CASING PLUNGER RESTORES PRODUCTION AFTER FAILED CASING LEAK REPAIR IN OKLAHOMA PANHANDLE GAS WELL

Robert L. Moore, P.A.A.L., LLC
Windel O. Mayfield, Lone Star Rubber

ABSTRACT

A typical "PAL" casing plunger application was modified to recover fluid invasion after the unsuccessful repair of a casing leak. An Oklahoma Panhandle well experienced a casing leak and shut off gas production. Typical repair attempts to squeeze cement the leak were only partially successful. A small leak was evident due to pressure tests, but an injection rate could not be achieved for further attempts to squeeze cement the leak. Extensive swabbing failed to recover lost fluids and invasion of foreign fluids into the well bore. The tubing plunger used prior to the leak was considered impractical. The usual remedy would be rod pump and jack. A casing plunger was installed to recover both lost fluids and fluid entry after the failed casing repair. Restoration of production rates comparable to rates prior to the casing leak has been achieved. Technique modifications, production charts and economics will be presented.

HISTORY

The well was completed in 1995 as a Morrow gas well from perforations at 6777-6860 feet in Beaver County, Oklahoma. The initial production of 350 mcfpd with 4 bfpd suggested a tubing plunger application. A typical tubing plunger system utilizing well head pressure sensors with production and vent valves worked reliably until mid-year 2003. **Figure 1** shows typical decline and essentially trouble free production. Erratic tubing plunger performance and the presence of LCM in recovered fluids indicated the beginning of a casing leak, which was soon confirmed by loss of production. Swab efforts failed to remove the accumulated fluid and confirmed the evidence of a casing leak. No remedies to contain the fluid loss into the producing zone occurred during the two months required for an AFE to be secured for the repairs.

CASING LEAK

Once the casing leak repair commenced, the tubing was pulled and a RBP was set above the perforations and subsequent pressure tests suggested two leaks. The upper leak was isolated with typical RBP and packer for normal pressure squeeze repair techniques. After the drill out, pressure tests indicated the presence of a small leak remaining. Pressure loss of 275#/5 min seemed excessive. Procedures were initiated to re-squeeze the zone. A suitable injection rate could not be achieved, in fact, it seemed at 2000 psig the squeeze held. Pressure tests of the lower suspected leak were not evident at 1000 psig. The RBP above the perforations was retrieved and the hole circulated clean with coiled tubing and foam.

TUBING PLUNGER INEFFECTIVE

Swabbing operations resumed with the workover rig recovering 96, 85, 71 bf/10hrs. The workover rig was moved out and a swab rig moved in. The starting fluid level was usually about 5400 feet. The swab rig recovered about 48-50 bf/10 hrs. When the recovery dropped to 28 bf/8 hrs, the tubing plunger was reinstalled and the swab rig moved out. The plunger made two trips and the well loaded up and the plunger quit running. A swab rig recovered 41 bf/ 10 hrs showing very salty water, indicating that the upper casing leak was still in fact leaking into the well bore at low pressures. The next 6 weeks consisted of swabbing and trying the tubing plunger. After a few successful plunger cycles the well would load up and the plunger stopped tripping.

PUMPING UNIT CONSIDERATION

The typical solution employed in this situation is to resort to a pump jack and rod pump to remove well bore fluids through the tubing and produce the gas through the tubing-casing annulus. The economic evaluation of the pumping unit consisted of re-conditioned used equipment with gas fired engine, available used rods, new pump and installation estimated at $35,000. Monthly motor fuel consumption was estimated to be $700 per month lost gas revenue sales. The salvage value of the tubing and wellhead equipment were available to offset the installation and cost of a casing plunger. The net installed cost was estimated to be $10,000. The use of a casing plunger for this application was new and offered the additional advantage of advancing the range of applications for casing plungers.

CASING PLUNGER

The decision was made to try a casing plunger. It seemed that fluid production was too high and with the presence of the defective squeeze, the consistent influx of water would be detrimental to the success of the casing plunger. The first objective was to simply recover the invaded fluid from the casing leak, hoping the casing plunger would be more economical than a swab rig. The tubing was laid down, the well head modified for a casing plunger lubricator. **See Figures 2-8.** The casing was broached to ascertain the minimum inside diameter and remove any scale and cement skin remaining from the casing leak repair. The collar stop was set in the 4 ½ inch, 10.5 #/Ft casing at 6732 feet (top perf at 6777). The casing was swabbed and 39 bf were recovered.

