or permanent tubing is a viable means of artificial lift. Not only is it a viable means of artificial lift but in most cases will extend the life of a well that is at its economic limit prior to producing with a plunger lift. If a high GOR well with a set packer in the hole nears its economic limit and plans are to plug the well then the well should be studied and considered for the installation of a plunger lift with a Time Only Auto-Adjust Controller to prolong the life of the well.

Reference

Oil and Gas Well Production - Plunger Lift Methods. Copyright, Gerald K. Boyd, 1977.

The Technology of Artificial Lift Methods, Volume 2b. Kermit E. Brown. Plunger Lift Section by Bolling A. Abercrombie, pages 483 to 506.

Acknowledgements

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Table 1
Case Histories of Plunger Lift Installations in Wells with Set Packers or Permanent Tubing

Information	Well #1 Technique 5 Figure 8	Well #2 Technique 5 Figure 9	Well #3 Technique 5 Figure 10	Well #4* Technique 6 Figure 11	Well #5 Technique 5 Figure 12	Well #6 Technique 5 Figure 13	Well #7 Technique 5 Figure 14	Well #8 Technique 5 Figure 15
Formation	Caddo Conglomerate	Bend Conglomerate	Caddo Conglomerate	Atoka 5800	Bend Conglomerate	Bend Conglomerate	Bend Conglomerate	Caddo Conglomerate
Depth	5437'	6019'	5537'	5690'	5737'	5591'	4773'	5471'
Installation Cost	$7300	$6900	$6800	$7200	$7500	$6700	$7000	$7300
Production Prior to Installation	0 BCPD 0 BWPD 13 MCFGPD	4 BCPD 1.5 BWPD 164 MCFGPD	0 BCPD 0 BWPD 110 MCFGPD	0 BCPD 0 BWPD 35 MCFGPD	0 BCPD 0 BWPD 130 MCFGPD	0.5 BCPD 0 BWPD 180 MCFGPD	0 BCPD 0 BWPD 100 MCFGPD	0 BCPD 3 BWPD 20 MCFGPD
Production After Installation	1 BCPD 0.5 BWPD 140 MCFGPD	4.5 BCPD 1 BWPD 238 MCFGPD	1 BCPD 0.5 BWPD 264 MCFGPD	0.5 BCPD 0.5 BWPD 142 MCFGPD	0.5 BCPD 1.5 BWPD 380 MCFGPD	1.5 BCPD 1 BWPD 490 MCFGPD	0 BCPD 1 BWPD 223 MCFGPD	3 BCPD 3 BWPD 227 MCFGPD
Production Increase	1 BCPD 0.5 BWPD 127 MCFGPD	0.5 BCPD 0.5 BWPD 74 MCFGPD	1 BCPD 0.5 BWPD 164 MCFGPD	0.5 BCPD 0.5 BWPD 107 MCFGPD	0.5 BCPD 1.5 BWPD 250 MCFGPD	1 BCPD 1 BWPD 310 MCFGPD	0 BCPD 1 BWPD 123 MCFGPD	3 BCPD 0 BWPD 207 MCFGPD
Payout Period	3 Weeks	5 Weeks	4 Weeks	6 Weeks	3 Weeks	2 Weeks	5 Weeks	4 Weeks

*: Well #4 has permanent tubing. All other wells have set packers.

