A REVIEW AND SUMMARY OF INNOVATIONS AND APPLICATIONS FOR CASING PLUNGERS IN GAS WELLS

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ABSTRACT

During the past 4 years, successful field applications for casing plungers have been extended through recently patented innovations in design. This paper will review and summarize the technical progress in casing plungers. A variety of field applications will be reviewed and a summary of results will be presented. Actual economics of successful applications will be presented. Criteria for well selection, based on the comparison of best and worst case results, will be detailed. Probable expectations will be demonstrated through charts of actual well results.

HISTORY

Recent innovations and patents modifying the mechanical design and function of sealing cups in casing strings, often consisting of various weight (pounds/ft) sections of casing, have extended the range of applications for successful casing plunger operations. The significant cup design modification that permits a cup outside diameter to be at or near the casing inside diameter at the bottom of the well essentially eliminated tool hang up on descent. This cup design modification enabled wells with casing leaks repaired by squeeze cementing to be included with potential candidates for casing plungers. Mechanical reconfiguration and design, covered by multiple patents, permits the sealing cups to be mechanically and pneumatically actuated to seal against the casing wall only at the bottom of the cycle. Further, the relocation of the flow bypass valve to near the top of the plunger enabled the internal cavity of the plunger to be used as a chamber in which gas pressure can increase sufficiently to seal the cups and lift the plunger and accumulated fluid to the surface, usually against line pressure.

This paper will briefly review and summarize the advances in technology over the past 4 years and the various field applications and subsequent developments that have occurred. The results, conclusions, and recommendations of many installations will be presented. The primary wells utilized in these field tests have been in the Texas and Oklahoma panhandle gas fields.

APPLICATIONS

Although most of the wells had 4 ½ inch casing, 3 wells were tested with 5 ½ inch, 15.5 #/ft casing. Most of the 4 ½ inch cased wells were at depths of 5000 to 9000 feet and generally employed varied casing weights common to standard practice for the area. Frequently, the 4 ½ inch casing string encountered had 11.6 #/ft at the top and bottom with a middle section of 10.5#/ft. However, one well had 11.6 #/ft top and bottom with 9.5 #/ft in the middle. A few wells were uniformly cased with a single weight of either 11.6 or 10.5 #/ft. Shallower wells generally had a single weight casing.

The initial wells tested were low volume gas wells with fluid loading problems. Typically, tubing plungers either did not work any longer, or worked only with very long shut in times for pressure buildup and short high rate spikes of gas sales with very little after flow. This technique simply maintained some production. Other methods of fluid removal such as soap and swabbing were ineffective and economically unattractive. Choosing wells near the end of the economic production life produced both good results and defined the lower limits of effective applications. **Chart No 1. and Figure No. 1** depicts the results of converting to a casing plunger that would travel to the bottom of the well through an old casing leak repaired by squeeze cementing. Also visible is the negative effect that bacterial sludge agitated by the increased sales volume of the casing plunger caused. After mechanical removal of the sludge and acid cleanup the casing plunger significantly increased the gas production by over 10 fold. **Chart No. 2 and Figure No. 2** show much more modest increases in gas production. In other cases, the fluid contained oil or condensate and further enhanced the economic success of the installation.

One unusual, but highly successful, application followed a failed second attempt to repair a casing leak with the familiar squeeze cement technique. The continual influx of water from the leak area, in addition to formation water and water invasion from the leak prior to repair, prohibited the successful resumption of the tubing plunger installation in use prior to the leak. The decision was made, prior to converting the well to rod pump, to try a casing plunger. Initial attempts with the casing plunger were erratic and sensitive to line pressure fluctuations. Fortunately, the ability of the plunger to fall through the cement repaired portion of the casing was to our advantage. Finally, it was determined that the fluid level would quickly rise to the maximum extent provided by the reservoir pressure. The collar stop was moved to the mid-point of the water column. Then after swabbing the fluid level down to the stop, the casing plunger could repeatedly and consistently remove the leak fluid and the invasion and formation fluid. Production was immediately restored to over half of the daily volume prior to the leak. **Chart No. 3 and Figure No. 3** show the recovery of production over a period of months. The fluid level slowly dropped until the fluid production was 2-4 bbl/day. Then the collar stop was lowered to a depth just above the top perforation. Once again the fluid production increased to 12-15 bbl/day and slowly began to drop in daily volumes as experienced earlier. Gradually the gas production increased to 75-90 mcfpd. This well, 3 years later, is now back to the original decline slope and still has not had the casing leak fully repaired.

