

ENHANCING DOWNHOLE GAS AND SOLIDS SEPARATION AND LOWERING OPERATIONAL RISK BY TAKING ADVANTAGE OF MULTI-PHASE FLOW REVERSALS

Jeff Saponja, Rob Hari, Sean David, Justen Brignac, and Dayley Jaszan, Oilify
Corbin Coyes and Brandon VanHuss, Q2 Artificial Lift Services
Anand Nagoo, Nagoo & Associates LLC
Brandon Penner, Calyx Energy III LLC

INTRODUCTION

The economic benefit of greatly improving the efficiency and reliability of sucker rod pumping is simply massive. No other artificial lift method can achieve the level production drawdown or low bottomhole producing pressure per unit cost as sucker rod pumping. A Production Engineer'sⁱ ultimate goal is maximization of reserve recoveries at the lowest operating expense (OPEX) per barrel of oil produced; producing a well using a sucker rod pump, with reliability and at near atmospheric bottom hole pressure, can achieve that goal.

In an ideal situation, rod pumping is industry proven as cost-effective and reliable. Sucker Rod pumps are highly efficient over a broad operating envelope of production rates and depths. They are compatible with multiple completions and slimhole wells. Sucker rod pumps are mechanically simple; therefore, tend to be easier for operators to operate close to optimum conditions. There are some drawbacks and limitations with rod pumping. They are challenged by gas interference, solids production, paraffin and scale; however, corrosion, paraffin and scale treatments are available. Sucker rod pumping is known to be less efficient when the pump is placed in the deviated section of the wellbore. Disadvantages aside, sucker rod pumping continues to be the first choice for many operators.ⁱⁱ

A sucker rod pump performs optimally with consistent gas free and solids free liquid – downhole separation of gas and solids is required. A downhole separator is therefore a critical component in a sucker rod pumping system for achieving consistent pump fillage for long term reliability and high pump fillage for maximizing production rate.

Downhole separation of gas and solids for sucker rod pumping is and always will be a significant challenge, particularly in horizontal wells. It is well understood that one of the underlying and fundamental separation capacity technical limitation is from commonly used casing sizes, such as 5.5" by 20 pounds per foot, which physically limit the cross-sectional area for separation. A second technical limitation is that liquid and gas flows emanating from a horizontal wellbore are not steady state – they are highly inconsistent and sluggish. Inconsistent flow conditions mean separators must not be designed for steady state conditions, rather they must be designed to efficiently operate under very broad, transient, liquid and gas flow rates and gas volume fraction conditions. All of these technical limitations have been compounded with the industry's trend of longer length, higher rate with higher decline, higher gas liquid ratio, horizontal wells.

It is less understood that separation capacity has also been limited by the location and orientation of a separator's intake, the shape of the separator's separation conduit and by a common mechanical design practice of a concentric or centralized pump intake dip tube and mandrel. For example, the standard and common design practice of a concentric annular shaped conduit for separation has limited separation capacity to the rate at which gas bubbles can rise upwards in countercurrent downward liquid flow.

Improving downhole separation without undesirably increasing operational risk and cost has been difficult. For example, a separator design that requires a packer or annular seal, such as a cup, is inherently more

operationally risky from an installation and retrieval perspective. Further, a separator design that imposes pressure drops and/or increases flow turbulence face the risks of scale deposition, erosion, and reduced separation capacity due to turbulence worsening of the amount of entrained gas in the liquid and foam generation. Separators designed to separate in multiple stages become excessively costly and operationally riskier with excessive tool lengths.

A significant advancement in downhole separation capacity with lower operational risk has been achieved by realizing there was an opportunity to intentionally take advantage of transient multiphase flow conditions where liquids and solids flow reversals exist – liquids frequently fall backwards as they move up a wellbore in the slug and churn flow regimes. By re-orienting a separator's intake facing upwards and optimally shaping the separation region's flow conduit to maximize the rate of flow reversals, liquid falling backwards could more easily be collected for substantially improving downhole separation efficiency.

This paper describes the successful design process and results of the field implementation of an enhanced downhole separator, called the WhaleShark™, that intentionally takes advantage of multiphase flow reversals and eccentric flow paths. Flow loop testing results and comprehensive analytical transient multiphase flow simulation demonstrated the opportunity for greatly improving downhole separation. A set of case studies, in multiple basins, reviews the field installations and presents the results of improved downhole separation performance, lowered operational risks, lowered Opex and increased production – for sucker rod and electrical submersible pumping (ESP's).

INDUSTRY STANDARD DOWNHOLE SEPARATORS: POOR-BOY STYLE AND PACKER-STYLE

There are primarily two forms of industry standard separators:

1. Poor-Boy Style packerless
2. Packer-Style

Both separators apply the same gas separation gravity-based principle of counter-current upward gas bubble rise velocity versus liquid downward velocity; gas bubble rise velocity must be greater than the downward liquid velocity for them to operate. In other words, they are governed by the rate at which gas bubbles can rise in the downward moving liquid.

Poor-Boy separators are packerless downhole separators, whereas Packer-Style separators use an annular seal in the form of a packer or a cup type seal. Figure 1 illustrates Poor-Boy and Packer-Style separator flow paths and typical mechanical design configurations.

Poor-Boy separators are commonly based on the same design principles of a concentric pump intake dip tube inside a tubular body mandrel with side entry slot/port intakes and gas vents to the well's casing annulus. Gas separation occurs in an inner annular cross-sectional area formed inside the separator as shown as A1 in Figure 1. Some variants include a poor-boy separator with a vortexed flow accessory for assisting separation of gas and/or assisting separation of solids for settling solids into mud joints. They are generally lower cost than a Packer-Style separator.

Packer-Style Separators require a packer or cup type seals (with a tubing anchor catcher) for directing all the multiphase fluid flow through the separator and for discharging at the top of separator into the casing annulus above the packer/seal. A pump intake dip tube port is positioned just above the packer/seal to draw in degassed liquid from the casing annulus. Gas separation occurs in the casing annulus formed with the well's casing adjacent to the separator's outer mandrel as is shown as A2 in Figure 1.

This separation annulus, shown as A2 in Figure 1, can be larger in cross-sectional area as compared to a Poor-Boy separator's A1 separation annulus; this larger cross-sectional area can improve separation capacity and efficiency simply since there is more cross-sectional area (i.e., liquids travel downward at slower velocities). The fluid residence time in this separation annulus, as the liquid moves downwards to the pump intake, can also be beneficial for separation of gas if the volume is larger than one pump stroke.