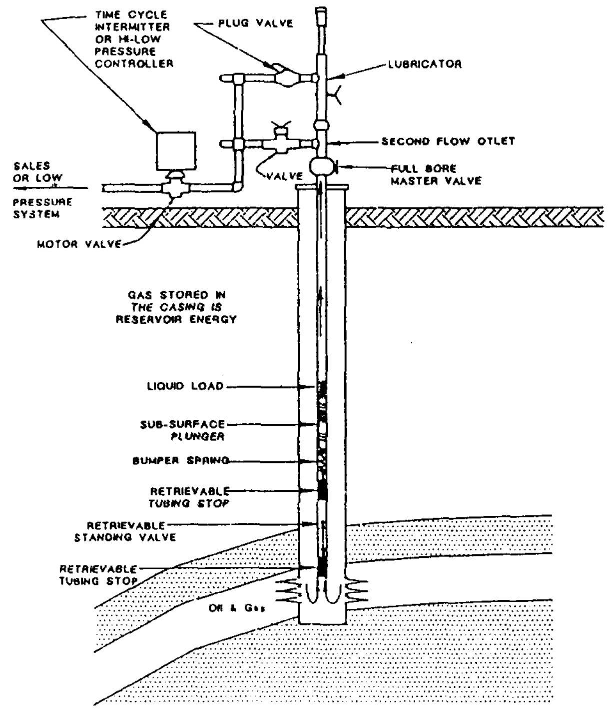


Figure 1 - Components of a typical plunger lift system

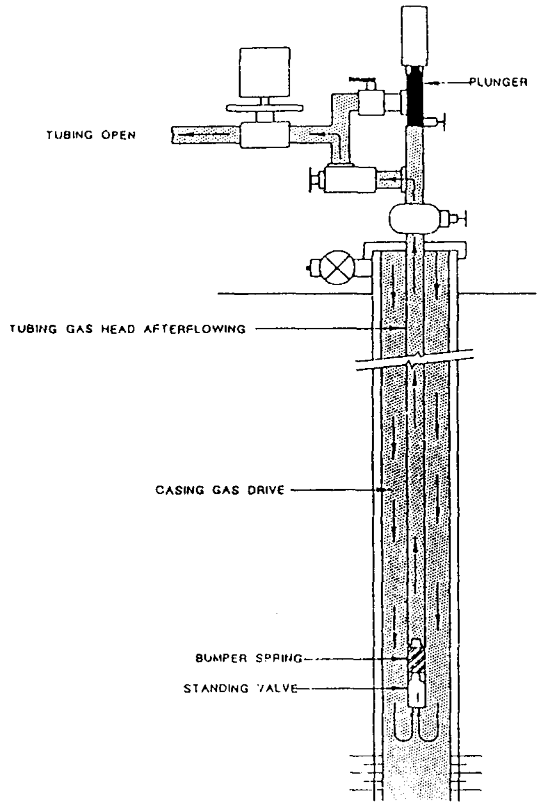


Figure 2 - Conventional time controller

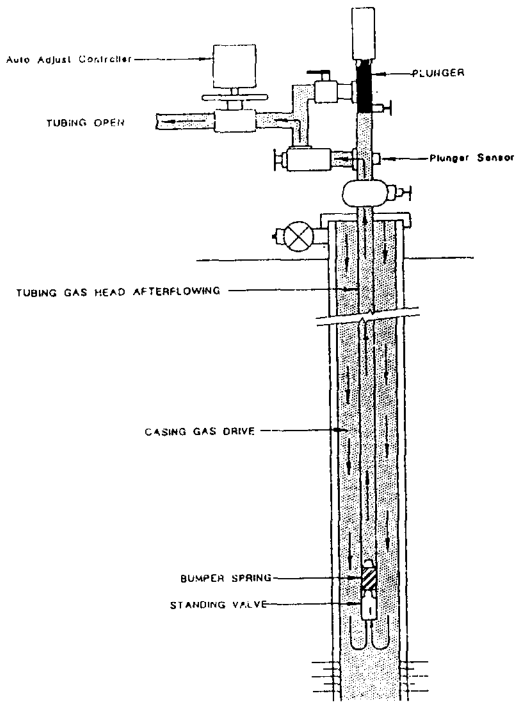


Figure 3 - Time or pressure auto adjust controller

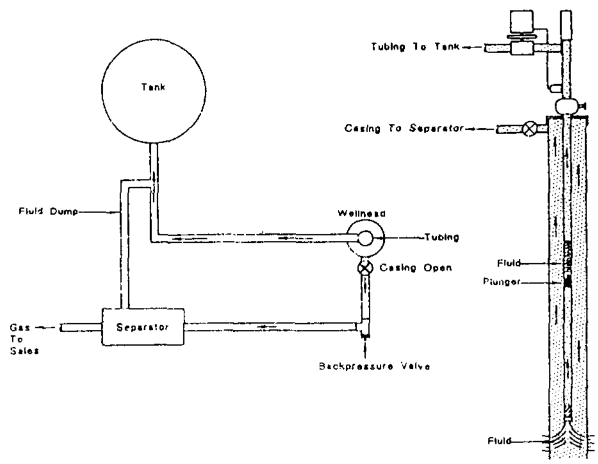


Figure 4a - Time controller shut in on arrival technique I without compressor

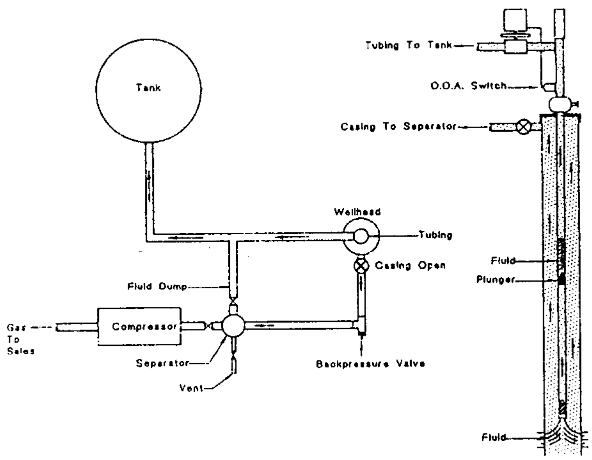


Figure 4b - Time controller shut in on arrival technique I with compressor

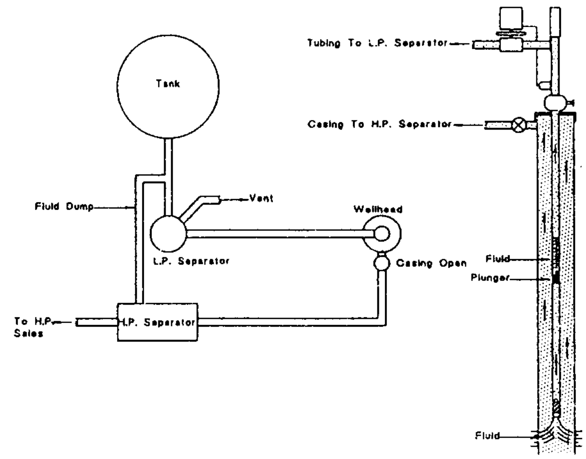


Figure 5 - Time controller shut in on arrival technique II

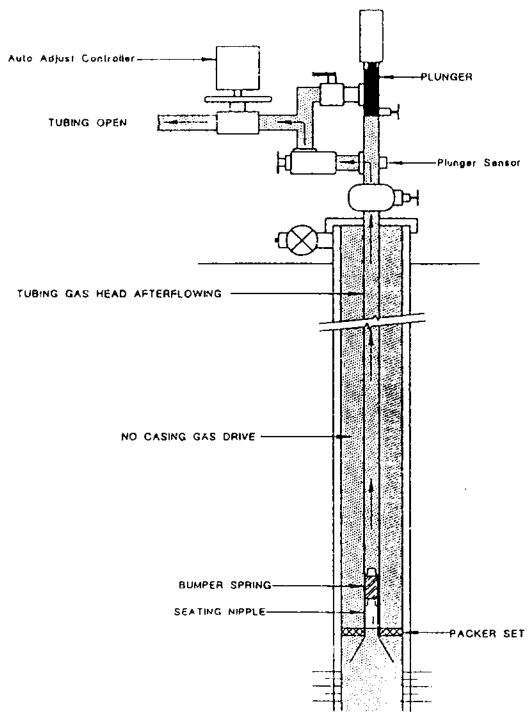


Figure 6 - Time only auto adjust controller technique I

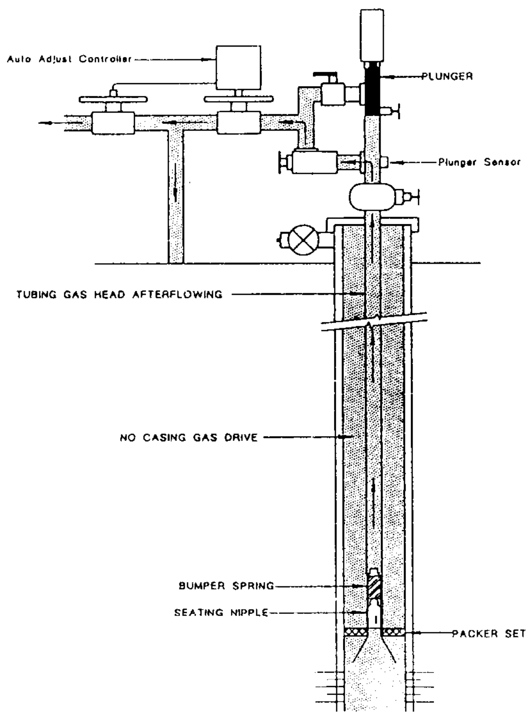
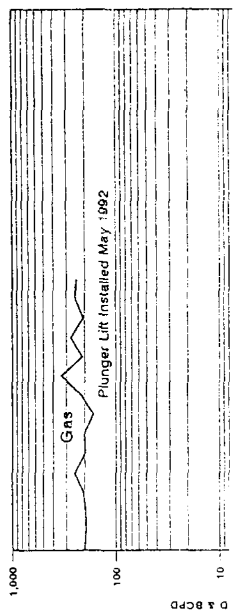
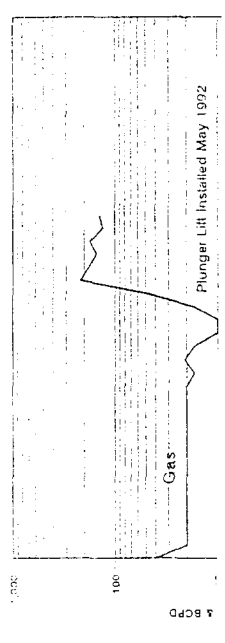


Figure 7 - Time only auto adjust controller technique II





ELECTRICAL LOAD SHEDDING PROGRAM AT THE SALT CREEK FIELD UNIT

