REPLACING BEAM PUMPING UNITS WITH PLUNGER LIFT

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ABSTRACT

Converting beam pumping wells to plunger lift drastically cuts costs, improves profit, and keeps marginal producers profitable. This paper discusses one such case for a West Texas Field. The majority of the wells converted to plunger lift showed equal or more oil and gas production after the conversion. Some of the wells increased gas production by almost 200%. Twenty-one wells (41% of the total number of wells) have currently been converted to plunger lift, saving chemical treatments .both for corrosion and paraffin. Other benefits include reducing failures; eliminating rod pump repairs, rod parts, electrical costs and reducing environmental liabilities such as stuffing box leaks.

Other savings include an increase in the return on capital employed (ROCE) by removing surplus equipment from inventory. The sale of surplus equipment pays for at least two plunger lift systems.

This discusses well selection criteria, field results, new technologies in plunger lift operation, and related benefits.

INTRODUCTION

Amoco's Midland Farms Deep Unit wells were commingled (two-four zones opened in a single well bore) starting in 1984. The zones common to the wells are the Fusselman, Devonian, Atoka, and Strawn. These wells came on strong but declined over the years. These 53 wells produce an average of about 15 barrels per day of 42 API gravity oil and commonly little water The bottom hole temperature is 195 degrees. Casing sizes are 5.5" and 7".

Fiberglass rod strings were installed in all of the wells to accommodate the liquid volumes combined with the depth (average depth 11,700'). As production declined, this type system was expensive and inefficient. Paraffin control was a huge problem. The fiberglass limited hot oil temperatures and therefore effectiveness. Chemical costs were a big burden. In some cases the wells would have to be stripped (pull tubing and cut fiberglass rods to get out of the hole) when the paraffin had the rod string stuck. This required replacing the fiberglass rods in addition to cost of removing the paraffin and the cost of the pull.

Gas interference was another problem with no apparent solution. Spacing a well with fiberglass rods at a depth of 12,000' can be quite an adventure. Close spacing of the pump is desired to get good compression in an attempt to handle gas more effectively. This is what brought up the question of "how make the gas work for us" instead of being a hindrance.

PLUNGER LIFT

Background

A typical plunger lift application is illustrated in Figure 1.

The typical plunger lift system requires removal of the sucker rods and pump; it also requires placement of the seating nipple within 50 feet of the top of the perforations. The seating nipple is the stop for the bumper spring assembly. The plunger will lift fluid from this point. At the surface a master valve is installed on the tubing for isolating the remaining wellhead assembly and for easy retrieval of the plunger. The lubricator is screwed into the master valve and includes the flow tee, plunger sensor, top bumper spring (to cushion the plunger upon arrival at the surface) and the catcher that enables the operator to remove the plunger. The motor valve is downstream from the flow tee to control the plunger cycles or trips.

A microprocessor controller, which is the brains of the system, is mounted on the motor valve. The controller keeps up with the time it issues the command to open the valve to the time it receives a signal from the plunger sensor that the plunger has arrived at the surface. Some of the controllers use pressure sensors to operate, but all of the controllers in this field example work on time. Operational data, such as depth, is entered into the controller so it can calculate desired plunger velocity. From the depth setting and desired velocity a target is calculated. The controller then calculates a percentage of deviation from this target that is acceptable and creates a window of good arrival times. If the arrival time is within this window the controller assumes no adjustments are required. If the arrival times are below the window (fast) the controller assumes that the off time, or pressure build up, was excessive and reduces the off time for the next cycle. Inversely, if the controller senses that the arrival time was above the window (slow), the off time was not sufficient and adds time for the next cycle.

This system requires no packer because the well produces into the annulus during the off time to store enough energy to lift the plunger during the next cycle.

