PLUNGER LIFT BENEFITS BOTTOM LINE FOR A SOUTHEAST NEW MEXICO OPERATOR

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Abstract
The development of the Eumont gas play in Lea County, New Mexico created unacceptably high operating costs associated with gas well production. Two major issues were economically producing low pressure gas wells (1.5-2 psi/100 feet) with low connate water production and proppant production. The first choice for artificial lift once loadup occurred was beam pumps. Sand production and low fluid volumes however forced a paradigm shift to evaluate plunger lift as an alternative based on the low fluid volumes and low bottom hole pressures. The end result has reduced operating costs by over 70% in the areas that plunger lift has become the primary artificial lift method and reduced the lease expense per BOE by 25% over the 2-1/2 year implementation period.

This paper discusses the steps taken to apply basic plunger lift concepts and progresses to the current plunger lift system that incorporates annular flow to minimize bottom hole pressure; therefore maximizing production. Evidence will be presented to validate that switching from beam pump to plunger lift has on average increased production. integrating this "new found" technology on high GLR oil wells has been beneficial as well.

Introduction
A development program to access gas reserves in the Eumont Pool began in 1993 and continued through 1997 increasing gas production by 17.5 MMCFPD (Fig. 1). The producing horizons that comprise the Eumont Pool include the Yates, 7-Rivers, and Queen with a depth interval of 2900-3600 feet. The lithology in the productive stringers is dense dolomite and anhydrite with interbedded permeable siltstone and sandstone'. Permeability is in the range of 0.01 to 10 millidarcies and porosity is in the 6-20% range. The completions normally encompass 300–800 feet, perforating the stringers within the gross interval. The stringers are usually sand fracture stimulated for economic recoveries. Proppant production has historically been an issue in these shallow gas completions. The proppant production is a result of inadequate proppant packing near the wellbore in each of the fracture stimulated stringers. A great deal of time has been spent on sand fracture stimulation optimization, but is beyond the scope of this paper.

As production rates dropped into the liquid loadup range' artificial lift became necessary. A few attempts at velocity strings were made, but due to the low bottom hole pressures, the increased frictional pressure drop associated with the smaller internal diameter reduced the applicability of this method. For this reason, rod pumps were installed in the candidate wells. Sand influx necessitated multiple well servicing repairs to the rod pump and sand cleanouts. in an effort to reduce sand influx, the end of tubing was raised to the top third or above the perforated interval causing increased backpressure on the producing interval reducing sand influx. The increased backpressure also reduced production volumes.

In late 1996, plunger lift was installed on a well with frequent failures to reduce lifting costs. Success was noticed early on by applying the basic plunger lift techniques[3,4,7]. Production optimization and cost reduction success was immediate. Production was increased back to the wells normal decline and the subsequent operating costs were reduced (Fig. 2). As rod pumped wells failed, plunger lift systems have been installed, reducing the operating costs by 70% while maintaining or increasing gas production rates (fig. *3).*

In an effort to further optimize gas production the operating casing pressure for plunger lift operations has been reduced by producing the casing during the afterflow time and shutting in before the "off' time in order to transfer accumulated fluids in the annulus to the tubing. This was achieved by integrating the "flowrate controller" concept presented by Elmer, W.G.[5] into plunger lift operations. Candidate wells for annular flow were selceted using the pseudo-steady-state flow equation.

Plunger Lift basics
Plunger lift was somewhat new to operations requiring some training to provide any chance of success. An introduction to plunger lift was necessary to insure an effective plunger lift program.

Many technical papers have been written on plunger lift to provide equations to model the dynamics of plunger lift. Baruzzi and Alhanati [6] have summarized a number of papers devoted to defining theories on plunger lift dynamics. This information didn't provide the basic operational understanding necessary for a successful campaign. A series of papers written by Listiak, S. and Phillips, D.[7] along with other works[3,4] provided the necessary information to properly train operators in basic plunger lift operations. Plunger lift systems optimization is difficult without understanding the following concepts:

1) Inflow Performance Relationships (IPR)
2) Plunger lift operations
3) Unloading curves
4) Plunger efficiency
5) Plunger system maintenance
6) Data Management

