EXTENSION OF TYPICAL CASING PLUNGER TECHNOLOGY TO 5 ½ INCH CASING WITH NON-UNIFORM CASING WEIGHT STRINGS IN TEXAS AND OKLAHOMA PANHANDLE GAS WELLS

Robert L. Moore, PE, PAAL., LLC
Windel O. Mayfield, Lone Star Rubber

ABSTRACT

Recent developments of casing plunger technology have provided reliable tools that successfully remove well-bore fluids and reduce liquid loading in marginal or stripper gas wells producing in 4 ½ inch casing strings of non-uniform casing weight. These advances are the result of better selections of elastomeric compounds suitable for variations in the casing inside diameter that occur with non-uniform casing weight strings in deeper wells. Significant advances in the mechanical design permit more efficient sealing of the elastomeric sealing cups with the casing inside diameter variations encountered in non-uniform strings. The specific difficulty presented by 5 ½ inch casing is the much larger variations in casing inside diameter that exist in common casing weights used in deeper wells. The status of field tests and current results will be presented as part of the ongoing development of casing plungers in broader applications.

HISTORY

Recent innovations and new patents available to the industry have successfully broadened the range of applications in which casing plungers can be used to remove well bore fluids from low volume gas wells unable to sustain the critical, or entrainment, velocity necessary to remove fluids from deeper wells common in the industry. Patented improvements in the mechanical actuation critical to the proper functioning of casing plungers have dramatically increased the reliability and opportunities for successful installations. Additionally, advances in the formulations of compounds selected have produced elastomeric cups that react with more stability and longer wear in many applications. Field engineering procedures have obtained specific well bore data that have led directly to improvements in the engineering design of sealing cups with improved performance characteristics. Well head equipment has been redesigned to facilitate ease of handling and field redressing of plungers.

BARNETT SHALE

While many improvements have occurred in the design and utility of casing plungers, by far, most of the successful installations have been in various weights, or combinations of weights, in 4 ½ inch casing. Heretofore, successful installations in 5 ½ inch casing have predominately consisted of a single continuous weight casing. The innovative casing plunger was successfully installed in 7 new Barnett Shale vertical wells in Cooke County, Texas in the fall of 2008. See appendix for details. These wells were almost 9000 feet deep and completed with 17#/ft 5 ½ inch casing. Perforations from roughly 8000 to 8600 feet and consisted of multiple sections of perforations over the 600 feet interval.

Conventional pump jacks and tubing plungers were used to remove the frac fluids and formation fluids. The improved conventional casing plungers were installed within the static fluid column above the top perforation, typically at about 8000 feet. In each well, the collar stop was placed higher than the top perforation until sufficient fluid had been removed to allow the collar stop to be lowered to just above the top perforation. A period of several months was required for this fluid removal to successfully occur. In some cases, the improved conventional casing plunger successfully replaced a conventional pump jack installation as the sole source for fluid removal.

The wells in the Barnett Shale were drilled and completed with 5 ½” 17 #/ft casing. Typically, the top of the formation was at 8000 feet and the bottom was at 8600 feet. Standard flanged well heads were initially installed. Prior to the installation of the casing plungers, the tubing was removed, and then a packer was set in the casing on tubing at about 1500 feet. The remainder of the tubing was removed, the packer was covered with water and the B-section and well head were removed. A standard 5- 1/2” bell nipple with 8rd thds was welded onto the top of the casing. The well was then fitted with a full port 5-1/2” 2000 psig ball valve and with the lower section of the casing plunger lubricator installed. Then the casing packer was retrieved and all the tubing laid down. Of course, those wells being produced with rod pump and jack had the rods and pump retrieved and laid down. The upper section of the casing plunger lubricator was installed. The casing was then conditioned with a casing scraper, the collar stop was set at the selected depth, and the casing swabbed down to scattered fluid above the collar stop. The well head casing plunger lubricator was plumbed into the production lines and the casing plunger was dropped into the casing. The descent and ascent of the plunger travel was monitored with an EchoMeter Model M fluid level instrument. The fall rate of the casing plunger provided instant confirmation that the plunger was descending into the well and below the static fluid level. Similarly, the rate of ascent could be easily determined to confirm satisfactory performance. The initial fluid levels were higher than well reservoir pressure could lift. Consequently, the collar stop was raised higher in the fluid column, the fluid swabbed and the casing plunger returned to operation. This method allowed the reservoir pressure to lift the upper portion of the gas cut fluid column and the plunger with regularity.