Operation

With the plunger in the catcher in the wellhead, gas flows for a set time or until a pressure drops to a control value. Then the control valve is shut in and the plunger is allowed to drop. Sufficient time must be allowed for the plunger to drop before the well is opened again. As the plunger is dropping and after it hits the bumper spring, pressure is building in the casing and in the tubing as well. The plunger depends primarily on the pressure stored in the casing for the energy needed to surface the plunger and liquids on the next cycle. That is why no packer in the well is a necessity for nearly all installations, unless holes are perforated from the tubing to the casing above a packer (if one is there) preferably below the bumper spring.

While the plunger is on the bumper spring, liquids accumulate in the tubing and in the casing as well. Since the tubing is a lower pressure than the casing when the well is shut-in, initially the liquid will tend to go into the tubing above the plunger. However, for long shut-in periods, the liquid level in the casing and the tubing probably equalize.

When a set is time reached, (some controllers on the market use pressure), the well is opened, and the plunger begins to travel upward with liquid above it, and usually with some liquid below. The purpose of the plunger is to prevent excessive liquid fallback as the plunger and liquid slug or slugs travel to the surface of the well. Without a plunger in the well, use of a controller to intermittent the well would allow much of the liquids that accumulate in the bottom of the well to fall back before reaching the surface. This makes the process much less efficient, or even unworkable.

In general, excessive back pressure or separator pressure is detrimental to the cycle. Large slugs of liquid require more casing pressure before the well is opened. Larger plungers take better advantage of the well pressure to lift liquid because of the area of the plunger. However, large plungers can cause damage if they come up dry. One caution (Reference 6) is to not try to surface the plunger if the difference between the casing and tubing pressures (shut-in) exceeds 40-50% of the difference between the casing and sales or separator pressure. If this occurs, the well should be shut-in longer or even swabbed or nitrogen lifted if this situation can not be alleviated. An example of this rule is:

Casing pressure (600 psi) - Tubing pressure(500 psi) = 100 psi (possible indication of load)
Casing pressure (600 psi) - Separator pressure (100 psi) = 500 psi (driving force)

100/ 500 = only 20% so it is apparently ok to open the well and expect surfacing of the plunger.

Previous Studies

There have been a number of papers published discussing selection criterion for plungers. Some of these are listed in the references in this paper. Reference 1 is a paper that correlates some data from the Ventura field in California for 2" and 2 1/2" plungers. The data listed in this paper shows the 2" plungers in 5 1/2" , 7" and 11 3/4"-7" casing. The data for the 2 1/2" plungers is mostly for 7" casing. The data is correlated and application charts are generated, some of which (discussed below) are still in use today.

In 1965, Foss and Gaul (Reference 2), developed a more mathematical model of plunger performance. The model was designed to deliver the plunger and liquid slug to the surface with an assumed average velocity of 1000 feet/second. The model also assumed 2000 feet/second for fall through gas and 172 feet/second for plunger fall velocity though liquid. The main result of their very thorough work, was to develop a model for the casing pressure which must be present to be sure the plunger and slug would surface. Of course, this requires a determination (from pressures, or production data, etc.) of the slug size.

The main Foss & Gaul formula's are:

Pcasing, minimum = (Pp + Pt + (Plh + Plf)) (1 + D/K)

Where: Pcasing is the casing pressure just as the plunger and liquids surface (@ 1000 ft/sec average velocity)
Pp is the pressure needed to lift the plunger, psig (about 5 psi)
Pt is the sales pressure or separator pressure, psig
Plh is pressure needed to lift the weight of liquid per barrel, psig
Plf is the pressure needed to overcome the liquid friction in the tubing, psig
(Plh + Plf) was determined to be about 165 for 2 3/8 inch tubing and about 102 for 2 7/8 inch tubing
D is the bumper spring depth, feet
K is a factor to account of the gas friction in the tubing (about 33,500 for 2 3/8's tubing and about 45,000 for 2 7/8's tubing. Note: this can be found mathematically)

So the casing pressure needed before opening the well is P casing, max

Pcasing, max = (Aa + At) / Aa) (P casing, minimum)

Where: Aa = cross section area of the annulus between the casing & tubing
At = cross section area of tubing inside area

Hacksma (Reference 3 combined Foss and Gaul results with the IPR to determine the effects of available gas on plunger performance .

