UTILIZING NEW CASING PLUNGER DESIGN IN COMPLETIONS EQUIPPED WITH 4.50" OD CASING AND WITH MULTIPLE PERFORATIONS

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Introduction

Carnegie Production Company operates wells in the Appalachian Basin throughout the states of Pennsylvania and West Virginia. A typical well is completed with 4.5" OD casing in multiple zones with multiple sets of perforations between 3000' to 6000'. Liquid loading is a common problem in these wells due to insufficient flow rates to remove liquids. Liquid loading decreases production and occasionally will completely shut-off production. Frequent swabbing, rod pumps, siphon strings, tubing plungers are some methods used to remove these fluids. One cost effective method gaining increased use is a modified 4.5" nominal OD casing plunger utilizing a pressurized dome. This modified casing plunger eliminates the need for tubing, siphon strings, rods and downhole pumps. The modified casing plunger can remove liquids from a completion, be a solution to the liquid-loading dilemma, increase production, and extend the life of wells with very little investment. The modified casing plungers are designed primarily for wells that cannot operate, nor support the cost, of traditional pumping systems or frequent swabbing. The casing plungers are becoming an economic alternative to swabbing these lower volume, low pressure wells, particularly if these wells produce 1 to 10 barrels of liquid per day. A description of the modified casing plunger, a liquid unloading sequence, and field results from Carnegie are summarized in this paper.

Description Of Modified Casing Plunger System

A modified casing plunger system utilized by Carnegie consists of a plunger, a surface lubricator, and a conventional collar stop. Figure 1 is a schematic of the plunger. Physical properties of the subject casing plunger are:

Physical Dimensions: Weight 28 lbs. Length 36" Diameter 3.75" OD 1.75" OD Fishing neck
Setting Pressure Range of Dome: Minimum: 35 psi; Maximum: Not to exceed reservoir pressure.

The dome is nitrogen charged @ 60° F with a small amount of liquid in the dome above the seal for lubrication and to isolate the seal from the nitrogen. The internal valve is normally open once the dome is pressurized and has a 2" OD for flow. Two elastomer bell cups are the sealing elements that provide a pressure seal and allow a pressure differential across the plunger so it can travel upwards to the lubricator and unload liquids. A teflon spiral centralizer is on the lower body of the plunger and also acts as a liquid diffuser or shock absorber (reduces load on bell cups) when the plunger is traveling downward. The nose is equipped with a choke to control flow through the plunger and thus decrease the falling velocity of the plunger since the internal valve is open when traveling downward.

The lubricator is constructed from the same material as the casing with similar internal dimensions. See Figure 2. The lubricator has a bumper spring housed in a removable cap to allow for servicing of the plunger. Typically, a full opening valve, similar to a frac valve is installed between the casing and lubricator so the well can be shut-in during plunger servicing. Two flow outlets with an adjustable choke installed on the lower outlet to control gas surging is recommended.

Operation Of Modified Casing Plungers

The key difference between normal plungers and the modified casing plunger (MCP) is the pressurized dome of the MCP. The pressurized dome of the casing plunger senses a combined total pressure, composed of hydrostatic and surface FTP, above the plunger. Figure 1 is a schematic of the MCP and Figure 3 is a schematic of the Internal Assembly. The dome operated plunger opens and closes an internal valve or seat based on the total pressure exerted on the MCP.. The internal valve opens once the total pressures above the plunger decrease below the dome setting pressure. The dome pressure is set based on calculations that incorporate well performance, reservoir pressure, and optimum plunger trips. A brief summary of one unloading cycle of the MCP follows:

- MCP is setting on collar stop with internal valve or seat open. Gas and liquids are flowing primarily through the plunger, but natural gas velocity is insufficient to prevent liquid fall-back, thus liquid accumulates in the well and eventually above the plunger.
- Sufficient liquid accumulation above the plunger, combined with FTP, (combined total pressure) closes the valve.
- All gas and liquid flow is around the plunger. However, the bell cups expand, prevent flow, and create a pressure differential.
- The MCP begins traveling towards the surface once the upward force from the differential pressure exceeds the downward forces of the plunger weight and friction. Disregarding friction, a differential pressure of 2.1 psi yields a force of 28 pounds (the weight of the plunger in air).
- MCP reaches the flow lubricator and has successfully removed the hydrostatic liquid head accumulated above the MCP. Gas flow continues while the MCP is in the lubricator.
- As the total pressure above the MCP decreases, the internal valve of the MCP opens.
- The MCP begins traveling downward with the internal valve open and the well remains open to flow.
- Plunger fall velocity is reduced by a choke (which can be varied in size) in the nose of the MCP.
- The MCP travels downward until it reaches the collar stop or until the MCP senses a sufficient total pressure to close the internal valve and repeat the unloading process.