A major operational risk and downside of a Packer-Style separator is that solids can settle on top of the packer or cup seals and cause significant workover cost/risk (i.e., retrieval risks are high). To control this risk, a solids separation accessory is commonly attached below the packer/seal and upstream of the gas separator.

RESEARCH REVEALED OPPORTUNITIES TO IMPROVE DOWNHOLE SEPARATION

The artificial lift community of practice has been seeking improvements in downhole separation for gas and solids, especially due to the increased production complexities associated with multistage fraced horizontal wells.

For the sucker rod pumps, the common improvement wish list has included:

- lower operational risk – avoid packers or cup seals; want packerless; avoid scaling in hole risks,
- higher average pump fillage – for maximization of production,
- more consistent pump fillage – for protection the pump and rods and to maximize reliability,
- broader operating window – as production from a well matures over time, minimizing the number of pump/separator re-configurations reduces lifecycle operating costs,
- more solids separation capacity – ability to handle broad flow rate conditions and solids sizes/concentrations, with a low-risk sump retention and retrievability (i.e., commonly called mud joints that are connected onto the base of the separator).

The primary challenges that have been faced for achieving the improvement wish list include:

- a. small casing cross-sectional areas and annular spacing trade offs – the capital cost associated with increasing wellbore diameter is the principle barrier to increasing the cross sectional flow area, thus existing separators, which are governed by gravity-based counter-current gas bubble rise velocity versus downward liquid flows, are therefore physically constrained / limited by this physics principle,
- b. inconsistent and sluggish flows from the horizontal – flow emanating from a horizontal wellbore is commonly sluggish; upwards inclined multiphase flow has the largest operating window for slug flow, and wellbore trajectories and inclination fluctuations can produce excessive slugging; existing downhole separators have commonly been designed around steady state conditions, which are not representative of downhole conditions (especially in horizontal wells); separators need to efficiently operate over a broad range of flow rates and gas volume fractions,
- c. fluid gas entrainment or foaming tendencies – free gas can generally be efficiently separated, but entrained gas goes through pump as gas interference; produced fluids generally all have a level of foaming tendency, turbulence can increase the foamy tendency,
- d. high gas velocities can entrain solids and cause excessive erosion and tubing string assembly stuck in hole risk – solids separation is easier when gas is separated first; a packer-style separator risk/limitation where solids separators are commonly placed upstream of the gas separation, and
- e. cyclonic separationⁱⁱⁱ for gas or solids has a narrow efficiency operating envelope – rod pumping is 0% to 200% of flow rates each pump stroke; turbulence suspends solids; foamy fluids suspend solids.

An extensive review of industry literature and research, as well as quality conversations with multiple producers in multiple basins, revealed and disclosed numerous technical limitations and paradigms within existing downhole separators. It also revealed compelling potential solutions to the cited challenges. In other words, it was very apparent that there was an opportunity to improve downhole separation of gases and solids from liquids and to reduce downhole operational risks for sucker rod pumping, as well as for ESP's.

Seven mutually exclusive downhole separation improvement opportunity categories were compiled and extensively studied:

1. separation in an eccentric flow path,
2. limitations of side intakes on separators,
3. flow turbulence minimization,
4. separator intake orientation can take advantage of multiphase flow reversals,
5. hydraulic diameter (conduit shape) in the separation region,
6. process sequence for solids separation, and
7. slug flow tolerance.

SEPARATION IN AN ECCENTRIC FLOW PATH

Figure 2 shows Caetano's^{iv} research discovered that in an annular shaped conduit, with upward flowing co-current and partially counter-current multiphase flow (in the slug and churn flow regimes), liquid slippage or liquid hold-up increases with eccentricity of the annular conduit. In other words, gas can escape up an annulus more easily when a separator's pump intake dip tube is positioned eccentrically to the side versus being concentrically positioned. Their research concluded that upwards of 30% more efficiently gas can escape up a fully eccentric annulus.

Rowlan^v shared a presentation that disclosed that an eccentric annular flow path allows gas to escape more easily. McCoy's^{vi} research also showed that an annular eccentric flow path is more efficient for gas separation.

Such research suggests that any annular flow path used for gas separation should be an eccentrically shaped conduit. This research does also make the technical case that the entire tubing string to surface above a separator should be eccentrically positioned inside the casing.

LIMITATIONS OF SIDE INTAKES ON SEPARATORS

Most of the existing Poor-Boy style packerless separators use side intakes or ports to draw annular fluids into the separator's inner annular separation region and concurrently at the same time to release separated gas out of and back into the annulus. See Figure 1. To maximize a Poor-Boy style separator's separation capacity, the cross-sectional area of the inner annular space (A1 in Figure 1) is often maximized. This is a trade off approach that results in a larger OD of the separator's body and consequently reduces the cross-sectional area of the separator's outer annulus to the well's casing.

Industry literature^{vii} and research^{viii} has revealed that if the superficial gas phase velocity in the casing annulus adjacent to a side intake slot/port exceeds 6 ft/sec (1.8 m/s), liquid's ability to enter the separator diminishes (i.e., the separator becomes starved of liquid and poor erratic pump fillage will undesirably result). This limitation commences at about half the critical liquid lifting superficial gas velocity. When the superficial gas velocity reaches 10 ft/sec (3.0 m/s) the separator becomes fully starved of liquid. At these velocities, the liquid's momentum travelling axially and vertical along side the separator becomes so great that liquid is not able to effectively "turn sideways at 90°" into the separator's intake. The higher the annular gas velocity adjacent to the outside diameter of a side intake separator the less the amount of liquid that can enter the side intake slots / ports. The consequence of limited liquid entering the separator's intake is poor and erratic pump fillage. Such inconsistent pump fillage in turn leads to inconsistent rod loading at the pump, which certainly causes more rapid rod failures (i.e., compressional loading events) and excessive tubing wear (i.e., holes in tubing).

The research further suggested that placing a side-intake separator's intake (slots / ports) in largest casing annulus cross-sectional area minimizes fluid velocities and can therefore improve separation efficiency by 30%. In other words, Poor-Boy separators should have their intakes positioned at the largest

possible cross-sectional area on the casing annulus and most likely at the top of the separator above the separator's inner annulus.

FLOW TURBULENCE MINIMIZATION

Several Packer-Style separators were designed with intentional fluid agitation as part of their gas separation process. It was believed that fluid agitation provided a means to break up emulsions and more efficiently “free the gas” from the liquid. The authors of this paper were not able to find any supporting literature or research that offered appropriate data driven statistical factual evidence that this design practice improves separation efficiency.