White (Reference 4) presented a model of plunger lift in an intermittent gas lift well. His work contains expressions to explain liquid fallback. Some results indicated that a hole in the center of the plunger increased plunger performance. Lea (Reference 5) presented a model calculating the changing pressures, and forces on a plunger as it rises to the surface. Reference 6 by Rosina includes some laboratory tests and critiques of other models compared to his.

Reference 7 includes some practical guidelines to selection of plunger lift. References 8 and 9 discuss the critical velocity in a well. When the gas flows below the critical velocity, the gas does not lift the liquid efficiently and liquids accumulate in the well and can stop production. When this situation occurs, tubing re-sizes, or lowering well head pressure can be implemented. Another approach is to use plunger lift.

Selection Criterion

There are many selection criterion, some very simple and others more complex using the results of the references discussed above. From Reference 7 the mention is made of the test that the well should produce about 400 scf/(bbl-1000 feet). Example:

Well data: GLR = 4000 scf/bbl, depth = 5000 ft. Is this well a candidate for plunger lift?

GLR/(depth/1000) = 4000/5 = 800 scf/(bbl-1000 ft)

Since this is greater than a "needed" 400 scf/(bbl-1000ft) the well is assumed to be a candidate.

Another test is the use of figures from the oldest reference listed in this paper, Reference 1. These figures are shown as Figures 2 & 3 (for 2 and 2 1/2 inch plungers). These figures are in terms of net pressure and GLR (gas-liquid ratio) and depth. Why are they still used? They are correlations from data and are very easy to use. Often times data is not available to use more sophisticated methods anyway. Example of use:

Depth = 5000 ft
GLR = 4000 scf/bbl
Plunger size = 2 inch
Casing pressure = 400 psi
Separator pressure = 100 psi

Net operating pressure = 400 - 100 = 300 psi

Entering Figure 2, at 300 psi and going to 5000ft (between 4000 and 6000 ft) and reading to the left, it shows about 3,300 scf/bbl is needed. Since the well is stated to have 4000 scf/bbl, then it should be a candidate. It is interesting to note that in Reference 1, the authors state that you should enter the chart with a depth equal to the actual depth minus 2000 ft. If you do this, then only about 1500 scf/bbl or less is needed for the well to be a candidate. It is unknown if this practice has apparently been done away with to make the prediction more conservative, or because it is more accurate (from experience) to not subtract the 2000 feet. It is definitely more conservative to not subtract the 2000 ft.

In this field example candidates were selected by using figures such as Figure 2 and 3, and a computer program developed om studies originating from References 2 & 5. (output example is Figure 4). This approach is to insure that the well has sufficient gas (GLR) and build-up pressure to operate with plunger lift. Usually a gas well is loading with liquids and you have data on the gas and perhaps not the liquid production which must be estimated. In this case, the wells were on beam pump. It was known that the wells are gassy and gas interference was limiting the wells production. Initial data indicated that the wells were candidates from using the charts in Figures 2 and 3. Actually as the work preceded, even as data was scarce, it was economic to go ahead and try plunger lift compared to performing more extensive well tests and comparing to charts and computer programs. One well was selected by the fact that the well was blowing considerable amounts of gas during a pull.

RESULTS

The results of oil, gas, and water production before the conversion and 30 days later are shown in Table 1. Figure 5 is a typical installation in the Midland Farms Deep Operations.

The majority of the wells converted from beam lift to plunger lift either equaled or surpassed oil and gas production. The average increase in oil was 2 barrels per day per well. The average gas increase, on wells with available data, was 83 mcf per day per well. Even though some wells showed a decrease in oil production, huge increases from other wells have kept total production for the lease above normal. Initially all of the wells were produced from the Devonian, because this zone was the suspected gas producer. During evaluation of the lift revisions, all of the wells equaled or surpassed the production of the beam pump in a 30 day period .

