

IMPROVE HORIZONTAL ROD PUMP OPERATIONS UTILIZING ISOLATED TAILPIPE

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ABSTRACT

There is a growing awareness in the oilfield of the problems generated due to horizontal wells' long lateral lengths, undulation fluid and gas trapping capabilities, inconsistent and aggressive unloading behaviors, and limitations on historically and widely applied separation methods. Due to these impacting factors, horizontal rod pumped wells must address the resultant production behaviors as well as operational issues that can be worsened by poor application of old and non-optimal downhole separation and poor pump placement practices. It has now been proven in a multitude of applications and formations across the US that the use of a safely and correctly placed isolated tailpipe used in series with a diverter style of separator can help alleviate challenging production issues in horizontal rod pumped wells, resulting in substantially increased production output as well as reduced failures and lower operational costs.

Introduction

With a growing number of aging horizontal wells on production in basins all across the U.S. there has been an increasing count of wells transitioning from free-flowing onto some form of artificial lift for many years now. Each formation tends to produce with such volumetric characteristics and from such depths as to help dictate the most correct selection of that chosen form of artificial lift and sometimes even require a progression of lift types.

As has been the case for decades now, the final lift deployed in many of those wells happens to be still be rod pump. This may likely never change presuming no better option comes along. Rod pumped wells have historically been capable of being produced at lower sustainable bottom-hole pressure, with lower operating costs, they are typically very reliable and easily serviced, and it is a method many are familiar and comfortable with to boot.

Unfortunately, though, when our tried & true rod pump designs, namely separation, has been applied to the aforementioned horizontal wells it is quite common to witness extenuating complications with adequate gas separation quality and consistency becoming a more prevalent concern.

Loading and Slugging in Various Positions in the Wellbore

Reaching a better understanding as to why wells load and unload the way they do is much easier said than done. It has been even harder to figure out the best way to resolve the problems generated from such production characteristics.

When a well is drilled, regardless of how much effort is demonstrated by the drilling staff to maintain a tight window and drilling target, there are still many sinuous undulations, or up and down wavy movements, all along the lateral's vertical section. Some of this movement and resultant hills and troughs are certainly not purposely put there and it would be advantageous to avoid such movements all together, but that is simply not a reality as rate of penetration (ROP) keeps climbing as well as the overall lateral lengths have substantially increased in most areas where new wells are being drilled. A consequence of today's impressive ROPs is very typically a natural tendency for the bit to "walk" or follow the path of least resistance while cutting new formation. This causes the bit to drift essentially in any direction with little to no indication ahead of time as to what is about to happen. This frequently results in aggressive geo-steering with overzealous corrections being made and all the while making all that new hole and penetrating onward, thus the resultant hills and valleys that are common in our horizontal wells' laterals.

To make matters worse, the undulations being generally bad for a nice smooth transition of fluid and gas flow out of the lateral are essentially unavoidable. The slugging behavior can be suppressed with excellent geo-steering, good seismic data, offset well geological data, etc., but in the end it will never be

fully avoidable and generally far from anyone's mind, other than the production staffs', while the well is being drilled and completed.

Even if it was a topical issue for the team prior to and during the drilling process, the minimal amount of sinuous movement necessary to create a "trap" of fluids is generated by surprisingly the very smallest of up and down hill movement, e.g. <0.1 deg of inclination change when running along the lateral section. This tiny amount of dip change is sufficient to create a pooling or collection area for fluids and will inevitably result in a build-up and release of fluid and gas slugs for the duration of the wells producible life. Again, to make matters worse, this slugging behavior can in many wells become worse or certainly much more evident as the wells age and tend to "lateral load" more completely and there is such a low overall gas production rate and pressure associated with the well at that point the traps are simply that much harder to overcome and the slugging tendencies from trough to trough can become harder to avoid and deal with over time.

While on production those slugs will be delivered to the heel of the curve in wells that fall into the category of up-dip (heel of curve lower than the toe of the lateral) all the way down to flat (~90 degree) laterals. The fluids and gas then have the duty of removing themselves from the base of the curve and this is often an impossible task as the velocity profile required for adequate vertical lift to either flow naturally out of the well or to be delivered to a pump set somewhere uphole is simply non-existent.

Downdip wells, where the heel of the curve is higher than the toe, tend to produce with a different behavior as they are technically always lateral loaded to a good degree, thus those wells are not generally a great comparison here. (Reference **Figure. 1** for a simple visual review of 4 general lateral descriptions.)

Coming to Terms with the Natural Collection and Slugging Out of the Curved Section

As previously noted, when the fluids produced out of the lateral make their way to a primary collection point at the heel, or base of the curve, they are often stymied from proper removal for a couple of reasons.