On the contrary, Stoke's^{ix} equation for rise/settling velocity of droplets is well known within industry, and research^x (see Figure 4) concludes that fluid agitation and turbulence generate smaller gas bubbles, which are much more difficult to separate. Stoke's equation relates the velocity of gas bubble rise to the bubble radius, densities of gas and liquid, and liquid viscosity:

$$v_{bubble} = \frac{2}{9} \frac{(\rho_{fluid} - \rho_{bubble})}{\mu_{fluid}} g \cdot R_{bubble}^2$$

where g is the gravitational constant. From first principles, then, it can easily be seen that smaller gas bubbles rise at slower velocities. Indeed, lab studies have shown, for example, that a 1/8 inch diameter air bubble in water rises at 1 inch per second, whereas a 1/2 inch diameter air bubble rises at 6 inches per second. It is also apparent that the commonly accepted 6 inches per second gas bubble rise velocity for sizing downhole separators can be misleading and does not accurately represent all downhole conditions. It can be concluded that minimizing agitation and turbulence can improve separation efficiency by 25% or more.

This is a considerable risk for any Packer-Style separator that has a side discharge into the casing annulus (see Figure 1, Packer-Style Separator). A side-oriented discharge can be a region of significant turbulence and fluid agitation. A side discharge will likely result in high velocity multiphase fluid impinging or jetting the casing wall and causing excessive fluid turbulence, which in turn undesirably generates smaller gas bubbles. The flow path through a Packer-Style is more tortuous than a Poor-Boy, which can result in excessive foam generation and fluid gas entrainment (gas entrapment in the liquid that can not be separated downhole) and reduced separation performance. It is common that there is a narrow annular flow path through the separator, from the base of separator below the packer/seal up to the side discharge slot/port. This flow path can have very high velocities and associated turbulence, as all the gas and liquid must travel through it. Such turbulence and fluid agitation generates smaller gas bubbles, which results in gas bubbles that rise at slower velocities.

Producers who have experienced a troublesome high annular fluid level with excessive pump gas interference with a Packer-Style separator, can likely now point to root cause as excessive turbulence in the separator generating smaller gas bubbles and is limiting the separator's performance.

Such research suggests being as gentle as possible with the fluids, avoiding agitation and turbulence, is the best practice for maximizing separator efficiency and performance.

SEPARATOR INTAKE ORIENTATION CAN TAKE ADVANTAGE OF MULTIPHASE FLOW REVERSALS

Technical literature^{xi} (see Figure 5), industry research^{xii} and transient multiphase flow simulations have revealed, under certain conditions and namely inclined upwards flow, that multiphase flow reversals are not only present, but also occur at high frequencies. In other words, liquid loading is a process where liquid reverses and fall gravitationally backwards.

In a wellbore, after the onset of a flow reversal and during the liquid accumulation process, parts of the liquid phase in a multiphase fluid stream move upwards concurrently with the gas, and simultaneously,

other parts of the liquid phase move counter-currently downward with the gas. In other words, parts of the liquid flow will frequently reverse direction from upward to downward. Counter-current flow reversal experiments observed that as the gas rate continues to decrease this partially-concurrent/partially-counter-current liquids behavior progresses up until the point where the liquid's hydrostatic pressure gradient becomes zero (hanging liquid film field) and then after that point, the multiphase flow transitions to a fully counter-current liquid flow (i.e., net liquids flow rate is negative) leading to a maximum rate of liquid accumulation downhole.

Figure 6 provides supportive technical literature^{xiii xiv} and useful illustrations with respect to multiphase flow reversals or liquid fallback in the slug and churn flow regimes. Of note, very little to no stratified flow in the slug and churn flow regimes. This eliminates separator design considerations constraints with respect to liquids falling to the low side of the wellbore.

Figure 5 from the cited research shows that an upward facing separator intake orientation or collector "bucket" can take advantage of such transient, ongoing, partial multiphase flow reversals or liquid fall back. Falling liquids simply fall into the upward facing collector. A simple analogy would be to compare the which fills faster: submerging an open top bucket or submerging a closed top bucket with side slots / ports – the open top bucket fills faster. The research disclosed that a considerable improvement is possible in separation efficiency by more than 50%.

Liquid fallback is very frequent and highly common in the slug and churn flow regimes, which are characterized by high slippage or liquid hold-up. Typical production rates of gas and liquid for sucker rod and ESP pumping in the casing sizes commonly used, the flows are primarily in the slug and churn flow regimes. See multiphase flow pattern maps^{xv} in Figure 7 (green highlight box shows flow regime conditions for 60-600 bbl/day and 30-1000 Mscf/day gas, at 150 psi pump intake pressure).

The researched concluded that separation capacity could be preferentially governed by the rate at which liquid can fallback rather than be governed (or limited) by how fast gas bubbles rise in liquid. Since liquid can fallback faster than gas bubbles can rise, a much greater ability to handle slug and inconsistent flow conditions is now possible. This was a compelling piece of research for the authors for greatly improving downhole gas separation.

HYDRAULIC DIAMETER (CONDUIT SHAPE) IN THE SEPARATION REGION

The shape of a flow conduit, either annular or round tube, greatly affects multiphase flow behaviour and in particular, slippage or liquid holdup.

Research^{xvi} (Figure 8) showed that gas can more easily escape up a round tuber versus in an annulus. An annular shaped conduit has significantly more surface wall contact area than a round tube. This increased contact surface area can allow liquid to bridge, effectively reducing the rate of which gas can escape through the liquid and therefore the rate at which liquid can fall back through the gas.

Nagoo^{xvii} discusses the effect of conduit diameter and shape. In upward bubbly flow, lateral distribution phenomena (and thus interfacial flow parameters) are significantly affected by the conduit hydraulic diameter. For example, in some cases, the wall-peaking void fraction distribution that are common in upward bubbly flow in small diameter pipes can only be found under conditions of low area-averaged void fraction in large diameter pipes. In other cases, at moderate to large area-averaged void fraction conditions, large diameter experimental (air-water) investigations show mostly core-peaking void fraction distributions. Nagoo's critical gas velocity equation for liquid liquids has a quite different critical gas velocity analytical calculation from prior equations that: (1) it is a simple explicit analytical equation that is both inclination and hydraulic diameter dependent, and (2) it is derived from an asymptotic approximation analysis that combines the two outer asymptotes enveloping the full range of onset of liquids flow reversal behaviour. The important understanding from this research is that rate of liquid fallback is diameter dependent

Applying Dr. Nagoo's MAPE^{xviii} superficial gas phase velocity model for critical liquid lifting and comparing the two conduit shape scenarios reveals a considerable difference in the required superficial gas phase velocity to lift liquids is as follows:

Parameters: 250 psi pump intake pressure, 200°F, 0.8 gas gravity, 65% water cut, 1.07 water SG, 35° API oil)

- 5.5" casing is 43 feet per second (13 meters/second)
- 5.5" casing by 2-7/8" tubing annulus is 12 feet per second (3.3 meters/second)

This clearly shows that liquid can much more easily fall back in a round tube versus an annulus. In other words, the critical liquid lifting gas velocity is much higher in a round tube than in an annulus.