During the 2 ½ years these wells have been operated with casing plungers, several critical factors were identified and resolved. Excessive sand was encountered in some wells that adversely affected the sealing cup life and the lubricator catch mechanism. Sealing cup compounds were altered to provide longer life during sand production. After the sand was cleaned up, the sealing cup compounds were changed to provide longer life and better lift efficiency. As the result of cup compound modifications and more optimal production cycles of the casing plungers, cup life is now approximately 6 to 8 weeks per set of cups. As the result of testing 7 wells in close proximity, an improved cup design was tested and proved to be superior to the previous design. The improved design is now available for general use. Five of the original seven wells are still producing with casing plungers.

Over this time period, the static fluid level of these wells has been lowered through the efficient use of casing plungers. These wells have now had the collar stops lowered to just above the top perforation and recover the accumulated fluid above the top perforation that occurs between plunger cycles. These wells are now ready to be evaluated as candidates for production with the HYBRID CASING PLUNGER to discover if additional production benefits can be realized by removing standing column of gas cut fluid over the 600 feet of perforated intervals.

A further comment has been observed on those wells in which a casing plunger replaced the conventional rod pump and jack. The gas production has been essentially maintained at a constant rate. However, the monthly oil production was reduced with the use of the casing plunger compared with the pump jack. The significant factor to be considered is the lifting cost per barrel of oil. The casing plunger provided a lift cost advantage of such significance that the actual net profit of the well has increased with the use of a casing plunger. While the oil production rate dropped on a monthly level, the drastically reduced operating cost of the pump jack was eliminated and resulted in substantial improvements in the profit of production. A benefit of this scenario is the preservation of oil in place that can, perhaps, be produced at some time in the future at higher prices while maintaining a favorable profitable return on investments provided by the lower lifting costs.

During the past two and one-half years, the improved conventional casing plunger clearly demonstrated the efficient removal of well bore fluids and maintained, or improved, gas production. Field personnel have discovered and identified the unique characteristics of individual wells. Through careful observation and variations of the plunger run cycles, optimum operation plans have been developed for each well. This resulted in longer cup life and maintained level production. Casing plunger trip cycles vary from daily to a few days apart to sometimes as much as 10 days between trips. Fluid recovery may be as small as a few barrels per cycle to as much as 30 barrels per cycle. Some trip cycles occur over night while others require 1 or 2 days to complete. The casing plunger is held in the well-head lubricator while gas flow continues until the predetermined time occurs for the next cycle. This type of well familiarity is essential to achieve the optimum performance and production improvements casing plungers offer. These wells are now ready for the next stage of fluid removal from the lower perforations with the use of a HYBRID CASING PLUNGER, a modification and improvement to remove fluids from lower perforations while maintaining the collar stop above the top perforation.

OTHER AREAS

However in other areas, the majority of older wells, especially those drilled during tough economic times, generally present a 5 ½ inch casing string consisting of a typical combination of heavier, lighter, heavier casing. Typical combinations encountered will be 17# top and bottom with 15.5# mid-string sections. And similarly, a 20# top and bottom with 17# mid-string sections is also encountered with wells that presented higher initial bottom-hole pressures.

And then there are the surprises. One such well in the Texas panhandle is such a case.

The well was drilled in 1959 to a depth of 6500 feet and completed as an oil and gas well. Over the years most of the usual productions methods available were used. Rod pumps and tubing plungers in 2 3/8 inch tubing were the primary methods used after the initial flow cycle ended. By early 2005 when this well was acquired, production was maintained by a tubing plunger with erratic monthly production. The gas production was about 10 mcf/day and oil production varied from 30 barrels per month to 60 barrels per month, depending on the tubing plunger performance drastically affected by paraffin in the tubing. Various chemical treatments proved unsuccessful.

Finally in 2010, the decision was made to remove the tubing and install a casing plunger. Casing plungers will typically work in high paraffin conditions better than tubing plungers since the casing plunger cups actually wipe the casing walls on each cycle. One other well presenting high paraffin conditions operated for over 10 years before the accumulated casing wall paraffin became a problem. A simple mechanical treatment of tripping down the casing with a casing scraper restored production and normal performance of the casing plunger. So the presence of paraffin was acceptable.