Comments on the above unloading example:

1. The internal valve remains open as the plunger begins to fall and thus allows flow through the MCP.
2. The well is not shut-in while the plunger falls to the collar stop.
3. The internal valve of the MCP closes once the total pressure is sufficient to close the internal valve. Thus, the MCP may not travel completely to the collar stop before beginning another unloading cycle. The MCP can unload a well through several unloading cycles without operator assistance and without traveling to the collar stop.
4. Time clocks or specialized surface regulators are not required.

Calculating The Dome Pressure Of The Modified Casing Plunger

Production information such as surface FTP during flow periods, reservoir pressure, liquid specific gravities, and surface operating constraints will assist in optimizing the dome setting pressure for the MCP. The dome setting pressure is the sum of FTP and the hydrostatic fluid load, in psi, above the plunger that one expects to unload. This total pressure should not exceed reservoir pressure otherwise the MCP internal valve will never close.

> Typically a liquid load of 1-2 bbls is utilized because of surface production and reservoir pressure constraints; 2 bbls in 9.5 ppf, 4.50" OD casing represents a liquid column of 123'±. For example, a 10 bbl load could be selected for the MCP to remove. However, 10 bbls of liquid arriving on the surface in a relatively brief period of time, yielding a high instantaneous production rate, may create problems for separators and compressors. Also, a 10 bbl head of 1.04 specific gravity liquid in 4.50" OD casing (9.5 ppf with a capacity of 1.62 bbls/100') yields a hydrostatic pressure of 278 psi. Allowing the well to build this volume of liquid may inhibit inflow performance and exceed reservoir pressure of some completions.

An example pressure calculation follows for 4.50" OD 9.5 ppf casing, a 2 bbl slug, liquid S.G = 1.05, and FTP = 20 psi:

Dome Pressure = 20 psi + [2 bbl/.0162bbl/ft * 0.433 psi/ft * 1.05] = 20 psi + [123' * 0.455 psi/ft] = 20+56 = 76 psi

For the above example, the recommended practice is to set the dome pressure at 76 psi @ 60° F and not at the downhole temperature or average well temperature. Perhaps this may introduce some error in the operation of the MCP, but at this time the MCP's are properly operating without compensating for downhole temperature.

Some error exists in calculating the hydrostatic pressure from the liquid slug. Calculation of the hydrostatic pressure of the liquid column is subjective because the exact composition of liquid (oil and water percentages) and the actual specific gravity of the gas-cut liquid slug are unknown. For example, if the S. G. in the example above is reduced to 0 .8 because of gas bubbling through the liquid slug consisting of oil & water the revised dome setting pressure is now: 20 psi + 43 psi = 63 psi or 13 psi less than originally calculated. As more MCP installations are implemented, improvements in the actual dome setting pressures may evolve. Thus far, field operations have steered improvements in the MCP towards the bell cups and surface lubricator.

Carnegie's Case Histories Of MCP Installations

A major problem for any casing plunger is operating in wells with multiple zones with multiple perforations. Carnegie has a large family of wells completed with multiple zones and 4.50" casing that required swabbing or some other type of remedial action to stay on-line. Carnegie investigated the possible application of the MCP to their completions. MCP's were installed by Carnegie in two multi-zone wells located on Cedar Creek, Dekalb District, Gilmer County, West Virginia Through field testing, it is becoming more evident that certain types of these multi-zone wells can utilize the MCP..

Davis-Swisher #1542

The first well, Davis-Swisher #1542, completed in 1995, has a production string of 4.5" casing with a TD of 4850'. The Benson formation produces from perforations 4733'-4742' with12 holes, the Balltown perforations from 3722'-4383' with 17 holes, and the Speechley perforations from 3251'-3374' with 17 holes. Wellhead pressure after a 72 hour shut-in is approximately 400 psig.