Each successful application opened the door to examine and evaluate other possibilities. A good well making over 220 mcfpd and 6-8 bopd was producing from formations at a depth of 7500 feet. Fluid was removed by conventional 228 pump jack and rod pump. This particular pumping unit experienced various mechanical failures and fluid production fell off and gas sales declined to under 200 mcfpd. The decision was made to evaluate a casing plunger on a good well. The rods and tubing were laid down and the casing and wellhead prepared for a casing plunger installation. The results were amazing. **Chart No. 4 and Figure No. 4** show the increased gas sales that resulted from efficiently removing well bore fluids that had accumulated during an extended period of unusually frequent mechanical failures and repairs. Not only did the fluid production immediately increase, but the gas sales increased to over 270 mcfpd for several months. This data indicates that when the pump unit was down, gas sales continued, though gradually declining as fluid loading occurred. When the casing plunger, making repeated and consistent trips, began to unload the fluid, the gas production not only increased, it actually exceeded the sales rate for the period prior to the removal of the pump unit. After several months of successful production with the casing plunger, the rods, tubing and pumping unit were moved to other locations. This well continues to produce efficiently and economically with a casing plunger.

After this experience with replacing a pumping unit, other wells on pump were evaluated and wells were chosen on the low end of the production range to determine the limits of successful pump unit replacement. Bottom hole pressures and line pressure ratios were critical. The gas to liquid ratio in cubic feet per barrel was also critical. It was determined that even though sufficient pressure build up might indicate success, a more critical factor was the GLR (gas liquid ratio). While the casing plunger would cycle at the lower GLR's of 5000-7000 cf/bbl, the cycle time could be as long as 1-2 days. If the fluid produced was oil, the monthly reduction in total oil volume produced proved to be economically unattractive in the current market of $70/bbl. Since the pump unit was in place, it was concluded to be cost effective as the production method. The key was the saleable oil volume produced monthly. The reduced gas production while lifting water might be cost effective if the power cost to lift water were considered. But if the fluid production was oil, current market conditions favored pumping oil at steady daily rates to maintain uniform monthly cash flow.

Two wells, one with 4 ½ inch and one with 5 ½ inch casing, producing oil with very little gas production but with substantial bottom hole pressures were evaluated. The 4 ½ inch well was 30 years old and had never been connected to gas sales, but had enough gas to run the Ajax motor. Pressure build up of over 300 pounds triggered the evaluation. After several months of cycles that could take a week or more, the decision was made to replace the tubing and rods and resume pump production. The 5 ½ inch well was new. After a few months of initial low volume oil and gas sales, the decision was made to evaluate a casing plunger to see if the pumping unit could replaced and used elsewhere. The plunger did cycle and lift 5-10 barrels of oil per cycle. However, the cycle times were excessively long and irregular. Better economics occurred by resuming the conventional gas motor powered pump unit as the primary production method.

WELL SELECTION CRITERIA

During the past 4 years, a wide variety of well conditions, depths, production volumes, surface pressures and equipment have been evaluated. The current state of the art in casing plungers indicates a reasonable expectation of success under these general conditions. The depth is not critical since successful installations from 2000 to 9000 feet have occurred. The casing inside diameter needs to be uniform within the range of standard weights for a specific casing outside diameter, i.e. various weights of 4 ½ inch casing can occur within the casing string (9.5, 10.5, or 11.5 #/ft). The only 5 ½ inch casing evaluated to date has been 15.5 #/ft, but other weight casing can be accommodated reasonably. Consideration must be given to available full port ball valves and sequence of various weight casing in the casing string. Currently, no casing plungers are suitable for a tapered casing string of 5 ½ inch to 4 ½ inch within the same well bore. Any casing inside diameter anomalies created by downhole tools, permanent packers, casing patches or sections repaired by squeeze cementing must be evaluated on a case by case basis. However, success in several wells repaired by squeeze cementing can be documented. Composition of well bore fluids may require the use of sealing cups specifically matched for best performance and cup life. Surface roughness of the casing walls is also critical to cup life. The bottom hole shut in pressure should be at least 50 psig higher than anticipated gathering system pressures to lift fluid from 9000 feet. The pressure required to lift the weight of the casing plunger is less than 10 psig. Cycles lifting larger volumes of fluid are more effective with higher margins of available bottom hole pressure compared to line pressure. The most critical factor is the gas to liquid ratio. For wells that need to unload fluid every day to maintain gas production, the GLR most successful exceeds 15,000 cubic feet per barrel. Other wells that gradually load up may be successful at a lower GLR in the range of 7000-12,000 cubic ft/barrel. A few wells were successful in lifting a barrel of fluid at low pressures and flow rates by allowing fluid to accumulate over a period of days and accepting a cycle time that could be several days. This was an aid to weak wells that experience fluid loading over a period of weeks and cannot justify swabbing or pump unit installation.