One scenario is that the total volume of fluids capable of being flowed out of the lateral is incapable of being fully removed from that section of the well in short order and, although there may be what is considered a high volume of gas also being produced from the well over a 24 hour period of time, when looking at it on a more instantaneous level, the minimum gas volume flowing around the base and up through the curve as well as up the entire vertical portion of the wellbore, whether inside open casing or up the tubing ID, may not always be sufficient to take up, away, and out of the well all of that continuously delivered and collected fluids, thus the fluids will tend to fall backwards down the well and re-collect again from the base of the curve and progressively up into the vertical portion of the wellbore. This could be considered the conventional form of liquid loading and of course is directly related to the cross-sectional flow area of the casing. With an aggressive enough overall gas production rate this will be suppressed to a high degree and although fluids may collect at the base of the curve the gas flow is resilient enough in nature to actively and regularly make that turn from out of the lateral and up the wellbore.

This takes us to a second scenario where the collected fluids are stymied from active removal and this one is more relatable to those trying to artificially lift a well, especially rod pumped wells. This inconsistency in the wells ability to relieve itself of the gas which is essentially blowing through and around the fluid collection area in the curve steadily gets worse and worse as horizontal wells age and deplete. The nature by which the fluids have always wanted to preferentially collect in the "trough" of the curve never goes away and, unfortunately, the ability to sweep gas with consistency through this section and carry those fluids uphole is, shall we say, impossible considering the superficial velocity of the gas is not nearly high enough to truly lift those fluids completely from the wellbore or in other words it is well below critical rate.

Presuming this to be the situation all horizontal rod pumped wells will eventually be fighting we must get a better understanding of how gas interacts with, or rather travels through, the collected fluids in the well from above the pump intake all the way down to the base of the curve, as well as out in the lateral since all of these unique situations combine to yield very tough conditions for us to resolve with high frequency and severity of gas slugging, churning, turbulent mixing, build up and flow off, etc. This is an inevitable scenario each horizontal rod pump well will have to deal with unless the bottom hole assembly is adequately altered to manipulate the multi-phase flow in such a way as to substantially alleviate or suppress these very negative behaviors which make pumping operations very difficult.

Alter Your Thinking About Liquid Loaded Behaviors in Horizontal Wells

Let's think about what state most horizontal rod pump wells are in during normal operations and, more particularly, what is actually happening as the essentially stagnant fluid level is being continuously or maybe intermittently permeated with produced gas from the lateral.

A normal rod pump BHA utilizing a poor-boy gas separator is commonly located immediately at kickoff point in a horizontal well. That would leave the casing fully open below the MA and down to the lateral in a normal wellbore. It is commonly acceptable to presume as long as a fair volume of gas is being produced from the well that the gas void fraction (GVF) in the open casing portion of the well, namely the more vertical portion, would be filled approximately with 50% gas and 50% liquids. This can vary a bit with total gas production volume, casing ID, different bottom-hole pressure, as well as varying fluid properties, but that is a fair generality.

This is the case we will consider for this discussion and I will designate as "partially liquid loaded." If the well was "fully loaded" there would be no gas production and there would be 0% GVF in the static fluid column and if the well was "fully unloaded" there would be no measurable gaseous fluid level at all. Functioning in a partially loaded state is what virtually all horizontal rod pumped wells operate within. There is not enough gas to fully carry all fluids out of the well, obviously, or you wouldn't be on rod in the first place (let's ignore option to "flump" for this discussion). Yet on the other hand, there is more than enough gas being produced to create a very gaseous column of fluid strung up the well between the casing ID and the tubing OD and it is released around the base of the curve and blows through the fluid column with inconsistency and various instantaneous rates, just as was previously mentioned in this paper. This can be quite difficult for your typical rod pump separation design to handle.

Thinking back to the fact that the casing flow area cross-section has a direct correlation to GVF it would make sense to strategically alter the flow path for the multi-phase solution to be smaller, yet not restrictive, in an effort further improve flow dynamics and concurrently lower attainable pumping bottom-hole pressure (PBHP). The deployment of an isolated tailpipe consisting of a sized macaroni strings or thermoplastic lined (TPL) tubing along with a backside flow isolation tool located uphole near kickoff point coupled with the proper end of tubing (EOT) placement selection will significantly alter a horizontal well's ability to alleviate itself of the collected fluids in the trough of the curve. (Reference **Figure. 2** for a visual of isolated tailpipe in RP system.)

This is impactful as there is a significant alteration to the minimum critical velocity required to lift fluids to a pump located uphole, but even more importantly in wells that are subcritical, you still stand to gain significant flow improvement and a reduction in backpressure on the formation because even though the gas is not necessarily carrying fluids uphole, as in a true flowing condition, the massive reduction in flow path cross-section alters the GVF inside the sized tailpipe so much so it is common to witness as much as 50-75% reduction in the combined fluid gradient along the entire TVD run within that tailpipe. In other words, where you may have a 800' TVD path from the SN to landing of the EOT near the base of the curve and a gaseous combined fluid gradient hovers around 0.28-0.33 psi/ft within open casings, the same TVD path traversed with a smaller sized and isolated tailpipe could yield around 0.08-0.12 psi/ft active gradient. The application of isolated tailpipe in this well could yield as much as +175 psi reduction in pumping bottom-hole pressure. That is a great thing for a couple of reasons that will be explained next.