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ABSTRACT

This paper discusses a recently implemented electrical load sheddin Salt Creek Field Unit (SCFU) in Kent County, Texas. The proje interruption of SCFU electrical load during the wholesale utilit load. By interrupting SCFU load during the utility's monthly electrical demand charge is reduced by $7.16 or $6.03 per inter depending on the time of year.

A dual demand electrical rate schedule makes the load shedding c With this rate schedule, the demand charge is divided into two demand charge is based on the highest SCFU electrical load during th while the other is based on the SCFU load during the wholesale u peak. The goal of the load shedding program is to interrupt SCFU el the time of the utility's peak load thereby reducing one componen charge.

A critical element to the load shedding program is the ability to wholesale utility's monthly peak load will occur. The utility's highly dependent on the temperature in the utility's main load located in and around Stephenville, Texas. By closely monitoring th and temperature/weather data in Stephenville, the time of the uti can be forecasted. Historical load and temperature/weather info utilized in peak load forecasting.

Another key element is the selection of SCFU electrical load to during the utility's monthly peak. Currently, high pressure inj artificial lift installations are interrupted for load shedding pur interruption of artificial lift installations results in deferred p must be carefully prioritized for interruption so that lost reven Also, limiting total interruption time and frequency during each b very important in minimizing lost revenue and cycling of lift equip of load shedding each artificial lift installation is determine potential lost revenue from potential electrical savings.

This paper addresses the electrical rate schedule design, wholes forecasting, load shedding methodology, and results of the program