Applying a hydraulic diameter calculation to an annular separation area versus a tube area (i.e., no annulus), the results show that for the same cross sectional flow area in a round tube versus an annulus, the hydraulic diameter is much larger for the round tube. For example:

- hydraulic diameter for a round tube conduit is equal to its inner diameter. So, for a tube shape inner diameter of 4.0 inches, with a cross-sectional area of 12.56 inches squared, the hydraulic diameter is 4.0 inches, and
- hydraulic diameter for an annular shaped conduit is calculated as the inside diameter of the outer circle minus the outside diameter the inner circle and for an equivalent cross-sectional area with an inner pump intake tube with an 1.9" outside diameter the resultant hydraulic diameter is 2.5 inches.

This larger hydraulic diameter shows that fluid velocities and Reynolds numbers are much lower in round tube of equivalent cross-sectional area as in annulus – in summary, greater amounts of flow reversals and liquid fallback occurs in a round tube shaped conduit.

This research suggested that separation efficiency is greater with a conduit shaped as a tube versus an annulus and can improve separation efficiency by 50% or more.

PROCESS SEQUENCE FOR SOLIDS SEPARATION

It is far more effective and efficient to separate solids from the liquid after the liquid has been degassed, particularly when flows are highly variable.

The ideal process sequence is to separate out the gas firstly and then separate out the solids. If gas is not separated out firstly, the fluid will have high velocities due to the gas phase being present and therefore solids separation is challenged by erosion and carry over of solids risks. If liquid velocities are lower, solids can be more efficiently separated. Additionally, the presence of gas bubbles in the fluid can effectively increase the viscosity, particularly in the case of foamy fluids, and thus slows the settling of solids due to Stoke's Law.

SLUG FLOW TOLERANCE

It is well known that flow emanating from a horizontal wellbore is commonly inconsistent and sluggish. This can be an explanation for why a well is experiencing erratic pump fillage. Slug flows from a horizontal wellbore can result in frequent undesirable shutdowns due to inadequate pump fillage and gas locking.

When installing a sucker rod pumping system, it is preferable to place the pump as low as possible to maximize the drawdown achievable, thereby maximizing production rate and reserves. However, there is a trade-off in depth of the pump and the rod pumping equipment size and cost. Typically, however, the pump depth needs to be close to, if not at, the kick-off point of the well in order to be able to achieve the

same drawdown as was realized at the end of the natural flow period in order to maintain a smooth transition in production rates.

Placement of pumps above the kick-off point means that slug flows conditions are highly likely below the location of the downhole separator and therefore the downhole separator must tolerate slug flows. This is a concern with side intake Poor-Boy separators, as slug flows are characterized by frequent periods of higher gas velocities that can exceed the levels where the liquid can no longer effectively enter the side intake, consequently causing undesirable excessive gas interference and erratic pump fillage. Figure 9 shows that gas rates above 140 Mscf/day ($4 \times 10^3/\text{m}^3/\text{day}$) in 5.5 inch casing will likely result in poor or erratic pump fillage, followed by frequent/immediate rod pump controller shut downs.

Multiphase fluid liquid slippage is much greater at inclinations between 20 and 60 degrees^{xix}, therefore excessive slugging results in the bend section of a wellbore below the separator. Large gas slugs can effectively bridge the wellbore and lift the liquid column vertical upwards. Therefore, multiple fluid level shots can often show a significant fluctuation fluid level over the course of day.

This undesirable slug flow production behavior with a horizontal wellbore can be caused or made worse by the horizontal wellbore's trajectory. A horizontal wellbore's trajectory greatly influences the flow behaviour emanating from the horizontal wellbore. If a wellbore's directional survey is primarily in a toe-up direction, flows tend to be excessively sluggish characterized by larger amplitude lower frequency gas slugs (akin to Old Faithful Geyser^{xx}), as the low point of the wellbore near a well's heel acts as an unstable gas trap (i.e., liquids pool until the gas pressure in the well's toe pushes a large slug up the wellbore). If a wellbore's directional survey is primarily in a toe-down direction, flows tend to be characterized by smaller amplitude higher frequency gas slugs. In the case of a toe up and then toe down (i.e., a hump in the middle of the lateral) trajectory, gas slug surges are caused by the toe up section unloading violently. Figure 10 shows a troublesome up/down horizontal wellbore trajectory and the resultant slug flow gas rate surging that leads to poor /erratic pump fillage and frequent pump shut downs. This also suggest why side intake poor-boy separators are generally not slug flow tolerant.

The vertical height of a fluid level in a well's annulus can also affect slugging severity. When a well's annular fluid level is pumped down, the pump intake pressure becomes lower. At lower pressures gas volumetrically and exponentially expands (with solution gas liberation) and high gas velocities and gas volume fractions (GVF's) consequently result. Gas slugs therefore have instantaneously high gas GVF's and associated gas velocities which can cause excessive pump gas interference with lifting of the liquid column in the annulus. Shutting of the well down by the pump off controller due to poor pump fillage worsens the gas surge/slug problem by undesirably allowing the well to build up more energy during the shut down period (more built-up energy means the greater the surge rate). A vicious circle of on/off pumping is happening in this case. In conclusion, poor-boy separators are not able to handle slug flows effectively due to their side intake slots/ports.

Preventing/suppressing the gas surges/slugs will also protect the pump from excessive solids. Those surges have high enough velocities to carry solids in a damaging concentrated mass to the pump. Slugs are the primary mechanism for transportation of solids along a horizontal wellbore^{xxi}.

To dampen troublesome slug flows below a separator placed above a kick-off point, reduced internal diameter tailpipes (with seal on the bottom) have been placed around a wellbore's bend section and have proven to be beneficial. For example, the HEAL System^{xxii} actualizes the benefits gas lift by lowering a section of production tubing into the bend and reducing tubing internal diameter to achieve critical liquid lifting gas velocities that beneficial provide fluid flow stabilization from the horizontal to above the kick-off point. In turn, a sucker rod pump and separator can be placed higher and out of the bend, in the vertical where it is designed to be most efficient and reliable. From an operational risk perspective, there have been challenges with tailpipe systems; they can be very risky and complex to retrieve and therefore adoption of such practices has been limited. Until such operational risks can be controlled or mitigated, use of tailpipes for dampening slug flows will be limited.