Maximizing inflow performance is the key to optimizing production, ie. lowering the bottom hole flowing pressure. This objective contradicts plunger lift operations because shutting in the well is a necessary cycle of the plunger lift system. The "off' time cycle allows enough energy to be stored in the casing annulus to lift the plunger and the accumulated liquids above it. Minimizing the "off' time is desireable for gas production optimization. Some ''rules of thumb" **for** selecting plunger lift candidates have been in the industry for quite some time; 400 scf/bbl/1000' and 1.5 times sales line pressure. Using these guidelines is a good first step in evaluating a possible candidate. The Southeast New Mexico wells met both of these criteria, since the average GLR is 33,000 scf/bbl/1000' and the sales line pressure to casing shut-in pressure ratio ranges from 1.7-3.0.

A typical plunger lift cycle is 1) "off' time, 2) "on" time, and 3) afterflow or sales time. These cycles and their relative importance to the total cycle must be understood by the operator to successfully optimize a plunger lift system (fig. **4).** Another key component is the plunger itself. The advantages of various plunger types are explained well in the literature[4,7]. Tracking the performance of various plungers can help determine the best plunger application **for** a specific well either due to fluid content, tubing condition, solids, or GLR.

Managing the information available on today's microprocessor controllers can simplify troubleshooting and provide a picture of how plunger lift system changes effect production optimization. Periodically recording gas flowrate, tubing, casing, and sales line pressures, number of plunger arrivals, etc. can simplify troubleshooting. Listiak **S.** and Phillips D.[7] provide a flowchart that can help troubleshoot a plunger system (fig. *5).* Scada and other telemetry systems integrated into microprocessor controllers can allow the operator or engineer to make microprocessor controller changes from their offices.

Annular Flow Concept

There were two pieces of information that lead to the annular flow concept. In **1994** operators realized that they could get significant short term production gains when flowing the casing on high rate gas wells, but the benefits would soon die away due to loadup since the tubing/casing annulus equivalent diameter would put the well in the loadup region (Fig. 6). A device called a Tubing Flowrate Controller[5] was assembled using typical oilfield equipment *to* try and take advantage of this excess stored energy. The "Tubing Flowrate Controller" maintained enough tubing flowrate to unload the well and flow any remaining reservoir energy up the casing-tubing annulus. Adding annular flow resulted in an average 60% gas production increase based on the information presented.

The second piece of information was determined while swabbing on loaded up plunger lift wells with the casing closed. This action usually resulted in minimal fluid recovery. When the casing was opened into the flowline, fluids were recovered when swabbing. This event is just a result of lowering the bottom hole pressure allowing accumulated fluid near the wellbore to enter into the wellbore.

These two pieces of information along with the beam pump failures mentioned earlier resulted in the plunger lift installations, but higher casing pressures still remained on wells at or just above their particular unloading rate. During the afterflow cycle, casing pressure is a good indication of the flowing bottom hole pressure and the difference between tubing and casing pressure indicates tubing friction. In these Eumont wells the casing pressure is about 53-83 psia with a flowing tubing pressure of 28-38 psia. The 25-45 psia difference is the additional delta P_{wf} that we wanted to capitalize on. The backpressure equation was used to evaluate the potential upside from lowering the casing pressure.

$$q_{sc} = C(\bar{P}_R^2 - P_{wf}^2)^n \text{ ....(1)}$$

Also known as the gas Inflow performance relationship (IPR)[8]. The exponent n ranges from 0.5-1.0. Simplifying the IPR equation further by assuming $n = 1.0$, a rough estimate of gas production increases can be projected by reducing the P_{wf}. Using a 5-7 day casing/tubing shut-in pressure for P_R and the casing pressure during afterflow for P_{wf} will allow calculation of the flow coefficient, C. An IPR curve can then be constructed and estimates of production increases evaluated by reducing P_{wf} (fig. 7).

Applying the "Tubing Flowrate Controller" theory with plunger lift resulted in the wellhead configuration in fig. 8. A typical plunger lift system with annular flow is 1) "off' time (tubing/casing), 2) "on" time (tubing), 3) afterflow (tubing), 4) casing delay, 5) afterflow (casing), 6) casing purge. Step 4 allows trailing fluids behind the plunger to be unloaded; therefore resulting in consistent plunger arrivals. Step 6 transfers the fluid accumulated in the backside during annular flow to the tubing prior to the "off' time cycle. Through trial and error, casing delay and casing purge were determined to optimize each gas well candidate.