At 60-90 days an oil production decline became evident in a some of the wells. The decision was made to lower the tubing to the bottom zone (Fusselman). The results were very encouraging. One well was producing 6 BOPD on beam and after 60 days on plunger, decreased to 5 BOPD on plunger lift (first well in Table 1). After lowering the tubing to the bottom zone, production has leveled out at 19 BOPD. Because of another well, the allowable for a 5 well lease was exceeded and had to be raised. Currently all of the wells that were not set at the bottom zone during the initial conversion are being lowered and it became standard practice on new installations. Even with lost oil production the well profitability was greater due to the drastic cut in expenses. This allowed us to keep producing wells that were not profitable on beam lift.

Electrical costs were eliminated. The controller is operated by batteries and a solar panel keeps them charged. Paraffin treating expenses were eliminated because the plunger wipes the tubing every time it makes a trip to the surface. Paraffin was a major problem in this field. It is approximately 30% of the well expense. Well servicing expenses decreased. Environmental liabilities are reduced through the elimination of stuffing boxes. Rod strings, pumps, and pumping units were actualized as surplus.

CONCLUSIONS

Plunger lift is a cost efficient method of artificially lifting low liquid volume oil wells. This type lift keeps marginal wells producing and increases profit on other wells. Some of the wells discussed in this paper would have been shut in due to high costs on beam lift. With the plunger lift system they are now economic with low daily liquid production rates.

The plunger lift installations are paid for by the liquidation of surplus equipment. Plunger lift made 19, conventional 640 pumping units and 2, conventional 912 units surplus. These beam units were sold or used on other Amoco properties. Return on capital employed is increased through this process.

References:

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Table 1

TBG	TBG	CSG	PRODUCTION BEFORE			PRODUCTION AFTER (30)			DATE	
SIZE	DEPTH	SIZE	OIL	WATER	GAS MSCF	OIL	WATER	GAS MSCF	INSTALLED	REMARKS
2.375"	10693'	7"	6	1	233	5	1	676	7/19/93	LOWER TO 11730' 11 4/94 OIL PROD 19 BBL
2.375"	11239'	7"	4	2	230	6	1	NA	9/16/94	
2.375"	11774	7"	15	1	260	15	1	345	5/2/94	9/26/94 LOWERED FROM 10824
2.375"	11860	5.5"	15	1	345	20	1	NA	6/20/94	USING SUPPLY GAS FROM AK 2'1
2.375"	11850	7"	16	1	120	8	0	NA	3/22/94	
2.375"	11750	7"	14	2	230	8	0	NA	3/15/94	
2.375"	11673	7"	13	2	240	33	11	531	1/12/94	28 OIL AFTER 90 DAYS
2.375"	11015	7"	17	0	120	11	0	NA	7/14/94	
2.375"	11774	7"	10	1	285	10	1	NA	9/9/94	
2.375"	11980	5.5"	12	2	180	16	3-	180	5/2/94	10/94 LOWER FROM 10972
2.375"	10792	7"	5	2	250	5	2	500	10/20/93	7/94 USE AS SUPPLY WELL FOR AK196
2.375"	10859	7"	6	2	95	12	0	75	1/19/94	LOWER TO 11860' 11/4/94
2.375"	10856	5.5"	13	1	125	14	0	125	6/27/94	GAS TESTING PROBLEMS
2.375"	11042	7-5"	6	1	55	13	2	55	4/7/94	GAS TESTING PROBLEMS
2.375"	11800	7"	45	6	120	40	0	175	1/7/94	8/94 LOWERED FROM
2.375"	11926'	5.5"	16	3	160	17	3	334	1/14/94	9/26/94 LOWERED FROM 10997'
2.375"	11930'	5.5"	7	12	180	6	6	80	7/14/94	8/22/94 LOWERED FROM 10924'
2.375"	11139	5.5"	15	4	215	21	2	399	10/18/94	30 DAY TST 11/12/94
2.875"	11008'	5.5"	8	8	122	12	7	124	4/7/94	
2.375"	11025	5.5"	5	10	68	9	1	23	5/5/94	TRIPS ONE TIME PER DAY
2.375"	10915'	5.5"	5	7	70	6	4	NA	6/15/94	TRIPS ONCE EVERY 36 HOURS
	11413		12	3	176	14	2	259		

