CASING GAS SEPARATOR – INITIAL INSTALLATION LEARNINGS AND DESIGN PROGRESSIONS

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ABSTRACT

A new technology was released last year with the goal of being safe, easy to run and attaining previously unachievable gas separation quality and quantity when compared to any other method available today. The new technology is a gas separator built into the casing call a Casing Gas Separator (CGS) and is run on the casing string immediately after a well has been drilled. CGS is run permanently into place on the casing with no alteration to the drilling program whatsoever.

The CGS can be run and set in multiple positions in the wellbore, but most commonly will be placed at kickoff point (KOP) or in a tangent further into the curve. The two covered in this paper were in each of these two favorable potions, one placed at KOP and the other into the tangent. In either position all successive well work occurs with absolutely no alteration to normal processes. This paper will discuss the pre-job planning with the Drilling Department, Completions Group, and Production Team. The paper will go into the actual execution of each installation and the outcomes of those installs. The lessons learned led to multiple design progressions and development of ancillary tools to be run in conjunction with the CGS.

Introduction

The CGS is a production tool that's installed in a well during the drilling operations. The CGS is easily picked up by the drilling rig after the bit has reached total depth (TD) the separator is run in hole as part of the casing string. The CGS is ran and set in a predefined position and cementing operations are pumped as per usual design. The cement wiper dart is not restricted in any way while passing through the CGS and lands at the toe of the casing as one would expect; the plug "bumps" like normal or in other words, a pressure increase indicating the plug has landed at the toe is seen.

Once the drilling rig is moved off location the stimulation equipment is moved in, rigged up, and their process begins. Frac plugs and perforating guns are dropped in the well and pumped down between the fracturing stages and pass through the CGS without issue. Each stage can be treated as designed without any ID, rate, or pressure limitation. Once all of the stages are completed either a coiled tubing unit or workover rig is mobilized and the mill out of the frac plugs begins.

After all plugs are milled out the well is either flowed back naturally for a period of time until it needs artificial lift (AL) or it is put on some form of artificial lift immediately (Figure 1).

This paper will discuss how the CGS can help production while still fitting into the normal drilling and operating procedures. It will then go into the first two CGS installs, lessons learned from the drilling, completions, and production phases. The paper will then go into the design changes between the first installation and the second installation as well as the progressions implemented immediately after and the complementary equipment created successively as a result of the learnings.

Operations

Drilling operations have become more and more efficient allowing us to drill faster than ever before. As we drill faster and our wellbores stay more competent we are able to complete the wells with less casing strings. There are multiple benefits that come from drilling with less casing strings when possible; less time spent casing, cementing, and the operations involved with both. Another reason to cut casing strings is simply the cost of adding an additional casing string. This has led many drilling departments to pursue "monobore" or "longstring" casing designs; where a singular sized casing string is run from TD to surface, typically 5-1/2" casing and now moving towards 4-1/2" in some cases.

The issue with these casing designs comes primarily later during the production phase when gas must be separated before being pumped away. The smaller ID of the monobore casings reduces the volume of gas that can be separated and effectively escape the wellbore without causing significant negative impacts on the most popular forms of AL.

The CGS allows for a much larger separation area to be utilized during the production phase with no alterations to a monobore casing design. The CGS is made up on the drilling rig floor, run to TD, and cemented in place. Once the well is ready to be stimulated the fracturing process can begin and once the well is done being stimulated the well can be drilled out. When the well begins to load and artificial lift needs to be implemented, a pump can be placed between the inlet and outlet of the CGS and largely increased separation capacity then utilized. No change must be made to standard operating procedures.

Although this sounds very straightforward there was much deliberation and discussion between the engineering disciplines on multiple occasions leading up to the final decision to run the very first CGS. There are many risks involved in all the activities we take part in while taking a well from spud to production, but the operations we do on a daily basis now days were at one time very scary if not at least very difficult, yet those tasks have now become common practice. It is only through the process of doing things once thought to be hard, risky, or very difficult that we begin to figure out how to further mitigate the perceived risks and progress what we do to a new level.

It is uncommon that each discipline of engineering knows in extremely detail the absolute needs, limitations, and simple wants of the others so we had to rely on an open forum of clear communication across the borders to ensure each had their concerned talked through and vetted completely to get a cohesive approval.

After all the potential risks had be mitigated to the teams' satisfaction through Q/C, testing, tight monitoring, and professional assembly protocol the very first well was then chosen to be our initial test case.