Results

Wells converted to plunger lift either from beam pump or as the first artificial lift installation has resulted in an 85% initial gas production increase and production has stayed above the previous gas production rate for an average 13.7 months. Production curves are provided for nine of the thirty wells converted to plunger lift since 12/96 (Fig.'s 3 & 10). The wells do return to the normal Eumont decline (Fig.1) once reaching pseudo-steady-state flow. The J-2 #16 well whose production plot is shown in Figure *3* had a microprocessor controller malfunction in December, 1999 preventing the casing valve from opening and reverting the well to a typical plunger lift tubing flow system. The tubing gas production rate matches the estimated tubing pre-annular flowrate as was estimated using the backpressure equation. Figure 9 is a plot of the electronically submitted daily production report indicating the production drop.

Some of the wells while on rod pump had been moved into the top third of the productive interval to stay 100–150 feet above the determined sand fill depth. Because the perforated interval is over such a large gross interval, it was not practical to set the end of tubing at the top of the perforated interval. With a 300–800 feet pay interval and a 100-150 psia bottom hole pressure, gas production would be severely limited due to hydrostatics. Plunger lift has allowed the end of tubing to be lowered within a few feet of the historical sand fill depth, extending the time between cleanouts. After sand influx diminishes, the end of tubing is lowered to the lowest point possible. The end of tubing set point has been determined by reviewing the contribution of the lowest set of productive stringers, which ends up being in the bottom 5-10% of the perforated interval (fig. 11).

Lease expenses (LE) were evaluated for half **(8) of** the leases that have had plunger lift installations over the last 2-1/2 years to determine the long-term benefits of plunger lift conversion. Gross Lease Operating Income Statements (GLOIS) were used to evaluate the surface maintenance, artificial lift, and subsurface expenses. These eight leases evaluated have *60%* of the thirty plunger lift wells. The eighteen wells on plunger lift comprise 53% of the wells on these eight leases. The other 47% are on rod pump or are still flowing. Without breaking the expenses out to those directly associated with plunger lift the combined selected lease expenses have been reduced by 70%. This reduction is a result of installing plunger lift, reducing or eliminating well servicing, and the associated subsurface costs; ie. Rods, pump replacement, and wellbore cleanouts. The percent reduction would have been greater, but 70% of the plunger lift installations were producing above the unloading rate prior to plunger lift installation. The installation of any artificial lift system will increase operating costs when compared to natural flow. The other component captured was the surface equipment, ie. plunger lift system (fig. 9) and the plunger replacements/repairs. Considering all GLOIS expenses, the LE/BOE was reduced by 25% on these eight leases, $1.80 to $1.35.

Five oil wells with GLR's ranging from 8,000 – 30,000 scf/bbl have had the annular flow plunger lift system installed with only three of the five operating successfully. The selected oil wells are producing downhole commingled Blinebry/Tubb/Drinkard production in Southeast New Mexico. The 500-700 feet of gross pay has been block perforated and hydraulically fractured. For the well types discussed a rule of thumb 1,800 scf/bbl/1000' is necessary for success (Fig. 12). Our experience has shown that a lower GLR/1000' is a beam pump candidate versus plunger lift.

Observations

1. End of tubing location can be the difference between success and failure for a plunger lift system.
2. Standing valves in lower bottom hole pressure wells kept fluids trapped in the tubing, increasing system efficiency.
3. Incremental production increases of 20 MCFPD are sufficient to pay for a plunger lift system.
4. 2-7/8" versus 2-3/8" tubing allows better plunger lift operations requiring less casing-tubing differential for liquid removal.
5. Plunger lift is now the first artificial lift method considered for connate water producing gas wells and high GLR oil wells that meet the 1,800 scf/bbl/1000' criteria.

Conclusions

1. Proper training on plunger lift systems is a vital element for a successful plunger lift program.
2. Generating IPR curves can provide an estimate of potential uplift from converting typical plunger lift wells to annular plunger lift.
3. Lease operating costs can be dramatically impacted when plunger lift systems are installed and properly maintained.