In those cases in which a casing plunger was installed and evaluated and later removed, conventional production equipment was easily replaced and the production method of choice was reinstated.

ECONOMICS

The economics of any investment in the oil and gas industry must depend on the market value of the product sold. Currently, the record high prices of natural gas become a concern for gas consumed in lease operations, such as motors, compressors, or venting practices that reduce product sold into the pipeline. Some installations may be worthwhile in simply reducing the lease losses and becoming sensitive to the environment. Other installations simply offer a more cost effective method to removing water, condensate and oil. Condensate and oil offer the advantage of sales while water becomes an expensive waste product.

If fluid loading is restricting gas sales, a frequent occurrence, the increase in sales may quickly payout the expense of installing or converting to a casing plunger. In those cases in which rods, downhole pump, tubing and pumping unit can be replaced and reassigned to other uses, the cost of installation may be entirely offset by the salvage value of the assets replaced. The installation costs vary from well to well, depending on casing condition and surface well head equipment. And, consequently, the payout for installing a casing plunger can vary from a few weeks to several months. Generally, the increased production and improvements in lease operating costs easily offset the purchase price and installation expenses of casing plungers.

A cursory review of the production charts presented will substantiate very attractive payouts for successful casing plunger installations.

CONCLUSIONS

The state of the art continues to advance in the use of casing plungers to remove well bore fluids from gas wells, increase gas production, improve efficiency, free expensive assets for reassignment, and be sensitive to the environment. The range of well conditions that benefit from installation of casing plungers continues to increase. As producers define the successful parameters and best conditions, expertise in field operations and utilization will continue to expand. Casing plungers have been successfully used in many wells in the Texas and Oklahoma panhandle gas fields. Older wells with casing integrity issues have been addressed and now successfully produce with casing plungers. Field equipment and practices are compatible with routine operation, maintenance and cup replacement. In some cases, pumping units have been replaced and production has been maintained or even increased. The critical factor will often be the GLR (cubic feet of gas per barrel of fluid) if no mechanical obstructions remain. Current market prices make casing plungers an attractive method of artificial lift worthy of consideration and evaluation.

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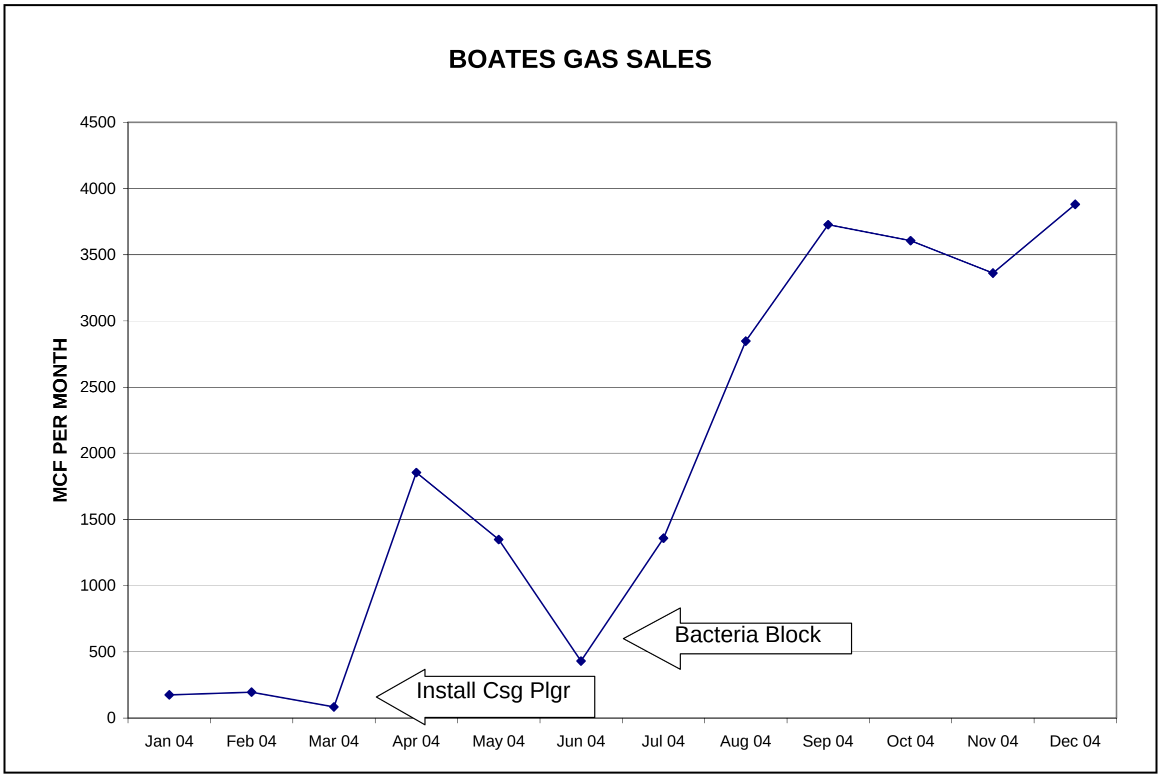