The casing plunger was run directly to the stock tank for 10 days on free cycle mode and recovered about 16 bf/day. Based on the gas blow after each cycle, it was decided to place the well on the sales line. Line pressure varied from 40 to 65 psig, with occasional spikes to 90 psig. The gas production immediately averaged 40 plus mcf/day. The casing plunger would run consistently for several days, then variations in the line or malfunctions in the cups would cause the well to load up. Swabbing operations always encountered a fluid level about 5200 feet. The well would swab clean and the casing plunger would run for several days, before loading interrupted the sales cycle. It was decided to raise the collar stop to 5785 feet. This would allow the casing plunger to lift smaller volumes of fluid reducing the effects of line pressure variations. At such time as the fluid production decreased, the collar stop would be lowered to the previous depth just above the top perforations at 6777. Initial fluid recoveries averaged 12 to 16 bf/day.

ELEVATED COLLAR STOP

With the collar stop elevated to the upper portion of the standing fluid column, keeping the well bore clean with sufficient pressure to lift the plunger and accumulated fluid became more reliable. Gas production rates increased to 70 mcf/day and fluid production rates gradually declined to 2 to 3 bf/day. The predictable cup life was established at 75 cycles before the top cup would be replaced. Life cycles in excess of 150 cycles was obtained for the lower cup. Several different cup designs and materials were evaluated. It was determined that the cup life was an acceptable expense compared with the more expensive method of swabbing. In addition, gas sales were achieved comparable to those sales prior to the casing leak.

LOWERED COLLAR STOP

Once the fluid production rate fell to a few barrels per day, the decision was made to lower the collar stop to 6760 feet, just above the top perforation at 6777 feet. The collar stop was lowered, the casing swabbed and the casing plunger was allowed to run to the stock tank for two days to clean up the well. Then the well was put back on line for sales. The daily sale rate averages 70 mcfpd with some days in excess of 90 mcfpd. The fluid recovered increased to over 6 bfpd and after 6 months now averages 3 bfpd on 12 timed cycles of the casing plunger. The chloride content of recovered water is still extremely high and indicates the continued “leak” from the zone of the casing leak. Current plans will continue to produce gas and “leak” fluid as well as production zone fluid until such time as it seems reasonable to attempt a successful repair of the casing leak. In the meantime, current gas sales rates and experienced expenses indicate that an effective solution to this well bore condition has been achieved with a casing plunger.

CONCLUSIONS

A typical “PAL” casing plunger application can be modified to replace a typical pump jack and rod pump installation to recover lost fluids after a casing leak repair. The critical modification seems to be in the location of the collar stop to utilize existing reservoir pressure to lift the plunger and accumulated fluid. As the static fluid level in the well bore is lowered, the fluid recovered per cycle declines and the trips required per day are lowered. The collar stop can then be lowered nearer the perforations to maximize the fluid recovered and increase the potential for gas sales. The cost of installation of the casing plunger is about 1/3 the cost of a typical pump jack installation. The daily cost of operations is comparable to that of a pump jack. Therefore, there will be times when the installation of a casing plunger to recover lost fluids will be practical and cost effective.

ACKNOWLEDGMENTS

Marlin Oil Corporation Inc. Oklahoma City, Oklahoma for their willingness to be innovative and patient during this modification in the typical application of casing plungers. Their management and field personnel were both competent and cooperative.

Celestine Gas Production

Natural Gas Production (MCF)