Nomenclature

q_{sc} = Mscfpd
C = flow coefficient
P_R = Reservoir Pressure
P_{wf} = Flowing bottomhole pressure
n = exponent

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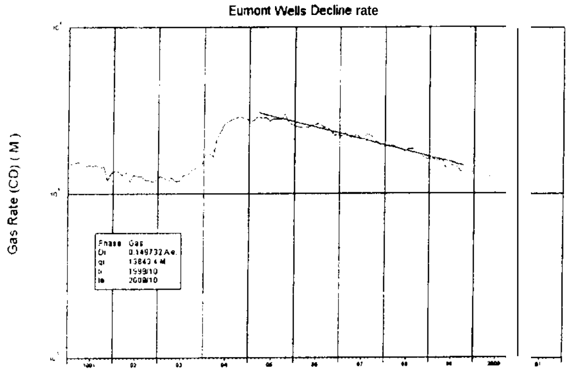

Figure 1 - Eumont Development Program Results with Corresponding Decline

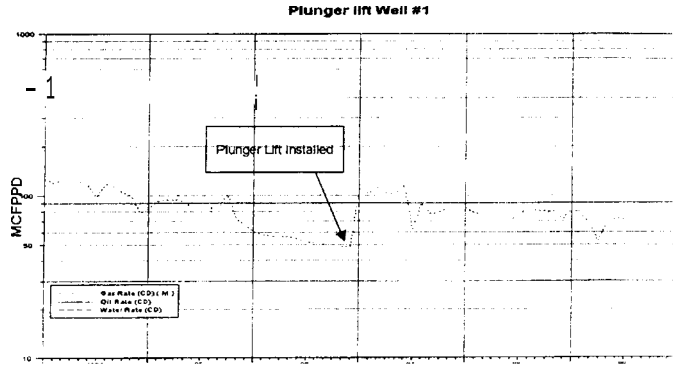

Figure 2 - First Plunger Lift Installation Was on gas engine driven beam pumping unit.

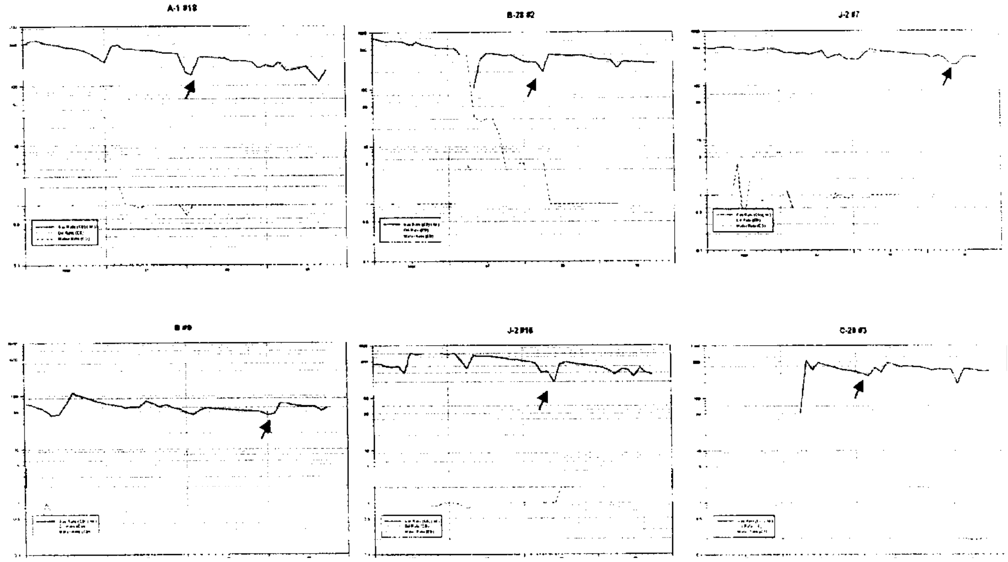

Figure 3 - Rod Pumped Wells Converted to Plunger Lift 12-96 to 6-99
The arrow indicates the date plunger lift was installed after a rod pump failure. All wells are flowing with casing flow. Units are monthly average MCFPD vs. time.