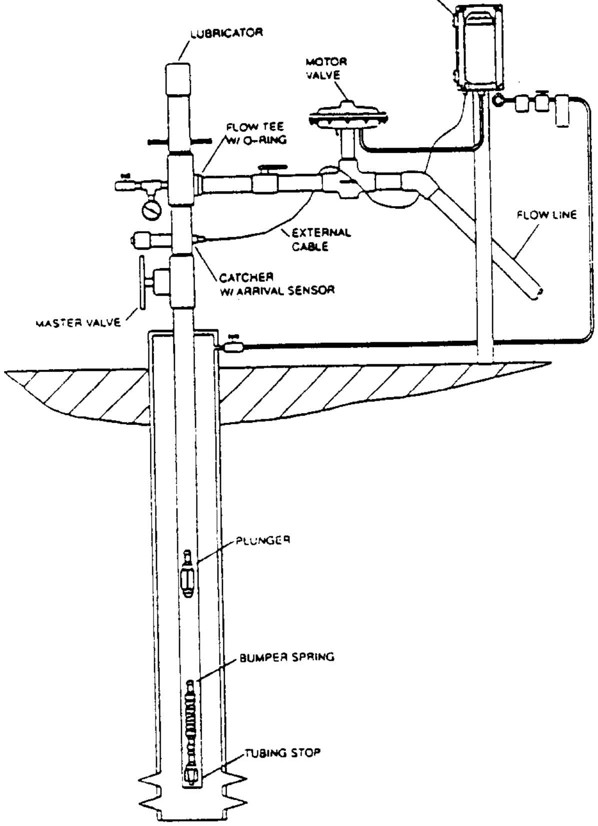

Figure 1 - Typical Plunger Lift Installation
Option II

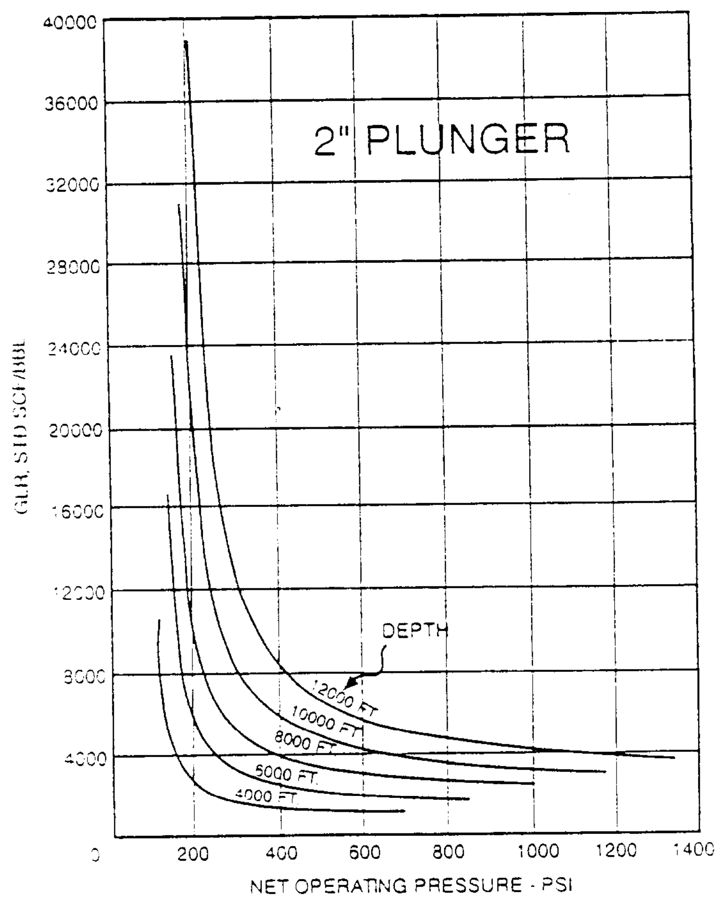

Figure 2

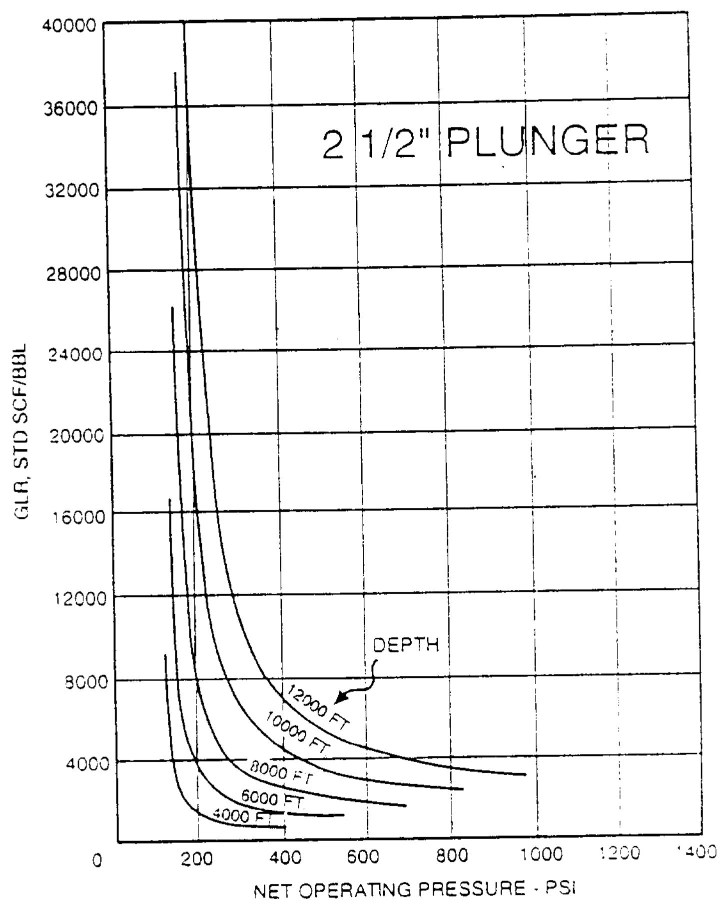

Figure 3

--- RESULTS: MIN GLR AND CSG OP PRESS. , REQUIRED GLR AND GAS ---

SLUG SIZE .BBLS	PMIN .PSI	AVG BHP .PSI	REQ'D CSG OPER PSI	REQ'D MIN GLR,SCF/BBL	PROD. MSCF/D	[illegible]	[illegible]
0.12	72	126	119	25308	17	2	40
0.23	67	131	112	12462	32	4	[illegible]
0.34	101	148	124	9323	47	6	[illegible]
0.45	115	168	141	7963	62	8	4
WELL GLR= 7500. OPERATE AT LOWER REQUIRED GLRS-\/ \/							
0.56	129	189	159	7222	78	10	0
0.67	144	210	177	6721	93	12	0
0.78	158	231	195	6365	108	14	0
0.89	172	253	213	6097	123	16	0
1.00	186	274	231	5888	138	18	[illegible]
1.12	201	295	249	5720	153	20	0
OPER CSG PRESS = 250.			/\ /\ OPERATE AT LOWER REQUIRED P[illegible]				
1.23	215	316	267	5583	168	22	0
1.34	229	337	285	5469	182	24	[illegible]
1.45	243	359	303	5372	197	26	0
1.56	258	380	321	5288	212	28	[illegible]
1.67	272	401	339	5216	227	30	0
1.78	286	422	358	5153	241	32	[illegible]

SEE ADDITIONAL LINES OF OUTPUT? ENTER=YES, 1=NO?

Figure 4

Figure 5