NEW AND IMPROVED DOWNHOLE SEPARATOR CONCEPT – THE WHALESHARK

It was hypothesized that downhole gas and solids separation could be greatly improved by taking advantage of such transient, ongoing, partial flow reversals using an upward facing separator collector intake. In addition, separation efficiency could further improve by combining eccentric flow paths and a non-annular conduit shape for the gas separation region. It was also hypothesized that operational risks could be lowered with elimination of the need of annular packer or seal.

In summary, the following design aspects were proposed:

- avoid being governed and limited by gas bubble rise velocities through taking advantage of liquid phase flow reversals (governed by how fast liquid falls, as oppose so gas bubbles rising)
- orienting the separator's intake to face upwards to function as a collector of liquid fallback, thereby intentionally taking advantage of the transient, frequent, ongoing, liquid phase flow reversals and liquid fallback
- reduce the annular clearance adjacent to the separator's collector to increase the multiphase fluid velocity for increasing its gas volume fraction (GVF) to reduce the amount of small sized bubbles (forcing bubble coalescence) and to maximize the mouth-size of the separator's collector intake
- eliminate abrupt flow path changes to effectively minimize turbulence
- use an exceptionally large cross-sectional area with an "open tube, unobstructed center line" eccentric separation region immediately above the collector to promote a greater amount of liquid fallback into the collector
- packerless – eliminate a packer or cup seal to minimize fluid turbulence to lower operational risk

A separator prototype was then designed, built, extensively flow loop tested and successfully field implemented. The concept is illustrated as in Figure 11. In summary, its key unique engineered features:

- a large diameter upward facing collector intake,
- a separation region immediately above the collector intake that is characterized by "no annulus" by use of an eccentric (i.e., to the side) placement of the pump intake dip tube,
- an oval pump intake tube to maximize its distance away from the center line of the well's casing, which maximizes the rate of liquid fall back into the collector, and
- a highly efficient solids separation system adopted from proven surface separator technology that uses momentum and gravity separation as opposed to cyclonic.

The WhaleShark's Separation Region above the collector intake is shown as A3 in Figure 11. It is fully eccentric with "no annulus" and is engineered to promote/maximize liquid phase flow reversals or the rate at which liquid falls back into the collector. Figure 12 shows pictures of the WhaleShark Separator.

Under slug flow and inconsistent surging conditions, the WhaleShark separator will be more capable of sustaining high pump fillage and it will suppress slug flows. Since it is governed by the rate at which liquid falls backwards into the collector and as long slug/surge velocities do not exceed critical liquid lifting gas velocities in the Separation Region, high pump fillage will be achieved. Therefore under slug/surge flow and flumping conditions, continuous pumping at consistent good pump fillage is now possible (which beneficially protects the pump/rods from excessive erratic cyclical stresses, especially from starting and stopping).

Figure 13 shows a detailed cutaway of the WhaleShark separator. Note that the length of the separator is 18 feet long. Since the separator is governed by how fast liquid can fallback, excessively long lengths are no longer required (as with separators that are governed by gas bubble rise velocity). The Separation Region has two spiral shaped half-gussets connected to the rigid bar and the oval pump intake tube for torsional strengthening and guiding of the separator into and out of the well. These gussets are designed and shaped to not impact the separation efficiency. The WhaleShark's tensile strength capacity was designed and has been fully bench tested to be the equivalent to a 2-3/8" EUE tubing coupling.

Figure 14 illustrates the WhaleShark separator's liquid phase velocity profiles. As previously discussed, poor-boy separators are limited by the gas velocity in the annulus adjacent to their side intake slots/ports. For the WhaleShark's design, the higher the gas velocity along side the separator's collector the more efficient the separator becomes. Higher gas velocities result in less fluid slippage between the gas and liquid phases. Less slippage means the gas volume fraction (GVF) of the multiphase fluid increases. Beneficially, a higher gas volume fraction coalesces the gas into larger gas bubbles, which then separate from liquid more easily when they enter the WhaleShark's Separation Region. When multiphase flow reaches the top of the separator's collector, it enters the Separation Region radially and circumferentially close/adjacent to the casing wall. This radially upward moving multiphase flow creates a very important funnel shape that beneficially guides the separated liquid to the center region and then counter-currently downward directly into the upward facing shroud intake.

If well production of fluids results in flows that are in the Bubble Flow regime (which generally occurs at gas volume fractions less than 25%^{xxiii} within the typical sucker rod pumping superficial gas and liquid velocity ranges), this design of separator becomes governed by gas bubble rise velocity, as the gas bubbles are not coalescing into larger gas bubbles as in the slug and churn flow regimes (where a large amount of liquid fallback is occurring).

The design permits high-rate flumping conditions (critical liquid lifting in the annulus and/or flowing out the casing annulus) while sustaining full pump cards. Since the Separation Region required very high gas velocities to reach the critical liquid lifting gas velocity (48 feet per second in 5.5" casing), liquid will continue to fallback into the collector, sustaining full pumps cards during flumping out the annulus.

FLOW LOOP TESTING PROOF OF CONCEPT

A physical and near scale model of the WhaleShark was built and was then extensively tested in a flow loop. Figure 15 shows pictures of a test and liquid falling backward into the upward facing collector.

Figure 16, shows the condition of the collector intake upon flow loop shut down. Probably the most exciting moment in the design of the WhaleShark separator was realization and proof that the collector remains full and that little to no gas separation occurs inside the collector. Liquid falling backwards maintains a full collector. It was the first time we were able to physically observe that the separator is governed by how fast liquid can fall and not be gas bubble rise velocity and is able to set new benchmarks in downhole separation performance.

Flow loop testing confirmed:

- achieved 100% separation efficiency
- having a separation region above the collector that effectively has "no annulus" using an eccentric and oval-shaped pump intake tube significantly improves separator performance
- taking advantage of multiphase flow reversals with upward facing intake significantly enhances separation
- more efficient and greater capacity than packer-style separators
- ability to handle sluggy and inconsistent flows

DOWNHOLE SOLIDS SEPARATION DESIGN

A solids separation feature was added to the WhaleShark. As previously discussed, packerless separators have the advantage of separating solids after the liquid has been degassed.

Figure 17 details the solids separation feature.

