CASING PLUNGERS SUCCESSFULLY REPLACE CONVENTIONAL ROD PUMP AND JACK IN SOME TEXAS AND OKLAHOMA PANHANDLE WELLS

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ABSTRACT
Recent innovations in casing plunger cup design and mechanical actuation indicated success in artificial lift applications currently using a conventional rod pump and jack. Several wells, previously produced by tubing plungers with limited success, and subsequently equipped with conventional rod pump and jack, were chosen for field testing fluid removal using casing plungers. The objective was two-fold. First, test the feasibility of a casing plunger as a possible replacement of rod pump and jack, and thereby reduce lease operating expenses. Second, compare the overall production of casing plungers with rod pump and jack performance. Early results and successful installations indicate casing plungers can be considered as rod pump and jack replacements in many applications. Casing plungers might well be considered prior to rod pump and jack installation. Production data, conversion costs, well selection criteria, and observations will be presented.

HISTORY

Casing plungers have been successfully used as an efficient and economical method of artificial lift in some Texas and Oklahoma gas wells experiencing liquid loading problems. Continued development and innovations and recent patents granted have successfully extended the applications for casing plungers to efficiently remove liquids and increase or maintain gas production. As experience and confidence increased, even broader applications were considered. One well was restored to production after a casing leak repair failed to be 100% successful and has previously been presented in this forum. Another area considered focused primarily on reduction of lease operating expenses more than an increase in production. This led to several field applications in which wells produced with conventional rod pump and jack were considered due to excessive field maintenance cost. Frequently, paraffin presents aggravating and expensive problems. Traditionally, hot oil and chemicals are the solution of choice and generally precede any well work. Another area considered was excessive maintenance expenses of motors and bearings on pump jacks. While these expensive repairs have been around so long as to seem normal, the decision was made to evaluate the replacement of traditional rod pump and jack with a casing plunger and compare the methods of artificial lift.

FIELD TEST

One well, Ruth 1-36, has been chosen for the focus of this paper. Several other wells have also been field tested with variations in conditions and results. The Ruth 1-36 was drilled and completed in Beaver County, Oklahoma in 2003. Multiple sets of perforations in the Morrow and Chester formations were commingled from 7546 to 7772. After completion, including acid and fracture treatments, the well was equipped for traditional rod pump and jack production. Production began in October 2003 and after treatment recovery, averaged 7500 mcf, 200 barrels of oil, and 120 barrels of water per month. Within 6 months, the production had declined to 6000 mcf, 200 barrels of oil, and 40 barrels of water per month. By early 2005, further decline to 5500 mcf, 200 barrels of oil, and 30 barrels of water per month was observed. By normal standards, this had been a successful well and payout was achieved ahead of schedule. By this analysis, no reason for modification existed.

However, during this same time, this particular pump jack and motor were experiencing unusual repair and maintenance expenses. See TABLE 1. Even though such excessive expenses occur more often than is admitted, this circumstance became the focus of a discussion to consider a casing plunger to compare the production by another method of artificial lift. In addition to the rather unusual expenses incurred, the normal lease operating expenses associated with pump jack operations were ongoing. A focus on the use of lease fuel gas for motor operation was also considered. A motor consuming 5 mcf/day in fuel consumption was a tolerable $300 per month loss of revenue at $2/mcf gas. But at $10/mcf gas, that same fuel consumption represented a loss of revenue of $1500 per month. During the short time that the Ruth 1-36 was on rod pump and jack, the rod pump failed. During the normal pump change, the pump parted and left a portion in the seating nipple. Swab recovery of the fluid standing in the tubing was unsuccessful due to paraffin buildup inside the tubing.

Casing plunger installation: The April presentation of this paper will include actual photos of the well head conversion and casing plunger equipment installed on the Ruth 1-36. These additional photos do not lend themselves to this paper format. The descriptions herein will be enhanced by the additional information shared in the presentation.

Because the operator had experienced the successful replacement of a rod pump and jack with the installation of a casing plunger on a different well with excessive paraffin problems, the decision was made to lay down the rods and tubing and install a casing plunger in the Ruth 1-36 for production test comparison.