Chart 1 - Boates Gas Increase

Figure 1 - Boates Well Head

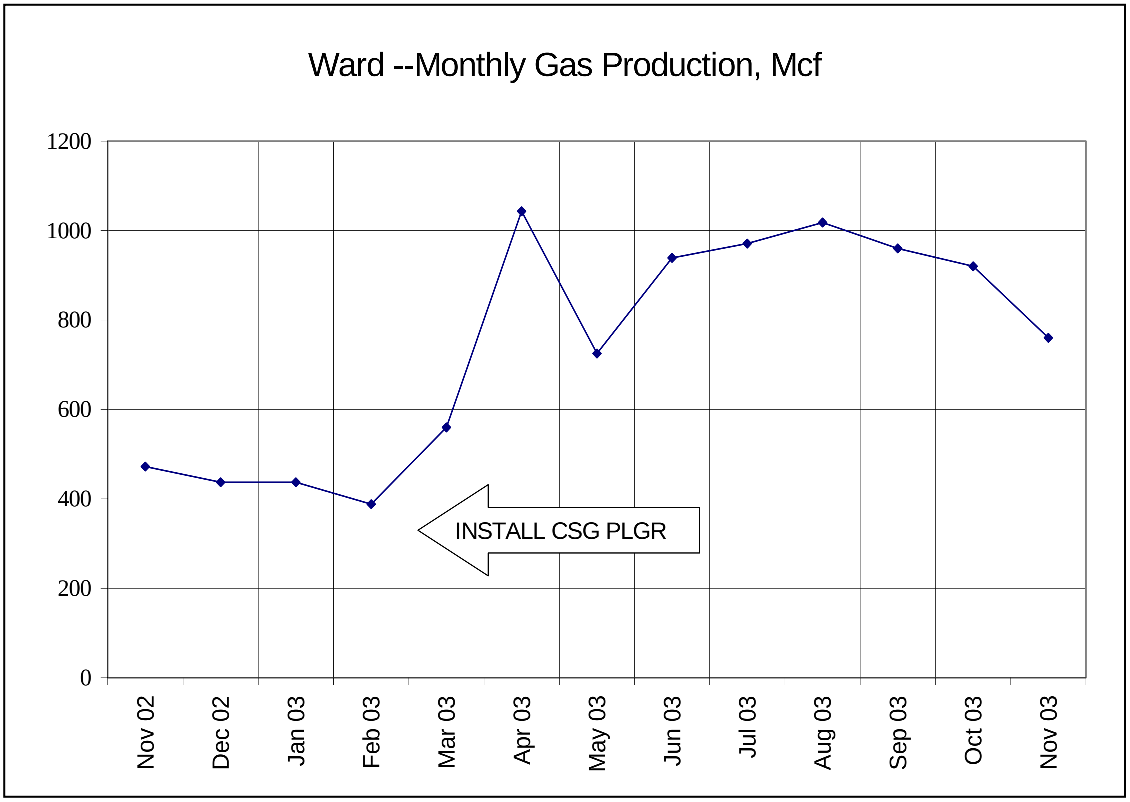

Chart 2 - Ward Gas Increase

Figure 2 - Ward Well Head

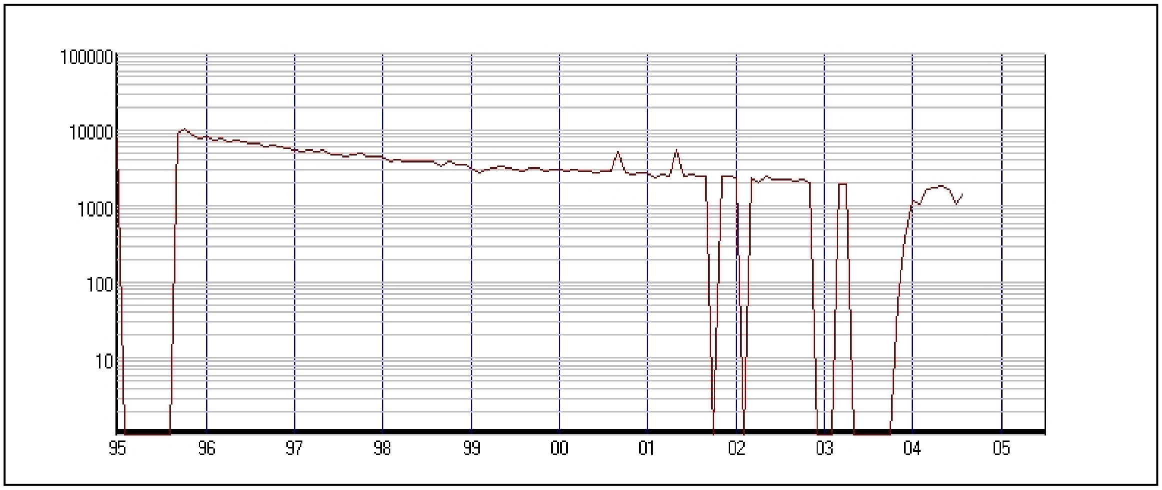

Chart 3 - Celestine
Monthly gas production with conventional tubing plunger until a casing leak in early 2003 caused loss of all production. Unavailable workover equipment delayed repair until late 2003. Repair attempts were not totally successful. Restoration of production using the tubing plunger also failed. Prior to installing a