First CGS Installation

The first installation took place June 2018 with a CGS planned for landing at KOP. The CGS was a single-joint unit with handling subs on top and bottom resulting in an overall length of 49' long, a main outer body OD of 7", and the inner string was a 5.5" 17# design.

Dissolvable sleeves were used to cover the top discharge section as well as the bottom inlets. They were designed to be dissolved within two weeks after installation by the drilling rig. The CGS was assembled in Oklahoma City and shipped to location the day after final assembly. Three days following assembly the CGS was picked up and run in hole. A hydraulic skate was used to lift the tool from the ground to the floor and a casing running tool (CRT) was utilized to make up the tool once on the floor. The CGS was then run to TD and during the last 1,200' (6 hours) the CGS required rotation and reciprication, both of which are completely acceptable practices for the tool considering the rugged and robost build. At TD cement was pumped with no changes to the cement program and the cementing plug "bumped" at the calculated displacement. Thismade clear then no stalling of the plug was witness as it was pumped across the discharge section and it was later found too that no fouling of the discharge was experienced either.

After installation was complete the drilling rig moved off location and the stimulation crew rigged up. Plug and perforation operations began and were concluded days later without any issues or changes to their operations. Once the stimulation crew were done and rigged down, the millout began. After the millout concluded, a retreivable packer was set between the top discharge and bottom inlets of the CGS and fluid was successfully pumped down the backside ensuring the dissolvable sleeves had indeed dissolved and would not be obstructing flow. The retrievable packer was then removed and a wireline set packer was run in hole below the CGS to ensure proper landing depth could be correlated when the ESP was be run in hole. The ESP was then made up and run in hole with a swellable isolating mechnism made up modularly between the motor and the pump intake designed by that particular ESP service company. The ESP was run to depth, softly tagging the wireline set packer, and then picked up to proper set depth. After a quick test to ensure the ESP was functioning properly, the workover was rigged down and the ESP was then put into operation the well was turned to production.

Second CGS Installation

The second CGS installation took place in December 2018. With the first CGS in the ground and running properly there were a few adjustments that could be made between installations. Interestingly the operator apparently was made to feel comfortable enough after the fist successful installation they placed the order for the second CGS with only two days to finalize the build and get the tools to location.

A couple of changes were integrated into the quickly upcoming second test. The first was extending the separator into a double-stack unit for ease in properly locating the pump during installation and to generate a longer sump simultaneously. During the first installation extra steps were taken through additional time taken and money spent to ensure the ESP was placed exactly where it was desired to be. By extending the separator to two joints long it would allow for an easier spaceout without compromising the ease of the tool's installation and use. The new "double-stack" unit was made up totaling close to 80' long. The system was again built in Oklahoma City and immediately sent to location. It was then run in the hole three days later. The installation process was very similar to the first except the CGS would be placed into a 60 degree tangent in the curve. The CGS was picked up in two pieces, made up on the rig floor, and run in to TD without issue. The last 16 hours and several thousand feet of the trip in required heavy rotation, a glass disc was used on this well due to the extended reach lateral and calculated torque and drag. Later the frac operations began and concluded without issue, the same as on the first test well.

A second change was made between the first installation and the second - a new isolation tool was designed to replace the original version made up between the motor and the pump intake. This new unit allowed the ability to rid the process of setting the WL set packer for proper locating and integrated the function of locating into it's functions. This new ESP isolation tool being a one-piece design allows for larger motors (i.e. 456 vs. 375 slimline) with higher HP ratings, and easy adaption to multiple vendors ESP's, something the first version did not allow for.

Additional Design Improvements

Now with two progressive designs in the ground, in test, and verifying conclusively the tools work as advertised the desire to proceed with additional improvements was not going to be ignored. Seeing how smooth even the double-stacked unit slid into the well, through a curve no less, it was a natural progression to upsize the outer body section straddling the discharge slots up to a truly maximum allowable size of 7-5/8" which is still easily accommodated by 5.5" casing drilling programs. Due to the huge new separation ID area generated at the top of the tool, maximize separation capacity can now truly be achieved; a 7-5/8"x7.0"x5.5" CGS simulates for the pump that it is operating inside a huge 6.50" ID casing bore, an environment completely unimaginable within the typical 5.5" monobore.

