ARTIFICIAL LIFT LEARNINGS IN THE BONE SPRING AND WOLFCAMP FORMATIONS OF THE WEST TEXAS DELAWARE BASIN

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ABSTRACT
In the West Texas Delaware Basin, at Anadarko, we are very early in the development of the Bone Spring and Wolfcamp formations. Our current artificial lift practice is to use gas lift or jet pump as intermediate lift, followed by rod pump. We implement these methods of artificial lift to produce high total fluid volumes and reduce downhole failures. This paper covers what we have learned so far and the questions that remain to be answered as we determine the most effective way to produce these wells.

INTRODUCTION

Our typical horizontal well is 11,000' TVD and requires initial artificial lift at total liquid rates ranging from 500 – 1,500 BLPD with GLR's ranging from 200 – 1,000 scf/bf. Our current practice is to go from free flow, to gas lift, and then to rod pump. This is mainly driven by two factors: high total liquid rates and downhole failures from scale and corrosion. In applications where we do not have economic access to injection gas (production separator or gas line is far from wellhead), we use jet pump as intermediate lift. We have had additional trials with ESP and plunger lift. In each section below, I will cover our issues, learnings, and remaining questions regarding gas lift, rod pump, jet pump, ESP, and plunger lift.

GAS LIFT

We implement gas lift as an intermediate lift between free flow and rod pump to produce the high total liquid volumes required, delay the large capital spend associated with rod pump, and avoid the cost/safety issues of working on a deep, high-pressure well for initial artificial lift installation. We are able to do this with gas lift because valves can be installed on initial completion. Through IPR/VLP and field tests, we find that our wells benefit from, and in some cases require, artificial lift at rates as high as 1,000+ BLPD. We also believe that gas lift is a good fit for our application as it is less sensitive to scale, corrosion, slugging, and high decline rates than other forms of artificial lift.

We are working to determine our optimal rate/pressure to begin injecting gas. IPR/VLP shows that our wells will benefit from gas lift before loading up, and we have estimates of the optimal BHFP and BLPD. We are conducting field tests to see how early is too early, and will compare that data with results from IPR/VLP analysis.

We do not currently have infrastructure for central-compression gas lift. Therefore, we are doing single-well wellhead compression, which leads to runtime being a big focus. We tend to see much better runtime from electric-driven compressors than gas-driven.

We are still new to gas lift and don't have too many lessons learned to share here. Our issues thus far have consisted of washed valves from sand or from bringing on the compressor too quickly, and thus we have trained all operators to follow the API kick-off procedure. We are also finding that it takes a long time to reach the bottom valve due to the high tubing pressure gradient. Through IPR/VLP, we do not see a huge benefit if we were to quickly reach the bottom valve, but we are currently evaluating the economics of larger compressors.

In our low GLR areas (<700 scf/bf), we find that continuous gas lift is absolutely needed. In our higher GLR areas (>700 scf/bf), so far, we are finding that intermittent gas lift is better for oil production. We plan on trialing plunger-assisted gas lift further down the road.

ROD PUMP

The majority of our field is currently on rod pump. At one point, we tried going straight from free flow to rod pump, but rod pump was unable to produce the required volumes. We found it difficult to consistently lift more than 600 BFPD with rods, as not all the wells would flump as expected, and we ended up deferring production. A big part of our production limit was also caused by our high clearance, and therefore high slippage, pumps. Thus, we added an intermediate lift.

We have yet to determine our optimal rate/pressure to switch from intermediate lift to rod pump. We have estimates of the optimal BHFP and rate from IPR/VLP, but no wells have been switched from intermediate lift to rod pump yet.

