PLUNGER LIFT WITH GAS ASSIST

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ABSTRACT

With today's economics in the oilfield, many operators are searching for ways to cut lift costs. Plunger lift is often considered. However, if it is projected that a particular well does not have sufficient gas to operate a plunger, this means of artificial lift is no longer considered.

For instance, if a particular well shows to be 10 MCF per day below operating requirements, an operator may spend upwards of $50,000.00 to rod pump this well. An alternative would be to add 10 MCF per day to this well through gas injection. Many operators have high pressure gas available without realizing. Many have compression for gas sales, some have gas plants, and others have high pressure gas wells. All these examples are avenues that should be explored.

This paper examines such scenarios in two West Texas fields.

PLUNGER LIFT WITH GAS ASSIST

Wells 1 & 2 (table 1) were being produced on intermittent gas lift. The operator was interested in cutting lift cost. Both wells were using over 300 MCF per day to reach maximum production. Packers were released and annulus pressure was restored using gas injection and natural buildup. When valve opening pressures were reached, tubing and casing equalized. Initially the valves helped unload the wells, but as casing pressure requirements dropped, valve operations ceased. Both wells actually increased oil and gas production, even though injection was cut 41%. At an estimated cost of $.25 per MCF, both wells' savings were in excess of $11,000 per year.

Wells 3, 4, and 5 (table 2) were formerly on rod pump. Because of previous success in this field, all three were tried on conventional plunger lift. Well 3 was a very successful installation, however, wells 4 and 5 were not as successful. #4 produced on plunger lift, but rates were somewhat less than on rod pump. #5 was not successful at all, only averaging one plunger trip per day. It was determined to allow #3 to build it's annulus pressure and try to operate #5 with an annulus tie-in. #5 became a success, but the operator lost most of its production from #3. It was determined to use a gas compressor, thereby restoring production on well #3, as well as continuing production on #5, and an added benefit of optimizing production on #4. Production from all three wells has exceeded former production, as well as reducing operating cost and creating surplus equipment.

All five wells currently cycle on minimum plunger fall time. Upon plunger arrival, no afterflow (sales delay) is permitted, minimizing gas injection demands. This practice increases the number of plunger cycles therefore increasing fluid production.

PLUNGER LIFT OPERATION

Plunger lift is a form of intermittent gas lift usually operating from the natural buildup of pressure during shut-in of a well bore. The suggested system has open-ended tubing to allow gas to be stored in the annulus to be utilized as lift gas during flow. However, there are many successful plunger lift systems operating under a packer.

During shut-in well production increases wellbore pressures. Some wells may actually push the liquid out of the wellbore back into the formation when certain pressures are reached. When flow is resumed, this compressed energy (gas) expands driving the liquid in the production string towards the surface. The plunger (pig) is used as an interface between the liquid and gas to minimize liquid fallback. It also functions as a scale and paraffin scraper. Some theories hold that the high velocity of liquid return to surface as well as minimal fallback is the reason paraffin doesn't form.

Plunger cycles are determined by the frequency of buildup to an operating pressure that will return the plunger to surface at a velocity of around 750 feet per minute. Example: Well depth=7500' divided by 10 minute per arrival = 750' per minute. Velocity over 1000 feet per minute are normally too fast and velocities slower than 500 ft per minute are near plunger stall speeds and well loading may occur.

PLUNGER LIFT CRITERIA

The most important factor for plunger lift operation is gas/liquid ratio. A standard rule is considered 400 scf of gas, per barrel, per 1000' lift depth. An example would be a well producing 50 MCFPD, 5 bbls total fluid, at a lift depth of 5000 ft. Divide SCF per day (50,000) by barrels per day (5). Then divide the product (10,000) by well depth (per 1000') equaling 10 and the remaining product is 1000 scf. The well should now be considered a plunger lift candidate. This factor should be doubled for packer operation.

The second most important factor for plunger lift operations is pressure. Pressure requirements are almost impossible to compute for packer applications, but for communicated (open-ended) tubing minimum operating pressure can be calculated. The first formula would be deducting flowline pressure from casing buildup (Example: 500 - 50 = 450). This is the available lift gas pressure. This directly affects the amount of hydrostatic fluid that can be lifted. The second is casing pressure to tubing pressure differential. Tubing pressure less flowline pressure should be at least one half of casing pressure. Under such conditions wells should always be shut-in upon plunger arrival until conditions improve.

Larger tubing sizes are generally more successful due to lower hydrostatic pressures per barrel, as well as the increased lift area a larger plunger provides. Tubing size must be consistent and well tree size should also be consistent.

Other important factors are flowline restrictions (i.e. length and diameter), surface chokes, and production equipment.

Plunger lift is normally considered a solution to paraffin and scale problems, however, sand production can be detrimental to plunger lift.

CONCLUSION

Plunger lift is associated with low cost and low maintenance. However, not all wells will operate a plunger lift system. As this paper shows, it may still be economical to operate a plunger lift system with some type of gas injection. A plunger system with gas injection will probably be more successful than systems without in marginal wells, due to increased cycle frequency, as well as additional gas volume to avoid plunger stall. Increasing the gas to liquid ratio will actually lower the pressure requirements for lift, thereby increasing inflow from the formation.

Table 1

Wells produced on intermittent gas lift

Well #	Oil	Water	Gas (mcf/day)	Gas Injected (mcf/day)
1	15	2	84	300
2	25	2	50	375
Total	40	4	134	675

Wells produced on plunger lift with gas assist

Well #	Oil	Water	Gas (mcf/day)	Gas Injected (mcf/day)
1	18	0	84	178
2	32	2	127	221
Total	50	2	211	390

Table 2

Beam Lift Operation

Well #	Oil	Water	Gas(mcf/day)
3	5	2	250
4	12	2	180
5	15	1	NA
Total	32	5	430

			Equipment Made Surplus		
Well #	Unit size	Surplus value	Horsepower	Rod string	Surplus value
3	640 conv	$26,000	75	f.g./steel	$6 900
4	640 conv	$26,000	60	f.g./steel	$6 900
5	640 conv	$26,000	75	f.g./steel	$6 900
	Total	$78 000	210		$20 700

Plunger Lift With Gas Assist

Well #	Oil	Water	Gas(mcf/day)
3	5	2	300
4	25	0	124
5	20	1	196
Total	50	3	620

Equipment Purchased to Supply Lift gas

	Compressor	Installation cost	Total
Cost	$17 633	$19 000	$36,633