The shut-in pressure for the individual zones is not known, but based on offset wells, where single zones are completed, it is believed that none of the zones have a shut-in pressure less than 180 psig for 72 hours. The Benson formation normally has the highest shut-in pressure. For this area, when initially completed, the Benson's wellhead shut-in pressure is in the 1000 –1200 psig range.

Previously, after swabbing, gas production for well #1542 is in the 20-30 Mcfpd range. In a short period of time, production will decrease to the 12-15 Mcfpd range. Eventually the well will quit producing because of liquid loading. The well then has to be "soaped", "kicked off" or swabbed again to resume production. The well produces less than 2 bpd of oil and water, predominately oil, when swabbed daily.

The well was broached to 4700' and the MCP was installed with the collar stop set at 4642' during September, 1997. Since installing the plunger, gas and oil production has averaged 25 Mcfpd and 0.5 bopd. This represents an incremental production change of 13 Mcfpd and 0.5 bopd.

Whiting #1623

The second plunger was installed in the Whiting #1623. The production string is 4.5" casing with a TD of 5133'. The well was completed in the same zones as #1542. The perforated intervals are the Benson formation, 4695'-4700' with 16 holes, Balltown formation, 3933'-3953' with 10 holes, Speechley formation, 3605'-3693' with 12 holes. Like #1542, wellhead shut-in pressure after 72 hours is approximately 400 psig. This well also experiences the same fluid-loading problem.

Whiting #1623 produces 30 – 40 Mcfpd after swabbing. Fluid production was measured the same way as well #1542, by swabbing daily and found to be in the 1–5 bpd range, predominantly oil.

The well was broached to 4700' and the MCP installed with the collar stop set at 4535' during September, 1997 . Since installing the plunger, gas and oil production has averaged 31 Mcfpd and 1.5 bpd which is an increase of 5 Mcfpd and 1.5 bopd. Swabbing since installation of the MCP has been eliminated. Line pressure averaged 34 psig and back pressure on the well averaged 56 psig.

For both wells, wear on the plunger cups has been normal and have been changed every four to six weeks. The plunger is serviced in the field. A decline in production and the number of trips by the MCP usually indicate worn plunger cups. Travel frequency and casing smoothness/roughness/tight spots will determine the maintenance required on the cups.

Overall, incremental production volumes are not huge, but the incremental gas production percentages, 38% on the #1542 and 19% on the #1623, are significant. In addition, swabbing and soaping expenses have decreased for these two completion. The concept of successfully utilizing the MCP for multi-zone completions was proven with the two Carnegie installations.

Future Developments And Recommendations

In these two wells the liquid unloaded (recovered at surface) is predominately oil, bringing added revenue, but Carnegie is currently installing a casing plunger for brine water removal also. The well was completed very similar to wells #1542 and #1623 and suffers from similar liquid loading problems with the brine. This type of well is more common and future installations are mainly for wells with brine water build-up problems. Carnegie is considering 5 to 10 more wells for casing plungers in 1998. Maximum liquid removal rates are unknown, but should be comparable to other plunger systems.

Carnegie is also trying to study the concept of using one plunger for several wells. It is thought that perhaps a group of wells could be unloaded by moving the plunger from well to well at determined times before fluid loading significantly reduces production. This would apply to wells that meet the necessary plunger criteria and produce sufficient liquid to require regular swabbing. If this "plunger sharing concept" could be developed, one lease operator could operate the group of wells more efficiently, increasing production, eliminate swabbing costs and other associated operational costs. MCP's for 5.50" OD casing are also being considered.

Conclusions

In summary, the MCP's are continuing to work in these multi-zone wells. Gas and oil production has been constant and the need for swabbing has been eliminated. Thus, operating expenses are reduced. Reduced expenses and enhanced revenues will increase the return rate on these wells and definitely extend their economical limit. The MCP is an alternative artificial lift method to siphon strings, rod pumping, and conventional plunger lift systems.