For our wells on rod pump, our main issue is downhole failures. This has been a big focus for our team, and we have been able to bring our failure rate down to 0.5 failures/well/yr from 1.1 failures/well/yr in late 2014. Historically, our biggest root causes of failures have been:

- Solids/scales (FeS, $CaCO_3$, $BaSO_4$, $CaSO_4$, etc.) causing pump friction and therefore rod buckling
- Corrosion (bacteria, under-deposit, CO_2, etc.) of our rods and tubing, often accelerated by rod wear

The design changes that we have made which we believe had the biggest impact on failure rate are:

- Improving our chemical program (scale/corrosion inhibitor, biocide, surfactant, etc.)
- Installing pumps that reduce friction / rod buckling with greater solid handling capacity (higher clearance, grooved plunger, pull tube, guided stabilizer, etc.)
- Running internally lined or coated tubing and/or rod guides to protect from rod-on-tubing wear
- Using rods (grade KD) that are less sensitive to corrosion but still adequate for our loads
- Installing and maintaining rod rotators

Due to our low GLR's and high fluid levels (so far), we do not have major gas separation issues. We are running 4.5" line pipe mud anchors, which are adequate at our pumping rates, where our casing is big enough. We run packer-type separators in smaller casing.

JET PUMP

We implement jet pump as intermediate lift when the wellhead is too far from the gas source (separator or gas line) for injection gas to be economically used for gas lift. Jet pump is capable of lifting the high total liquid volumes required for our wells. Other benefits are that PD pumps typically have better runtime than compressors (for gas lift), chemical treatment of the power fluid allows for the entire wellbore above the packer to be proactively treated, the tubing-conveyed portion of the BHA can be installed on initial completion, and a failure of the downhole pump/nozzle does not require pulling tubing. The downhole pump/nozzle can be circulated out.

Our biggest lesson learned for jet pump is that great attention needs to be paid to the chemical program, especially considering the potential bacteria issues involved with power water. On the pump suction, we are treating our power water with biocide, scale inhibitor, and corrosion inhibitor. We also believe that it is important to have a closed-loop system to prevent oxygen corrosion. Further, we believe it is important to pull power fluid off a separator/knockout rather than a tank, assuming adequate retention time, so that the fluid continues moving and does now allow for the growth of a bug population (power water) or paraffin (power oil).

We also strongly believe that working closely with the operators and having an open-minded field staff was instrumental in our success with jet pump.

ESP

ESP was our intermediate lift between free flow and rod pump in our original practice. The economics of running ESP's were not very favorable due to the downhole failures. The main root causes of the failures were electrical issues, flumping, solids/scales, and high decline rate. We are no longer running ESP's.

PLUNGER LIFT

We did a small trial with plunger lift as a gap-fill between free flow and other lift on a few wells where we did not have many other options; as we did not have power to location and we were pending results from gas lift and jet pump. We decided not to install any more plunger lift after this trial because gas lift and jet pump were better economic options in our situation. We have a very low GLR, but thought that our high BHP may help run the plunger.

In this trial, we confirmed what our IPR/VLP predicted, in that these wells greatly benefit from the drawdown created by gas lift or jet pump, and plunger lift was deferring production. Plunger lift also lacked the capability to kick the well off when it loads up after upset conditions on surface, which is unfortunately a big part of our reality. Last, as an additional trial, we removed the plungers but continued intermitting. The wells lost little production, which implies that simply intermitting the well might have been a more economic option.

CONCLUSION

We are using gas lift, jet pump, and rod pump as means of artificial lift. We believe that these artificial lift methods are best suited for our application. Our main challenges are lifting high total fluid rates and dealing with downhole failures from solids and corrosion.

We have learned the following about artificial lift on Bone Spring & Wolfcamp wells in the West Texas Delaware Basin:

- An initial artificial lift method that is capable of producing 1,000+ BFPD is needed.
- An initial artificial lift method that can aggressively drawdown the well and remove the back-pressure created by our heavy liquid column is ideal.
- An initial artificial lift method that can be implemented before load up and avoids cost/safety issues of working on a deep, high-pressure well is ideal.
- Artificial lift methods with reduced exposure to downhole failures or reduce costs involved with downhole failures are ideal.
- Proactive chemical treatment and other considerations for solid/corrosion handling are very important in artificial lift designs.
- Any artificial lift method must add energy to the system and be capable of kicking the well off when it loads up following unexpected upset conditions on surface, which are part of reality.

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