Further additional effort has be put towards the design of a lower slotted-extension that can be run on the bottom of the CGS to allow for adequate flow to by-pass 400 series motor equipment inside a heavy-weight 5.5" 23# casing seen in some cases which would be heavily aided by the ability to far more safely and effectively run an ESP in such a tight condition.

Conclusions

The CGS has proven to be a very safe and easy to run package that will greatly increase gas separation in conventional well casing designs often by as much and ~2.0-3.61x that of a typical monobore casing design.

There are indeed no additional needs to alter or limit any drilling or completion practices regardless of the severity of very aggressive running and fracturing procedures.

The CGS has proven to need no additional procedural execution regarding annular isolation and flush to ensure proper tool communication as the dissolvable materials have performed as defined in our test wells thus far.

The need to develop a more user-friendly and flexible isolation and locating device was realized quickly and thus developed in-house and made rapidly available creating ample opportunity to run with essentially any brand ESP.

As additional test are completed the need to further evolve the products and ancillary offerings will continue to be cultivated to meet customer needs and more stringent requirements.

References

1. Ellithorp, B. and Snyder, D., “A Simple Method to Double Separation Capacity in New Wells,” presented at Southwest Petroleum Short Course, Lubbock, TX, May 24-25, 2017.
2. Ellithorp, B. and Snyder, D., “Evolution of Rod Pump Systems in Unconventional Wells Leading to Today’s Best Practice and Beyond,” presented at ALRDC Artificial Lift Strategies for Unconventional Wells Workshop, OKC, OK, February 7, 2018.

Nomenclature:
AL = Artificial Lift
TD = Total Depth
CRT = Casing Running Tool
WL = Wire Line
HP = Horsepower
ESP = Electric Submersible Pump
ID = Inner diameter
OD = Outer diameter

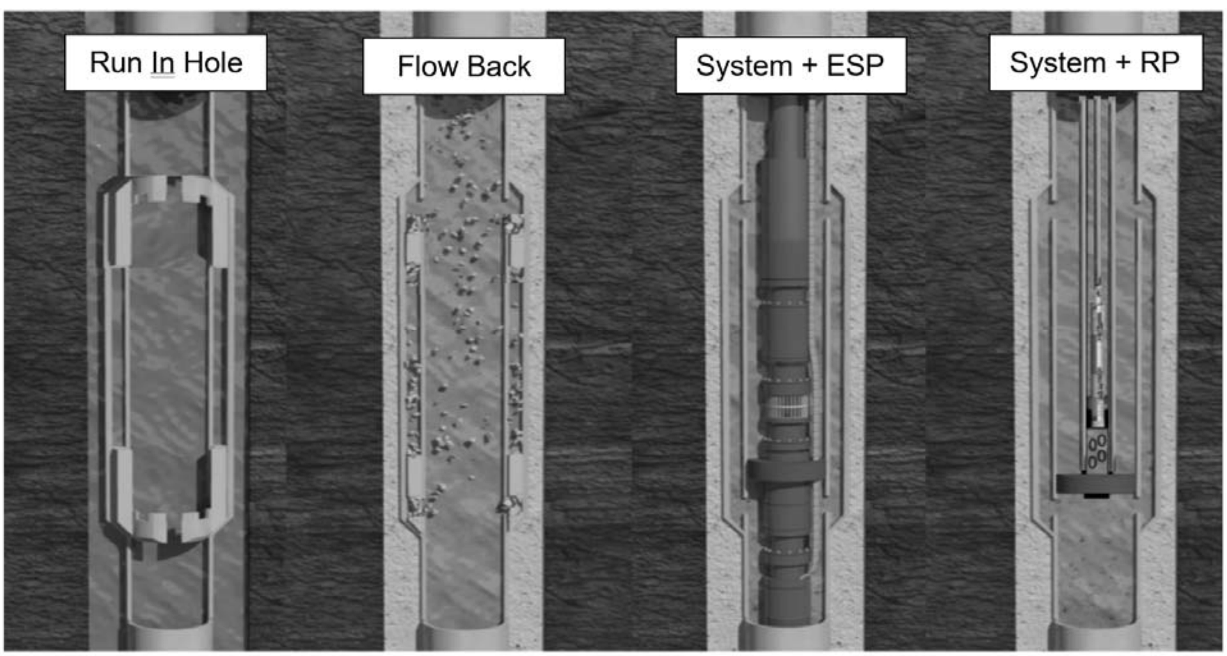

Figure 1 - Run in hole, degradable sleeves degrading, system producing with ESP, system producing with Rod Pum