Positive Effects Only Attainable Through Isolated Tailpipe

One great effect of the isolated tailpipe setup is the obvious which would be an incremental production gain both in fluids, hopefully mostly oil, and gas. This potential result is easily modeled in many nodal softwares and is handled quite well in the more simple softwares so as long as you are not planning to simulate a well with more rigorous reservoir modeling requirements. The predicted incremental gain is only a small driver in many of the decisions to run such a design into a horizontal rod pumped well. (Reference **Figure. 3** for a visual a horizontal well IPR and the effect of various sizes of isolated tailpipe in a RP system.)

A more prevalent driver in the decision to run isolated tailpipe in a horizontal is the ability to smooth out the aggressive slugging and flow-off behavior of wells with highly sinuous and porpoised laterals. We discussed earlier the effects of laterals with this geometry and the heavy slugging tendencies of such wells cannot be stopped with improved drilling techniques while constructing the laterals, but we can do a much more proficient job of evacuating the sporadically delivered fluids that desire to accumulate in the trough of the curve. Isolated tailpipe helps reduce, or given the right fluid and gas volumes and placement can stop, the accumulation from occurring during active pumping operations.

So to recap and link a few items, the reduction or elimination of the heavy collection of fluids in the trough of the curve helps stop slugging at and around the curve. Above the trough, the lighter gradient in the isolated tailpipe and reduced critical velocity also reduces slugging tendencies. Finally, those two elements compounded then allow for a third major driver in this equation of impacting elements to become evident.

The third component that we have found to be virtually impossible to predict the full benefit with accuracy, yet appears to have potentially the biggest impact on positive well performance is this: the damping out and suppression of slugging to the point where a more consistent and manageable fluid/gas mix is being produced uphole to the pump allows for, with proper automation control, pumping units to run all day around the clock with no or very few shutdown events. This is of course a good thing for the rod pump equipment as frequently the best pumps like to run without interruption, but the related benefit is even more important and that is there is no opportunity for, upon cycling, the well to load on itself and have the gasified fluid level strung up and down the hole to liberate itself of the entrained gas, thus allowing fluids to fall down the hole and backwash through the curve and reinvading the effectively deliquified perf'd intervals in the front portion of the lateral. This would then reload the collection trough the curve and keep the farther extents of the lateral from contributing again until the well was restarted and running for long enough to clean itself up, yet again, in hopes that another shutdown cycle event was not coming around too quickly or this would happen all over again. Gaining longer and sustained contribution from further out in the lateral is believed to be the factor that creates the results where we see a large positive deviation from the anticipated outflow as a function of drawdown improvement on the IPR; its better contribution from a historically loaded or semi-loaded portion of the well that has just been waiting to be freed up to produce.

Conclusion

This paper describes the use of small ID, isolated tailpipe that can be run into the well near the bottom of the horizontal's curved section and, when placed at the right inclination and sized correctly, can generate a chain of events that allows for sluggish well production behaviors to be suppressed, additional fluids to be pumped, lower PBHP's to be attained, and an overall much improved pumping operation feasible.

It is likely impossible we will ever be able to drill horizontal wells' laterals straight enough to eliminate the collecting of fluids in low troughs and the resultant slug off behavior throughout those laterals.

In flat and up-dip wells the heavy collection of fluids at the base of the curve produced out of the lateral exacerbates the sluggish production behaviors so long as there is no means present for a more effective take away of those collected fluids, such as a correctly sized and placed isolated tailpipe.

Isolated tailpipe can reduce the average gradient of the combined produced fluids below a pump set above the curve by as much as 50-75% based on variable factors. This leads to a significant reduction in PBHP often in the range of 150-175 psi.

The proper application of isolated tailpipe can set off a chain reaction of events that greatly improves day-in and day-out pumping operation efficiencies and the ability to clean up the collected fluids throughout the wellbore to such a degree large and sustained incremental production gains are possible.