The flanged well head was removed and a bell nipple with threads looking up was installed on the casing string. The full port ball valve and plunger lubricator assembly were installed on the well head. The rods and tubing remained on location during this test period. A wire line unit with 3/16 inch braided line and special tools was rigged up to run a specially equipped casing scraper to the top perforation. Even though the well was essentially new, there were several tight spots in the casing inside diameter. These frequently occur during running the casing and consist of tong or slip crimps and even sometimes excessive make-up torque coins the casing pin to obstruct the casing diameter. After the determination that the casing wall was suitable for casing plunger operations, a collar stop was set at 7507 in the first collar above the top perforation at 7546. The casing plunger lubricator was plumbed into the flow lines, supply gas lines and blow down lines. The casing plunger was then dropped into the well bore from within the lubricator. The well head was further equipped with a controller that would sense plunger arrival, operate two flow valves and hold the plunger within the lubricator for optimum production efficiency prior to initiating the next plunger cycle.

EXPECTATIONS

It was hoped that the casing plunger would produce a volume of fluid and allow the sale of gas and oil that would be the economical equivalent of the rod and pump jack installation. In other words, some reduction of sales volume of gas and oil might still yield the same economic advantage of the higher volume offset by higher expenses of operation. The expense of operations with a casing plunger consisted of periodic cup changes and the occasional need of a wire line unit, should a cup change cycle be delayed. A distinct hourly cost advantage existed with the wire line unit over the traditional double drum workover rig. No revenue was lost due to gas consumed as motor fuel on the lease.

RESULTS

To the delight and surprise of all, the production actually increased substantially over that of the rod pump and jack. Further, paraffin problems encountered in the tubing have been eliminated by the wiping action of the casing plunger. In fact, evidence to date favors the presence of some paraffin as an aid to reducing wall friction of the cups under the load of fluid. The combined benefits observed now open the door for further evaluation of traditional rod pump and jack installations. Increased production, elimination of down hole paraffin buildup, reduced operating expenses, and reallocation of valuable tangible assets are significant considerations.

The increase in production for the remainder of 2005 can be observed in FIGURE NO. 1. The incremental gas sales for April through December were approximately 18,000 mcf representing over $125,000 additional revenue at a modest $7 gas price. The average sales volume with the casing plunger of 7555 mcf per month exceeds the sales rate of 5465 mcf with rod pump and jack by over 2000 mcf per month. The dip in sales volume in September was the result of 5 days lost sales due to high line pressure, but no loss of gas actually occurred. FIGURE NO. 2 shows the oil production for 2005. The incremental oil recovered of approximately 340 barrels from April through December represents additional revenue of $18,700 at $55 oil. TABLE NO. 2 indicates a typical decline for total fluid produced. The incremental revenue provided a payout of less than 2 months and continually represents substantial savings in reduced monthly lease operating expenses.

CONVERSION COSTS

The cost to convert from rod pump and jack varies from well to well. Generally, typical expenses to lay down rods and tubing prevail. Any mechanical failures with the pump, tubing and/or tubing anchor can cause substantial variations in costs. Removing flange well heads are more involved than threaded tubing/casing heads and company safety policies permit or restrict some procedures. In the current market, the salvage value for the rods, pump, tubing, and jack more than cover the cost of conversion. The cost of a typical casing plunger system is about $12,000 with a basic controller. Specific well conditions may cause that cost to vary somewhat. Still, very attractive payout has been achieved with the combination of increased sales, reduced operating expenses and salvage value of assets.

CASING PLUNGER MAINTENANCE COST

In the Ruth 1-36, cup life of 300 cycles has been reliable. Current production program maintains 4 complete plunger cycles per day. The cup life of approximately 2 months more than justifies the cost of about $260 per set of cups. Of course, casing with different conditions will have a substantial effect on cup life. Cups are replaced in the field by trained personnel within the normal scope of lease pumping operations. About ½ hour should be ample time for cup replacement after retrieving the plunger from the well head lubricator.