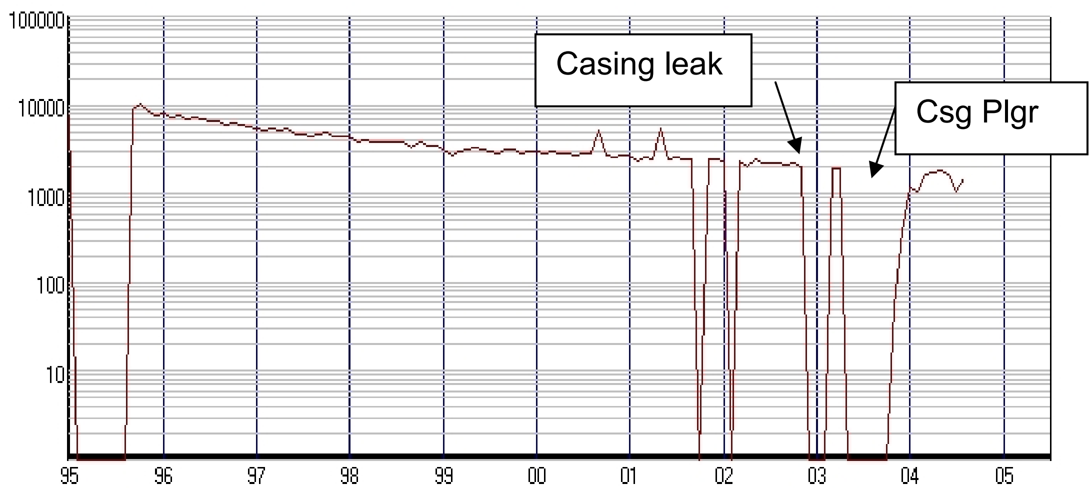

Figure 1 - Well production shows typical decline and steady production until casing leak in 2nd quarter of 2003. Casing repairs initiated and not totally successful. Subsequent attempts for 2nd squeeze were deemed inappropriate. Alternative solutions were pump jack and rod pump or casing plunger. Casing plunger installed in November 2003. Production, after several modifications to typical casing plunger application, was restored to comparable sales volumes prior to casing leak. Gas sales continue 18 months after casing leak "repaired".

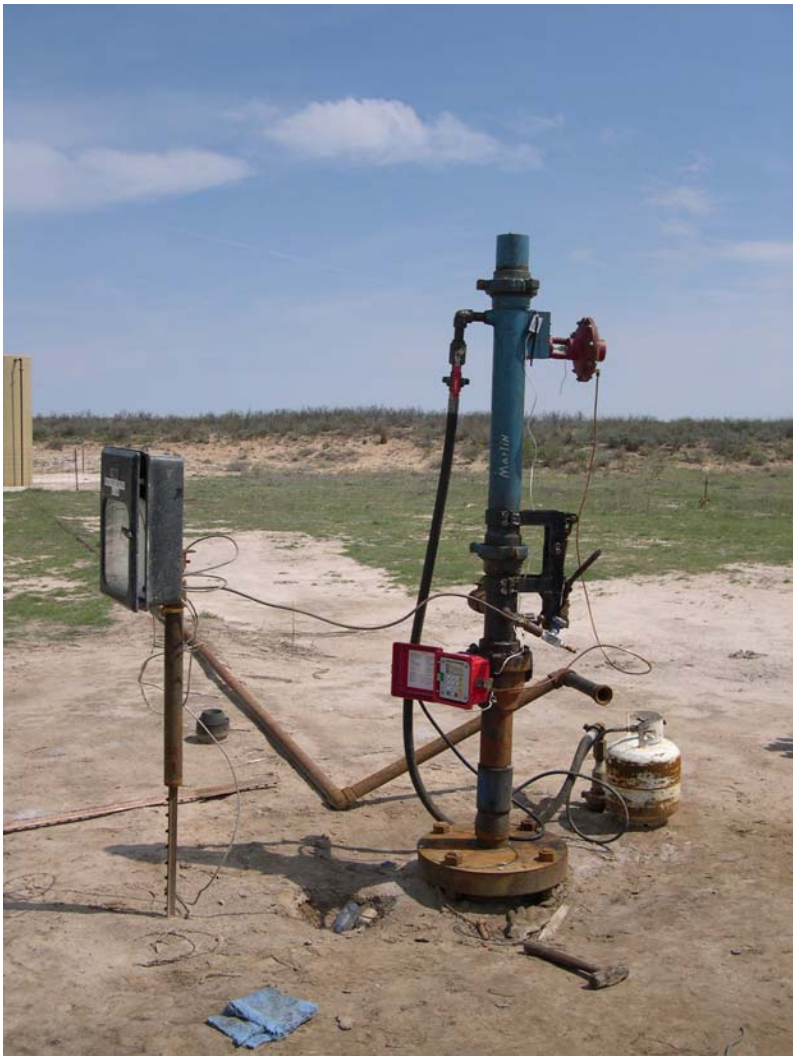

Figure 2 - Well head has been modified from typical 3000 # flange well head to 8 rd thread with full port ball valve installed as required for casing plunger application. Bottle gas can be used for clean, dry supply gas for controller timer. Surplus chart recorders can be used to record plunger cycles and trip times.