pumping unit, the well was converted for a casing plunger in December 2003. After modifying the production method, gas sales were restored and have now returned to the predicted decline curve. The well remains on casing plunger production.

Figure 3 - Celestine
Conventional tubing plunger replaced with casing plunger after casing leak was not completely repaired.

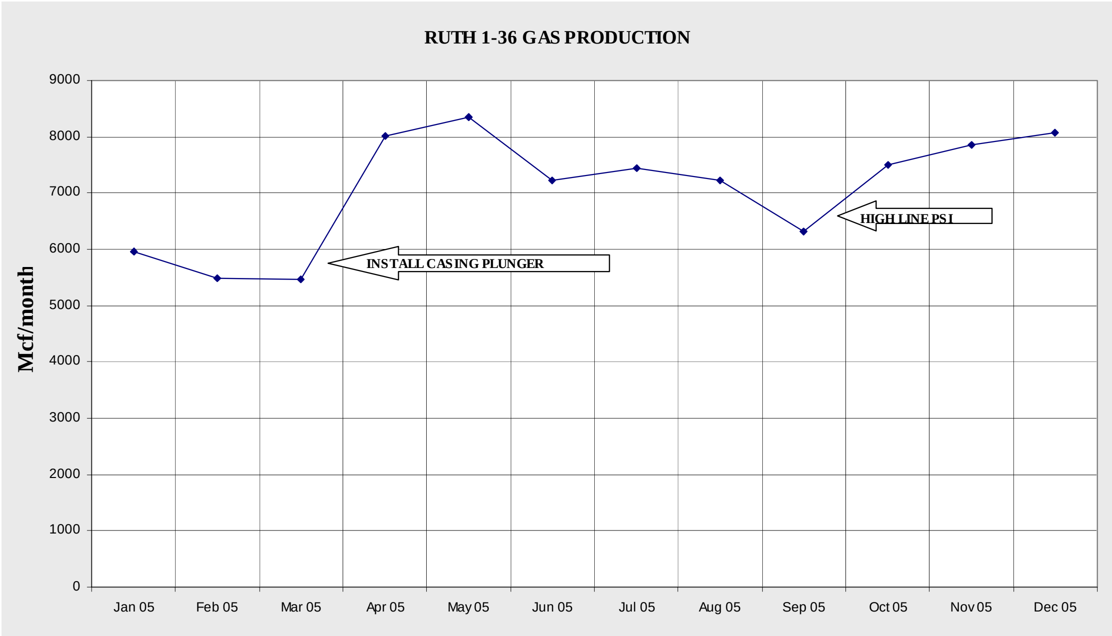

Chart 4 - Ruth Gas Increase
228 Pump Unit Replaced With Casing Plunger

Figure 4 - Ruth
Replace 228 Pump Unit with Casing Plunger