A cyclonic type solids separation system was intentionally avoided due to their narrow operating range limitations. We desired a design that could efficiently separate solids from 0% to 200% (i.e., the rate on the pump intakes liquid on the upstroke) of the flow rate, aligned to expected rod pumping conditions and

highly variable flow conditions. It uses a simple/efficient gravity and fluid momentum solids separation system. An angled weir guides liquids/solids to the velocity acceleration dip tube (which is intentionally positioned on the opposite side of the pump intake tube).

The pump intake tube is also intentionally positioned vertically shallower than the lowermost edge of the weir's velocity dip tube, even at high wellbore inclinations. Liquid will always have to move upwards against gravity to reach the pump intake tube. Gravity therefore assists the separation of solids. The solids velocity dip tube is designed to increase the downward velocity and momentum of the solids, which encourages the solids to travel downward into the sump/mud joints. Degassed (gas depleted) and solids free liquid must then travel upwards and across to the pump intake tube, which encourages solids to gravitationally settle into the sump.

The system efficiently separates solids into retrievable and adjustable length mud joints. Mud joints can be simply standard tubing joints.

PLACEMENT OF SEPARATORS AT INCLINATIONS

Figure 18 shows a wellbore schematic with a WhaleShark placed at a high inclination. For gas separation, the WhaleShark is designed to efficiently separate gas from liquid up to 80° inclination. Literature has shown that gas-liquid separation is most efficient around 40°-45° inclination^{xxiv}. At inclinations, liquid can more easily collect at the low side of the casing and gas can more easily escape on the high side. This increases the rate of liquid fallback into the WhaleShark's upward facing collector and therefore increases separation efficiency (about 30% more efficiency at 40°-45° inc). Orientation of the separator does not matter since the collector's large open mount covers most of the casing internal diameter.

For solids separation in a wellbore, solids settle to a maximum of about 65° inclination. At 65°, solids stack out and do not settle downward to higher inclinations. This is termed the angle of repose, and can be seen in natural features like a rocky mountain scree slope or sand dune. The design of the vertical spacing of the Velocity Acceleration Tube and the Pump Intake Tube, is such that it will still have a vertical distance when the separator is placed at 65°, and gravity separation of solids still occurs. If solids are a risk and for these reasons, it is not recommended to place a separator beyond 65° inclination.

WELLBORE CONFIGURATIONS AND TUBING ANCHOR CATCHER AND TUBING HANGER TENSION CONSIDERATIONS

Sucker rod pumping must be engineered as a system from the bottom to top of the well. Figure 19 illustrates common wellbore configurations being actively used for sucker rod pumping with the WhaleShark separator. Tubing anchor catchers (TAC's) are placed above the WhaleShark.

TAC recommended practices are an important part of a sucker rod pumping system. It is very important to assess the annular flow-by cross section area of a TAC to ensure it is not a flow restriction. The tubing anchor catcher (TAC) annular flow-by clearance can be the root cause of excessive pump gas interference and foam generation. To control this risk, we always recommend use of slimhole or slimline high annular flow-by TAC's.

If the gas velocity in the TAC's annular cross-sectional area reaches a velocity where it can lift all the liquids (i.e., the liquid cannot fall back downward), separation of gas from the liquid will not occur and pump gas interference will be excessive (indicated by poor and erratic pump fillage and high annular fluid levels). A liquid column will build in the annulus above the TAC until the pressure and gas velocities subside below the critical liquid gas velocity – at which point liquid can fall back past the TAC and pump fillage returns to high levels; this undesirable cycle can repeat itself over and over many times per day. This undesirable condition commences at approximately 6 feet/second (1.8 m/s) of superficial gas velocity. If a TAC is the component with smallest and most restrictive annular cross-sectional area, it will

be the region of greatest critical liquid lifting risk (i.e., the gas velocity where are liquid is lifted). Therefore, a TAC's annular flow-by cross-sectional area must be maximized. For example, an inadequate plan would be to run an annular restrictive packer (with packing element removed) as a TAC. Use a critical liquid lifting gas velocity/rate calculator to check such risks.

See Figure 20^{xxv} which illustrates an undesirable drawdown limiting scenario can occur where the well is pumping off in the annular space between the separator and the TAC (i.e., pump is showing gas interference), but with a large fluid column remains above the TAC in the annulus. McCoy et al^{xxvi} wrote an excellent technical paper describing the consequences of annular restrictive tubing anchor catchers. shows an undesirable fluid level being created above an annular restrictive TAC. Figure 20 also shows an illustration of the annular flowby cross sectional area difference between a slimhole type TAC and a restrictive standard TAC.

From a system perspective, a design should always be such that the TAC remains in tension to avoid risks of TAC becoming unset or compressional tubing loadings causing excessive rod wear/stress. The minimum required Tubing Hanger Tension must be calculated considering multiple scenarios, including:

- reservoir fluid temperatures heating up tubing after starting pump
- tapping of the pump
- filling the tubing after pump is started
- annular fluid level dropping
- coefficient of thermal expansion and temperature fluctuations during operations and workovers

Resultant calculations are often higher than the standard practice of 10,000 lbs tubing hanger tension being deemed adequate. An example calculation can be seen in Figure 21.

CASE STUDIES

Multiple case studies in multiple United States and Canadian basins, demonstrate improved downhole separation performance has been achieved by the WhaleShark.

Case Study 1 – Figure 22 shows exceptional downhole separation performance recorded from Mississippian Lime horizontal wells in Oklahoma and data driven results from overlayed downhole pump cards. The trend of downhole pump card overlays shows consistent pump fillage and high pump fillage in 5.5" casing at high gas liquid ratios (GLR's), using tubing pumps. Complete and consistent pump fillage was achieved at 500-600 bbls/day liquid and 1.3 to 1.8 MMscf/day gas rate. These results also demonstrated that flumping up the annulus with consistent high pumping fillage is now possible with a separator that is not governed and limited by gas bubble rise velocity.

Case Study 2 – Figure 23 shows a result in the DJ Basin Niobrara play. Play characteristics include gassy light oil with a high foaming tendency. A poor-boy separator was replaced after showing very inconsistent pump fillage but had fairly decent average pump fillage (around 85%). The WhaleShark showed stable and consistent high pump fillage, averaging over 95 percent.