WELL SELECTION CRITERIA

While each application will need to be evaluated individually, some general guidelines are available. Depth is not a limitation with sufficient gas flow rate and surface conditions. Of course, the greater the reservoir pressure differential over the surface gathering system pressure, the better. Gas rates of 300 mcf/day and fluid volumes of 25 barrels per day were achieved in the Ruth 1-36. Other wells with a GOR above 5000 have also worked successfully. Experience suggests that conversion is more likely successful before reservoir depletion leaves no other alternative to the rod pump and jack. At least 50 psig differential of BHP over surface gathering pressure should be available. Gas rates as low as 20 mcf per day and fluid volumes of 3 to 5 barrels per day have also worked successfully.

CONCLUSIONS

Some rod pump and jack installations removing accumulated fluids of oil and water from gas wells are viable candidates for evaluation of casing plungers to remove accumulated fluids and maintain, or increase gas production and concurrently reduce lease operating expenses. These candidates should be evaluated individually. Further, as the need for installing rod pump and jack to remove accumulated fluids comes under consideration, a casing plunger should be evaluated as a viable alternative before the expense of rodding up and installing a pump jack is incurred.

ACKNOWLEDGEMENTS

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TABLE 1

PUMPING UNIT AND MOTOR REPAIR AND REPLACEMENT RECORD	
Sep 03	Set Big M 228-246-86 PU w/ C-96 gas motor on concrete base
Nov 03	Replace main bearing in C-96
Jan 04	Replace piston in C-96
Jan 04	Repair clutch on C-96
May 04	Install new motor rails on pump unit
Jul 04	Replace intermed. & hi spd shaft brgs, new hi spd gear in PU
Jul 04	Repair and weld base on PU
Nov 04	Repair starter on C-96
Jan 05	Replace bridle on Big M PU
Jan 05	Repair clutch on C-96

Table 2

PRODUCTION DATA: MARLIN OIL--RUTH #1					
DATE	GAS, mcf	OIL, bbl	SW, bbl	TOT, bbl	COMMENTS
Jan 05	5955	210		210	
Feb 05	5491	195		195	
Mar 05	5465	180		180	Install PAL 3-23
Apr 05	8015	317	33	350	
May 05	8356	272	42	314	
Jun 05	7230	252	48	300	
Jul 05	7440	239	51	290	
Aug 05	7227	254	42	296	
Sep 05	6314	177	24	201	Down 5 days due to high line psi.
Oct 05	7491	210	24	234	
Nov 05	7847	210	21	231	
Dec 05	8077	195	33	228	