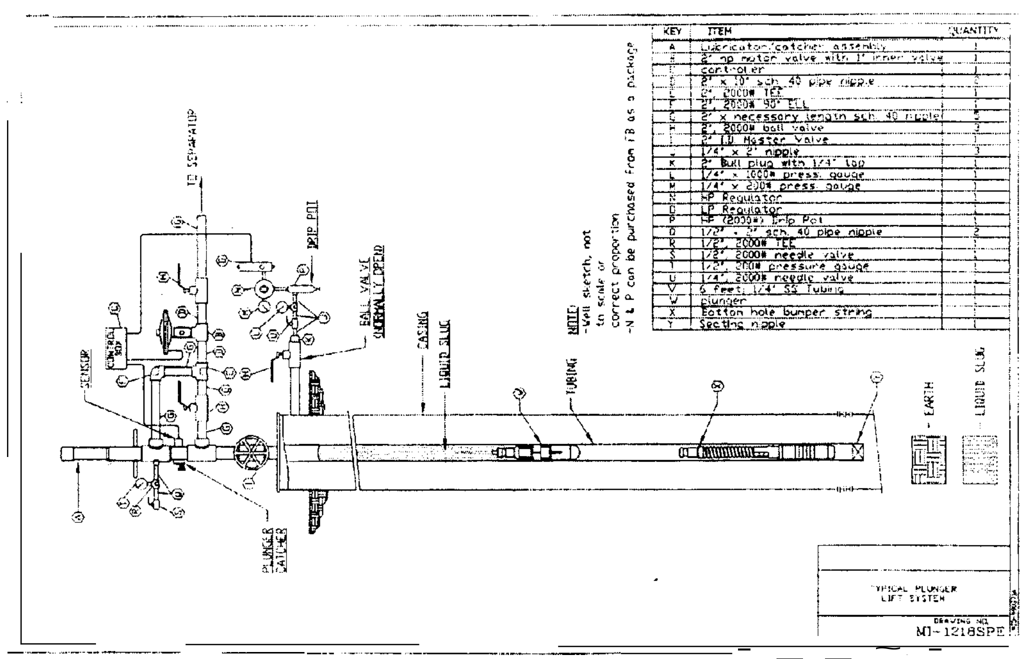

Figure 4 - Typical Tubing Flow Plunger Lift System

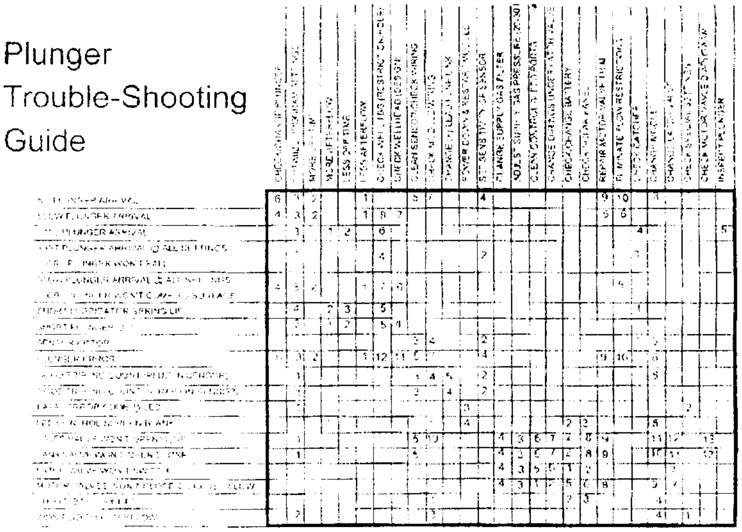

Figure 5 - Trouble-Shooting Chart for Plunger-Lifted Wells On the left are symptoms of plunger lift problems with solutions listed across the top in order of most likely. This chart applies best to electronically controlled plunger systems that run on time vs. pressure. (Modified version of Fig. 9 of Ref. 7)