Case Study 3 – Figure 24 shows a comparative in the Texas Permian play. This is an excellent case history of good downhole separation versus poor downhole separation (in higher foamy tendency produced fluid environments). Both wells recently came off ESP's, have similar 2000 GLR foamy fluids production and the same number of days from initial rod up. The most recent cards in their trend tell the story post load fluid recovery – the WhaleShark well was moving 450 bbls/day of fluid and separating out all the free gas, whereas the other well is less than half that rate (same pump sizing and stroke rate) and is not separating out all the free gas. The WhaleShark cards are smooth with very consistent over laying 75% pump fillage, whereas the poor-boy separator's most time recent pump card is showing only 40%-80% erratic fillage and is "rough" looking. The WhaleShark pump being smooth indicates that it has removed the majority of the free gas from the liquid. The consistent 75% pump fillage is compression of

entrained gas from the fluids having a higher foaming tendency. With little free gas in the tubing means no gas slugging is occurring in the tubing and therefore the pump cards are smooth. The poor-boy is not separating out the free gas and therefore free gas is entering the pump/tubing, which is resulting in excessive gas slugging up the tubing (i.e., rough looking cards). This is also indicated by the tubing hydrostatic fluid load on the pump during the upstroke. The WhaleShark well's pump has approximately 10,000 lbs of load, whereas the poor-boy's pump has only 5,000 lbs. Again, the poor-boy has free gas is going into the tubing (inadequate separation) and is reducing the hydrostatic pressure load on the pump, which is greatly reducing pump efficiency and the amount of liquid being pumped per day. It can also be seen that the poor-boy's pump card does not reach the zero line – also indicative of excessive free gas in the pump and tubing above (showing up as excessive rod friction and high pressure loss through the pump's travelling valve).

Case Study 4 – Figure 25 shows a comparative of a weighted intake poor-boy separator and separator placement at a high inclination of 60°. The Canadian Charlie Lake play is characterized by gassy/foamy water and oil production. The WhaleShark successfully improved separation, reduced gas slugging and increased production at same pump strokes per minute.

Case Study 5 – Figure 26 shows increase drawdown reliably while reducing workovers on a Canadian Montney play horizontal well with gassy foamy oil/water production. The WhaleShark replaced a low reliability poor boy separation system. Rod failures were occurring every couple months. Since the early April 2021 install the well is still operating, therefore the WhaleShark successfully improved production and rod lifting reliability. Interestingly, the producer chose to rod lift the next well instead of gas lifting due to this result.

Case Study 6 – Figure 27 shows a 35 series WhaleShark successfully handling 2.7 MMscf/day (75 E³m³/day) and 2,000 bbls/day (320 m³/day) inside heavy 5.5" (139.7mm) casing. This Canadian Charlie Lake well used a 35 series WhaleShark separator (3.5" OD collector intake) inside 5.5" (139.7mm casing), heavy wall at 23 #/ft (34.2kg/m) with an ID of 4.7" (118.6mm). This well demonstrated successful flumping up the annulus while sustain nearly full and consistent pump cards and is likely a downhole separation record and new benchmark for inside 5.5" casing.

Case Study 7 – Figure 28 shows pump fillage trends before using a packer-style and a poor-boy separator and after for when using the WhaleShark separator in the North Dakota Bakken play. These were pro-active pulls aiming to improve production performance. Significant improvements in pump fillage consistency and average pump fillage were achieved.

CONCLUSION

Multiple case studies in this paper fully demonstrate, repeatably and reproducibly, that taking advantage of multiphase flow reversals can enhance downhole separation performance and capacity, while at the same time lower operational risk. This approach simplifies the production strategy with offering a broader range and earlier transitions to sucker rod pumping, effectively reducing CAPEX and OPEX to deliver a lower cost per barrel over the lifecycle of the well.