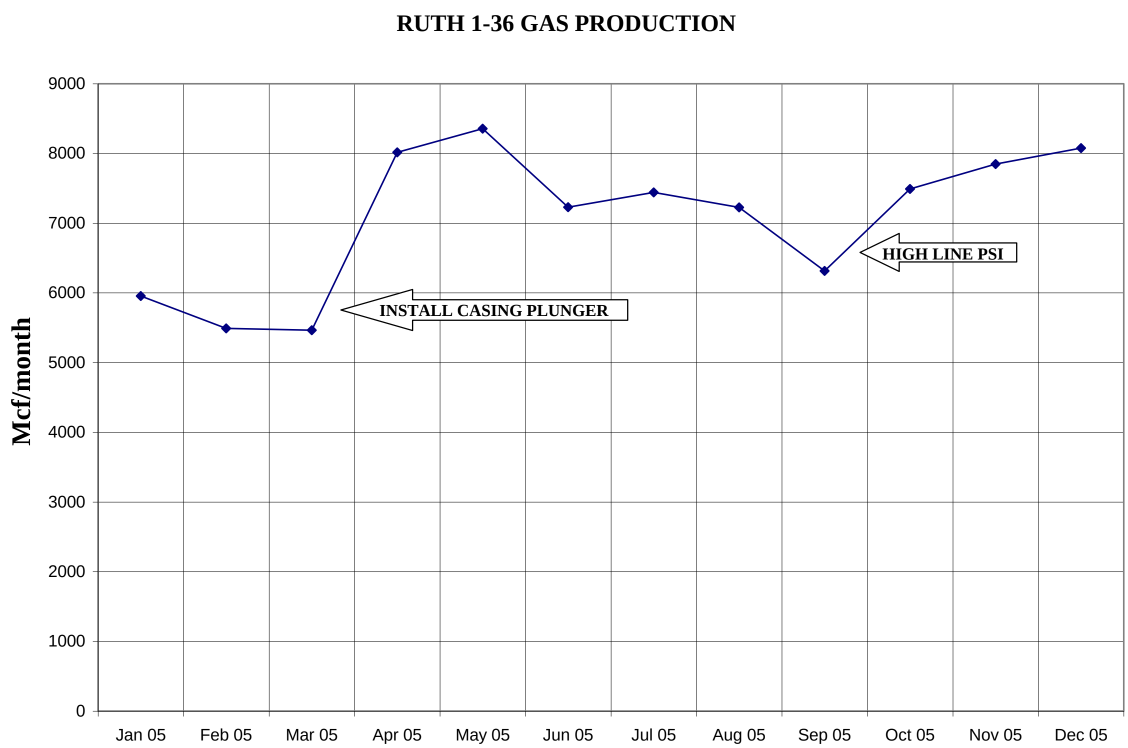

Figure 1 - Gas Production

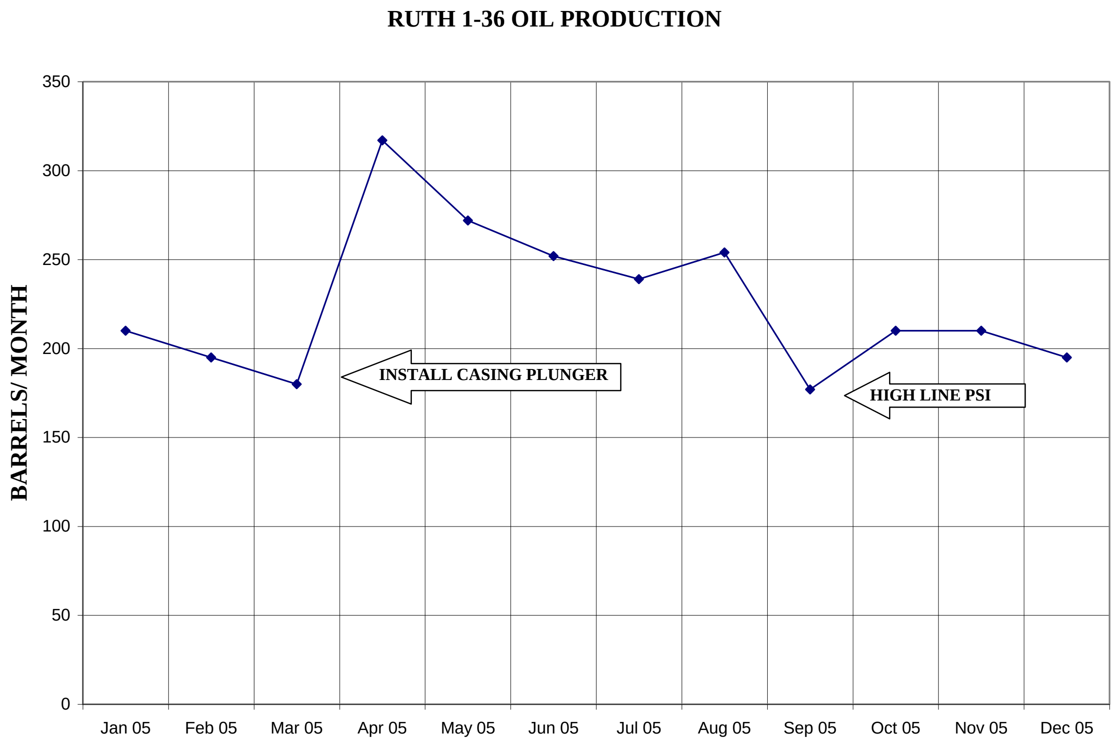

Figure 2 - Oil Production