References

1. <http://www.industrimigas.com/2013/06/production-logging-of-multiphase-flow.html> (2013)
2. <http://2.bp.blogspot.com/-ItHlyQaEm0o/Ucc6duhmiFI/AAAAAAAAAGM/CpwjwXsLBwg/s1600/horizontal+well.png> (2013)

Nomenclature:

ROP = Rate of penetration

ID = Inner diameter

OD = Outer diameter

GVF = Gas void fraction

BHA = Bottom hole assembly

MA = Mud anchor

TPL = Thermo plastic liner

EOT = End of tubing

PBHP = Pumping bottom hole pressure

Figure 1 – Four Different Types of Lateral Configurations in Horizontal Wells

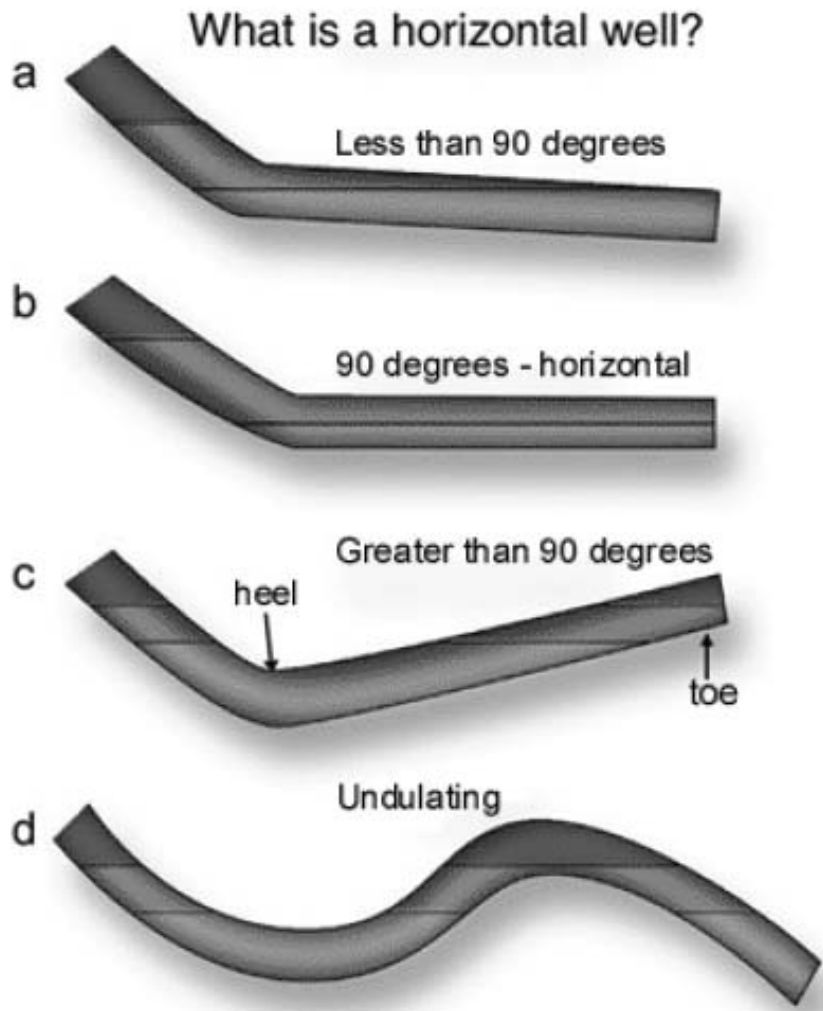


Figure 2 – Isolated Tailpipe Configuration for Horizontal Rod Pumped Wells

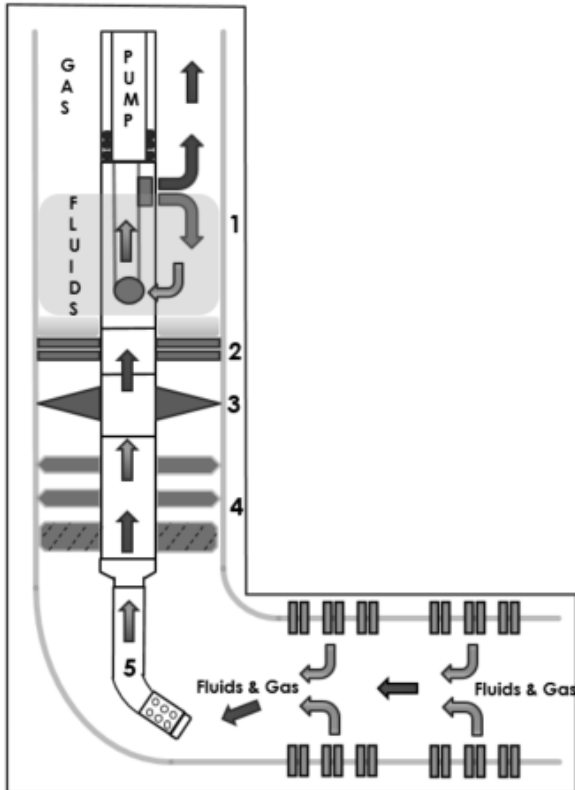


Figure 3 – Horizontal Well IPR Illustrating Effects on Outflow Potential Due to Different Sizes of Isolated Tailpipe