Figure 3 - Typical Flange Wellhead with Tubing Plunger Installation
Prior to Modification for Casing Plunger Application

Figure 4 - Typical Flange Wellhead “B” Section Being Removed
to Expose Top of Casing for Welding of Bell Nipple with 8 rd
Threads Looking Up

Figure 5 - Top of Casing Prepared to Weld 8 rd Thread Bell Nipple
for Full Port Ball Valve Required for Casing Plunger

Figure 6 - Bell Nipple with 8 rd Threads Welded Onto Top of Casing
Use of vent stack allows gas flow to be safely diverted away from weld site. Alternative flange adapters are available when company policy prohibits use of welding on well site.

Figure 7 - Casing has been modified for full port ball valve and ready for installation of casing plunger. Should the need arise, the ball valve can be removed and a standard threaded casing/tubing head installed for conventional casing-tubing production applications.

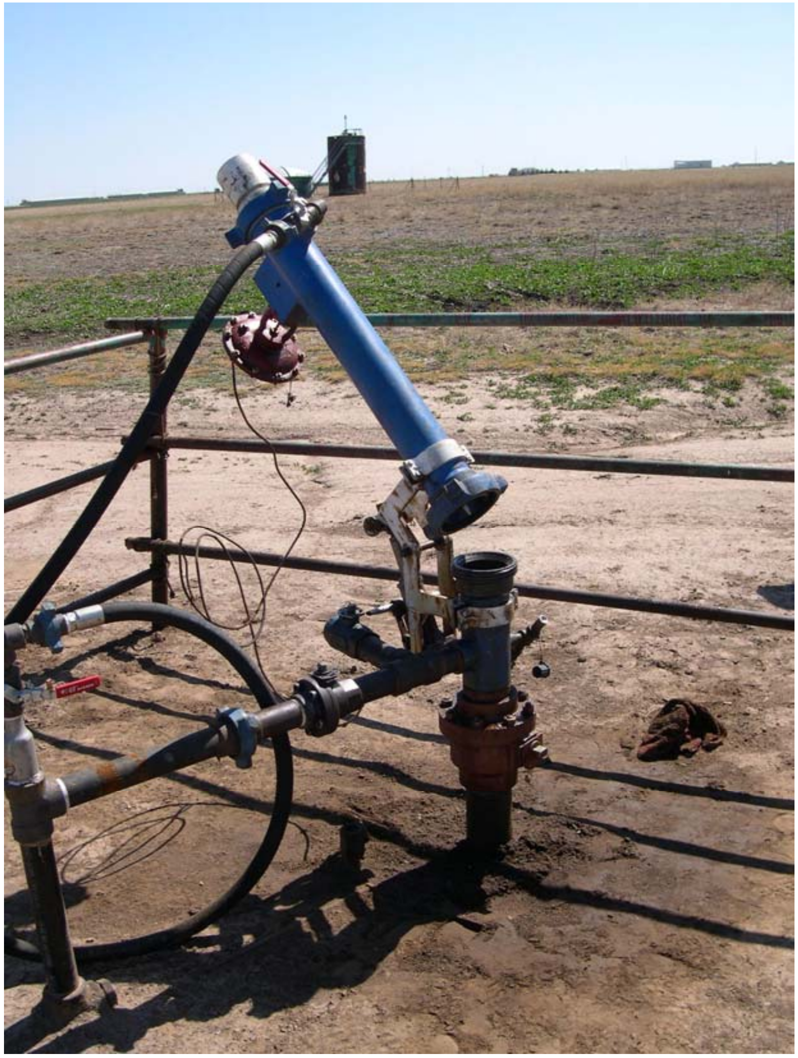

Figure 8 - Fully Assembled Casing Plunger Lubricator
Power assisted lift (Pat. Pend.) is helpful on 4 ½ inch casing plungers and essential on 5 ½ inch casing plungers.