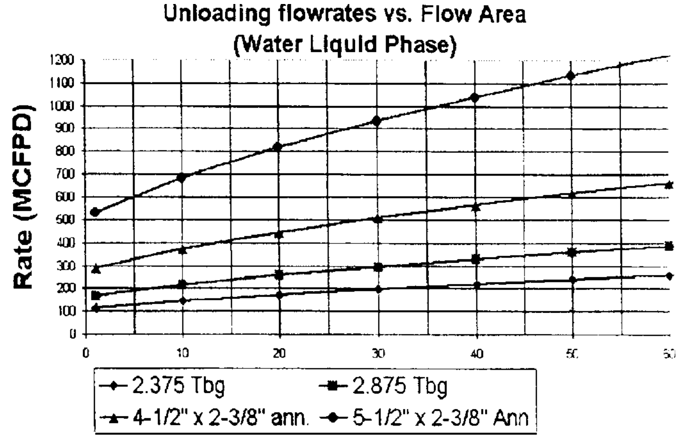

Figure 6 - Unloading Curves for Tubing and the Corresponding Annulus.
Rate vs. psia. Pressure range is 25–32 psia

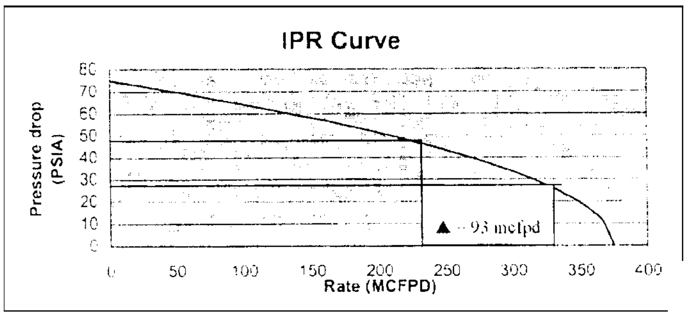

Figure 7 - IPR Curve for Gas Well Making 240 MCFPD with a 45 psia Casing Pressure
Reducing the casing pressure to 25 psia will result in a 93 MCFPD increase. Pressure vs. rate

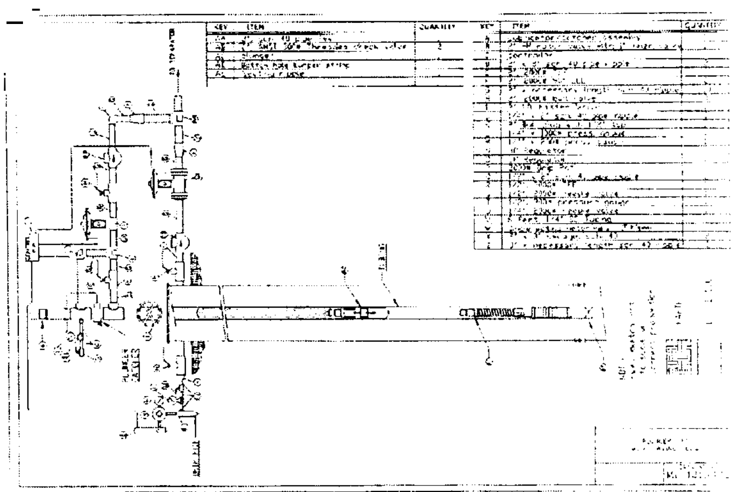

Figure 8 - Plunger Lift System with Casing Flow

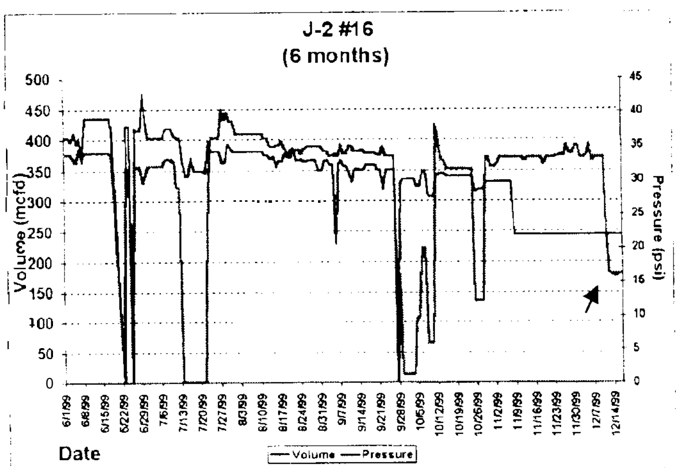

Figure 9 - Daily Gas Production Plot Taken from Intranet
The arrow indicates tubing flow only.