The well file only indicated the original casing was 5 ½ inch with almost no other details. Searching the files revealed that 14#/ft, 15.5 #/ft and 17#/ft 5 ½ inch casing had been used. So much for reliable well file data. It looks like the pipe rack was emptied. The B-Section and well head were removed and presented 15.5 #/ft 5 ½ inch casing at the surface. The initial casing plunger cup selection was for 15.5 #/ft casing with the hope that the weight of casing plunger would assist the descent through wherever the 17#/ft sections were. This did not occur and the casing plunger would hang up on descent. The casing plunger was fished using a standard swab rig. The well was swabbed and 30 barrels of oil were recovered. The casing plunger was pushed to the bottom, thinking that with some wear on the cups the plunger might fall. The casing plunger made a cycle to the surface and carried 9 barrels of oil and increased the gas rate to over 80 mcf/day. This confirmed the wisdom of installing a casing plunger to assist and improve production. The casing plunger is now equipped with cups for 17#/ft casing but still will not ascend all the way to the surface without mechanical assistance. Another cycle of swabbing recovered 30 barrels of oil and once more the casing plunger was pushed to the bottom and made a cycle and recovered another 9 barrels of oil and increased the gas rate to over 80 mcf/day.

At this time, continued experimentation with various cup sizes and configurations of cup design are being evaluated. Running a casing wall roughness survey would locate the different weight casing sections, but the cost of such a survey is in excess of $7,000 and considered out of budget at this time. Hopefully by the time this paper is presented, better solutions will have been achieved.

The wells in the Barnett Shale were drilled and completed with 5 ½” 17 #/ft casing. Typically, the top of the formation was at 8000 feet and the bottom was at 8600 feet. Standard flanged well heads were initially installed. Prior to the installation of the casing plungers, the tubing was removed, and then a packer was set on tubing at about 1500 feet. The remainder of the tubing was removed, the packer was covered with water and the B-section and well head was removed. A standard 5- 1/2” bell nipple with 8rd thds was welded onto the top of the casing. The well was then fitted with a full port 5-1/2” 2000 psig ball valve and with the lower section of the casing plunger lubricator installed. Then the casing packer was retrieved and all the tubing laid down. Of course, those wells being produced with rod pump and jack had the rods and pump retrieved and laid down. The upper section of the casing plunger lubricator was installed. The casing was then conditioned with a casing scraper, the collar stop was set at the selected depth, and the casing swabbed down to scattered fluid above the collar stop. The well head casing plunger lubricator was plumbed into the production lines and the casing plunger was dropped into the casing. The descent and ascent of the plunger travel was monitored with an EchoMeter Model M fluid level instrument. The fall rate of the casing plunger provided instant confirmation that the plunger was descending into the well and below the static fluid level. Similarly, the rate of ascent could be easily determined to confirm satisfactory performance. The initial fluid levels were higher than well reservoir pressure could lift. Consequently, the collar stop was raised higher in the fluid column, the fluid swabbed and the casing plunger returned to operation. This method allowed the reservoir pressure to lift the upper portion of the gas cut fluid column and the plunger with regularity.

During this 15 month test period, several factors were identified and resolved. Excessive sand was encountered on some wells that adversely affected the sealing cup life and the lubricator catch mechanism. Sealing cup compounds were altered to provide longer life during sand production. After the sand was cleaned up, the sealing cup compounds were changed to provide longer life and better lift efficiency. As the result of testing 7 wells in close proximity, an improved cup design was tested and proved to be superior to the previous design. The improved design is now available for general use.

These wells have now had the collar stops lowered to just above the top perforation and recovered the fluid above the top perforation. They are now ready to be evaluated with the HYBRID CASING PLUNGER to determine the additional production benefits of removing gas cut fluid over the 600 feet of perforated intervals.

CONCLUSIONS

In the Barnett Shale wells, an improved conventional casing plunger has successfully demonstrated the effective removal of well bore fluids containing both treatment fluids and naturally occurring well formation fluids. In some cases, the significant advantage of removing expensive assets such as tubing, rods and pump jack were justification enough to replace such assets with the less expensive improved casing plunger. Further, the greatly reduced lifting costs per barrel of oil using a casing plunger instead of the conventional rod pump and jack have significantly increased the profit margin of these wells. Essential to this success was the effort expended to determine each individual well's performance characteristics to achieve optimum production. And in each case, the improved conventional casing plunger successfully removed the well bore fluids and sustained gas production at a higher margin of profit.

BARNETT SHALE INSTALLATION: Typical well conditions, perforations 8000-8600 feet, vertical. Frac fluid and formation fluid removed by rod pump and tubing plunger.

COMPARISON OF CASING PLUNGER AND PUMP JACK PRODUCTION:

BARNETT SHALE VERTICAL WELLS

COMPARISON OF CASING PLUNGER AND PUMP JACK PRODUCTION

	Well No. 1		Well 2	
	Casing Plgr	Pump Jk	Casing Plgr	Pump Jk
Avg	6 mo	5 mo	21 mo	15 mo
Mcf/ day	78	85	20	28
BO/day	1	3	1	3
BW/day	1	7	1	19