When considering installing a casing plunger in a multi-zone completed well a good candidate appears to need the following conditions to operate properly: good casing integrity, be able to broach well through top perforations, complete zones with a limited shot density, have equivalent reservoir pressures between zones, and know approximately the deepest entry depth of gas production of sufficient volume and pressure to install the collar stop/plunger.

Advantages of the modified casing plunger over conventional plungers are:

- No tubulars are required, other than 4.50" OD casing.
- Surface control systems or regulators are not required to operate.
- Well does not need to be shut-in for the plunger to fall.
- Plunger can be moved from well to well.
- System installation investment is less than $10,000/completion.
- Reduce operating expenses and lease operator surveillance.
- Stabilize or increase production/revenues.
- Liquid slugs can vary in size depending on reservoir pressure, inflow performance, and operator preference.

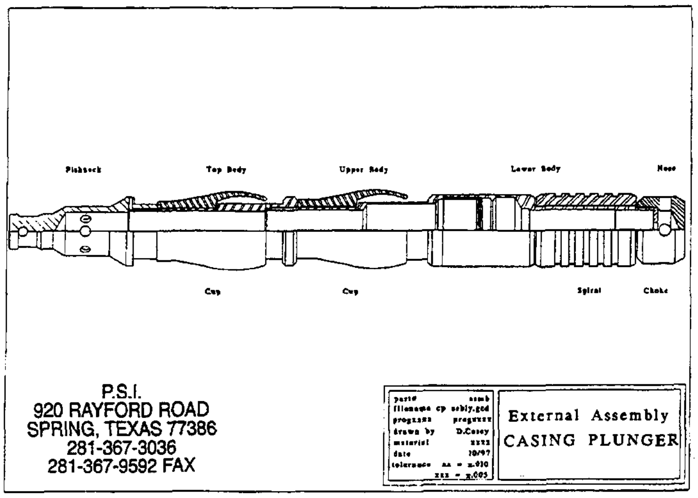

Figure 1

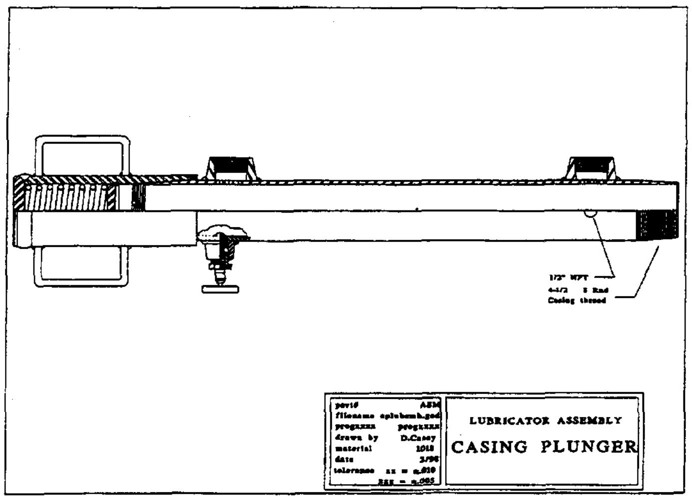

Figure 2

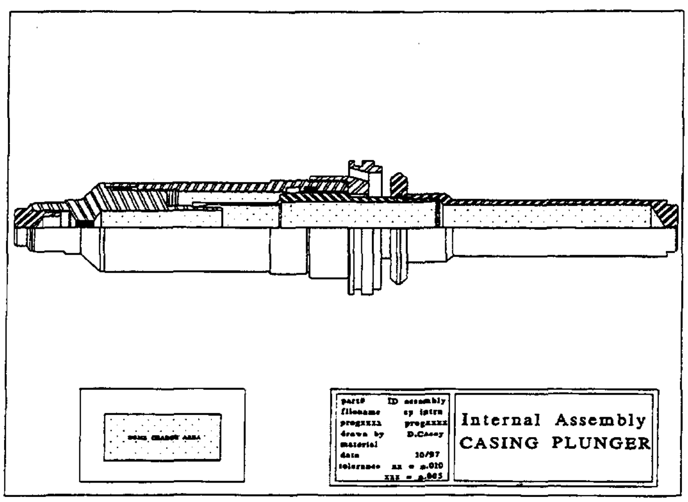

Figure 3