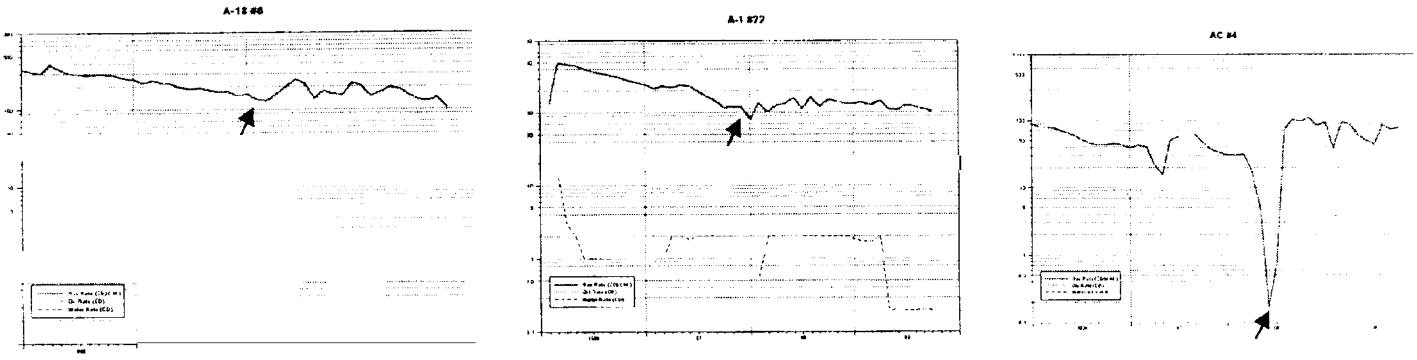

Figure 10 - Plunger Lift Installations with Annular Flow Once Liquid Loadup Occurred
Arrow indicates plunger lift installation.

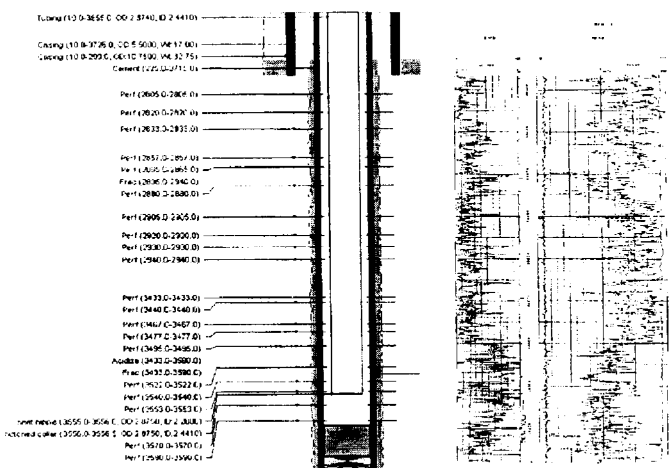

Figure 11 - Typical Downhole Tubing Placement Relative to Porosity Log
Note stringers below the end of tubing.

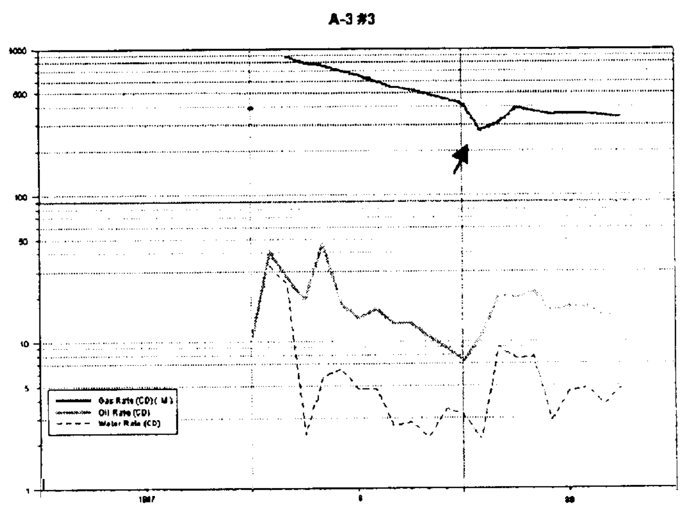

Figure 12 - High GLR Oil Well Put on Annular Plunger Lift
Paraffin cutting was required once to twice per week prior to plunger lift installation,