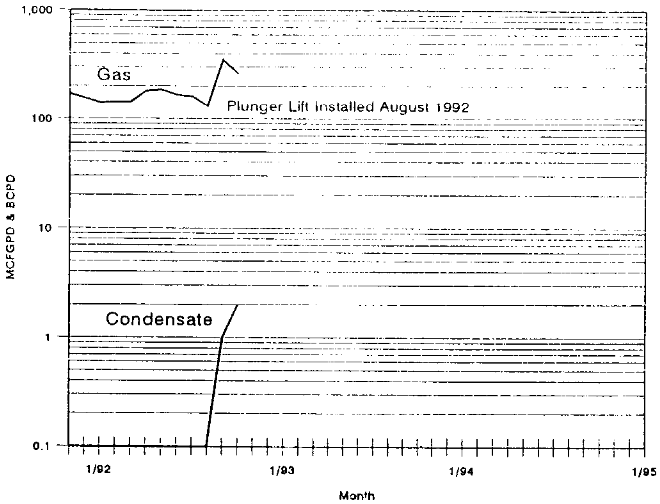

Figure 12 - Well No. 5 technique 5 with set packer

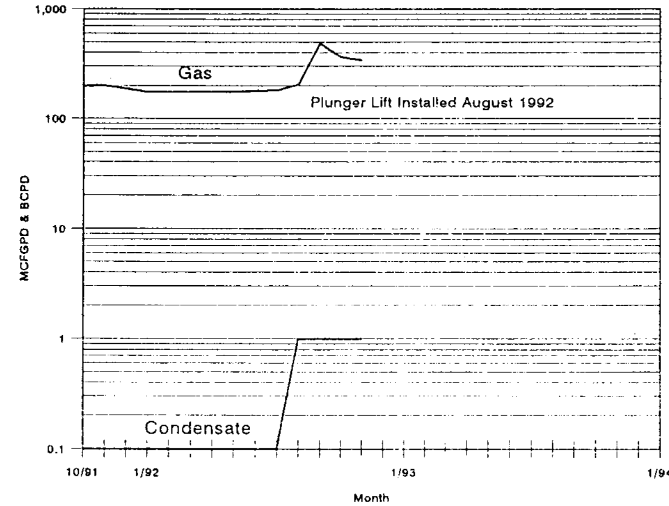

Figure 13 - Well No. 6 technique 5 with set packer

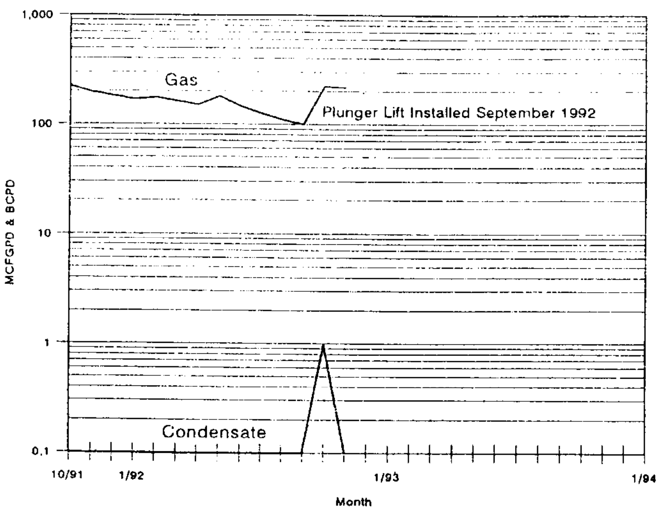

Figure 14 - Well No. 7 technique 5 with set packer

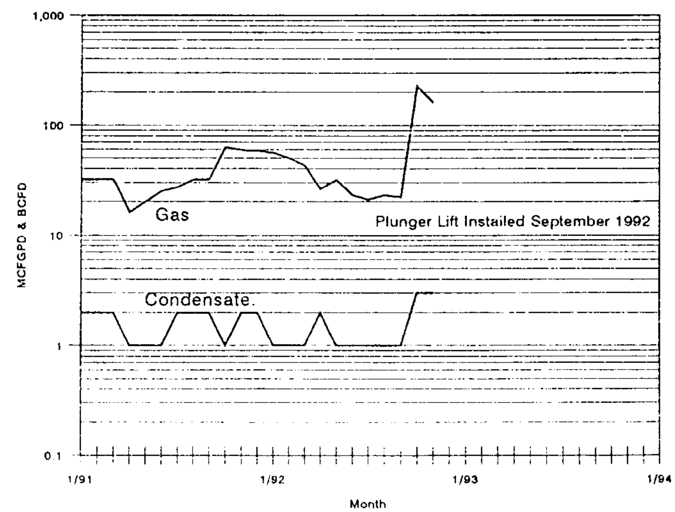

Figure 15 - Well No. 8 technique 5 with set packer