FIGURES

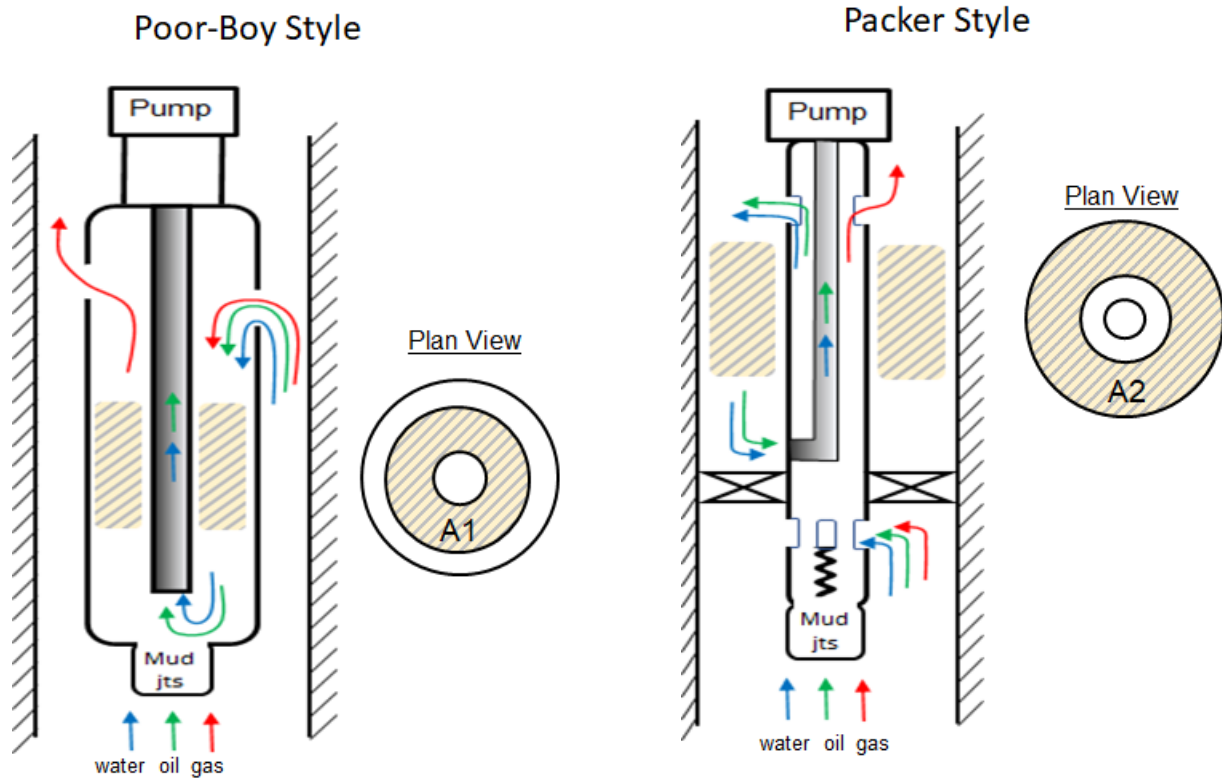


FIGURE 1 – POOR-BOY AND PACKER STYLE DOWNHOLE SEPARATORS

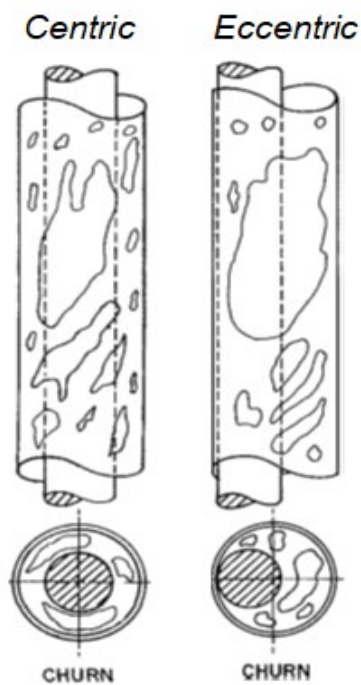


FIGURE 2 – PLUS 30% IMPROVEMENT IN SEPARATION EFFICIENCY WITH ECCENTRIC POSITIONING OF PUMP INTAKE'S DIP TUBE

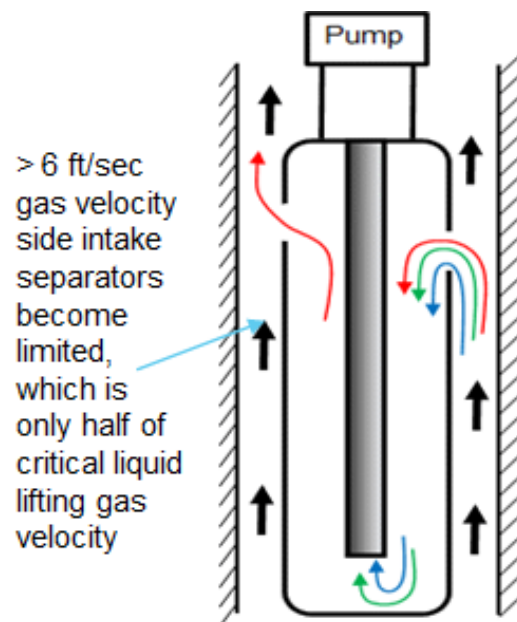


FIGURE 3 – PLUS 30% IMPROVEMENT PLACING A POOR-BOY SEPARATOR’S INTAKE IN LARGEST CROSS-SECTIONAL AREA

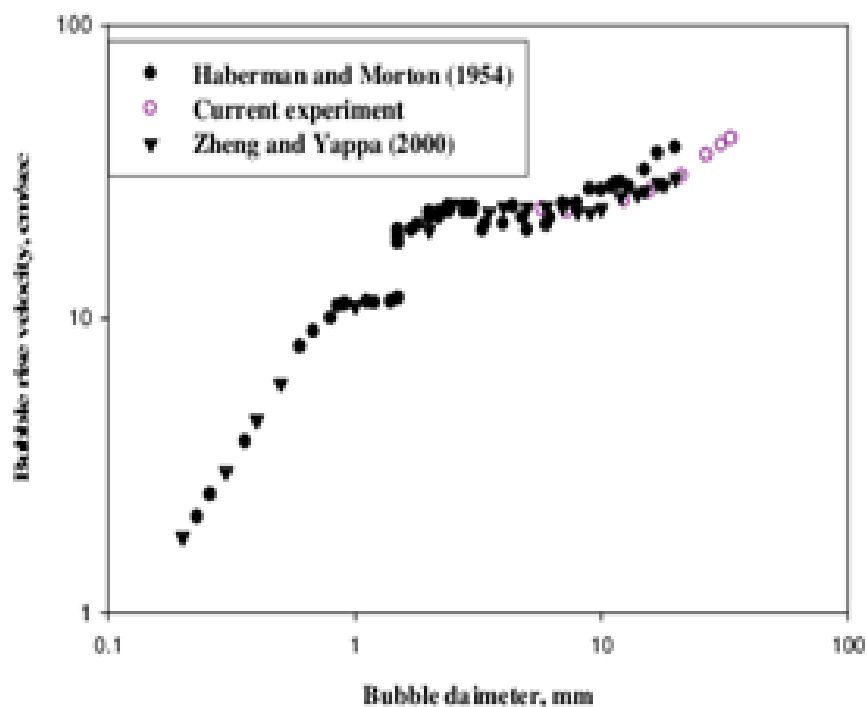


FIGURE 4 – SMALL GAS BUBBLES RISE SLOWER; A PLUS 25% IMPROVEMENT IN SEPARATION EFFICIENCY MINIMIZING FLUID AGITATION AND TURBULENCE

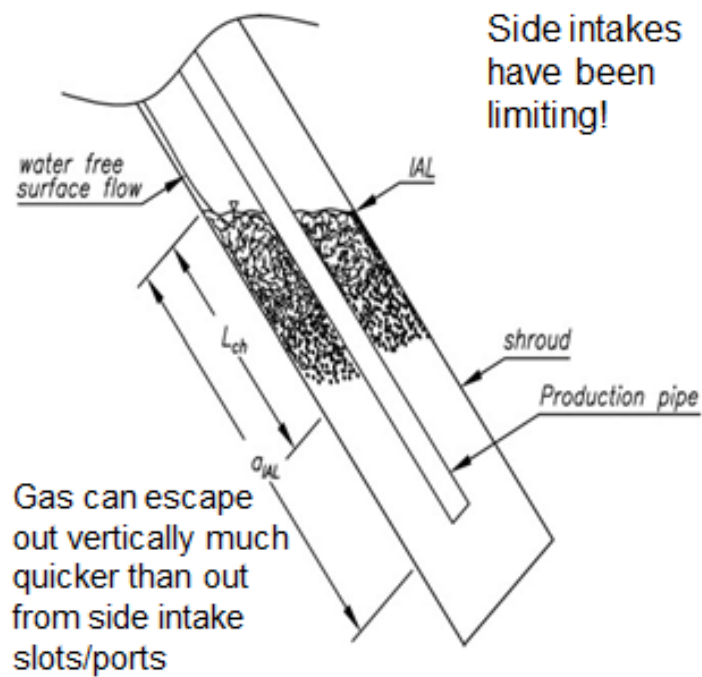


FIGURE 5 – PLUS 50% IMPROVEMENT IN SEPARATION EFFICIENCY RE-ORIENTING SEPARATOR INTAKE FROM SIDE TO FACING UPWARD; AN UPWARD FACING SEPARATOR INTAKE TAKES ADVANTAGE OF MULTIPHASE FLOW REVERSALS OR LIQUID FALLBACK

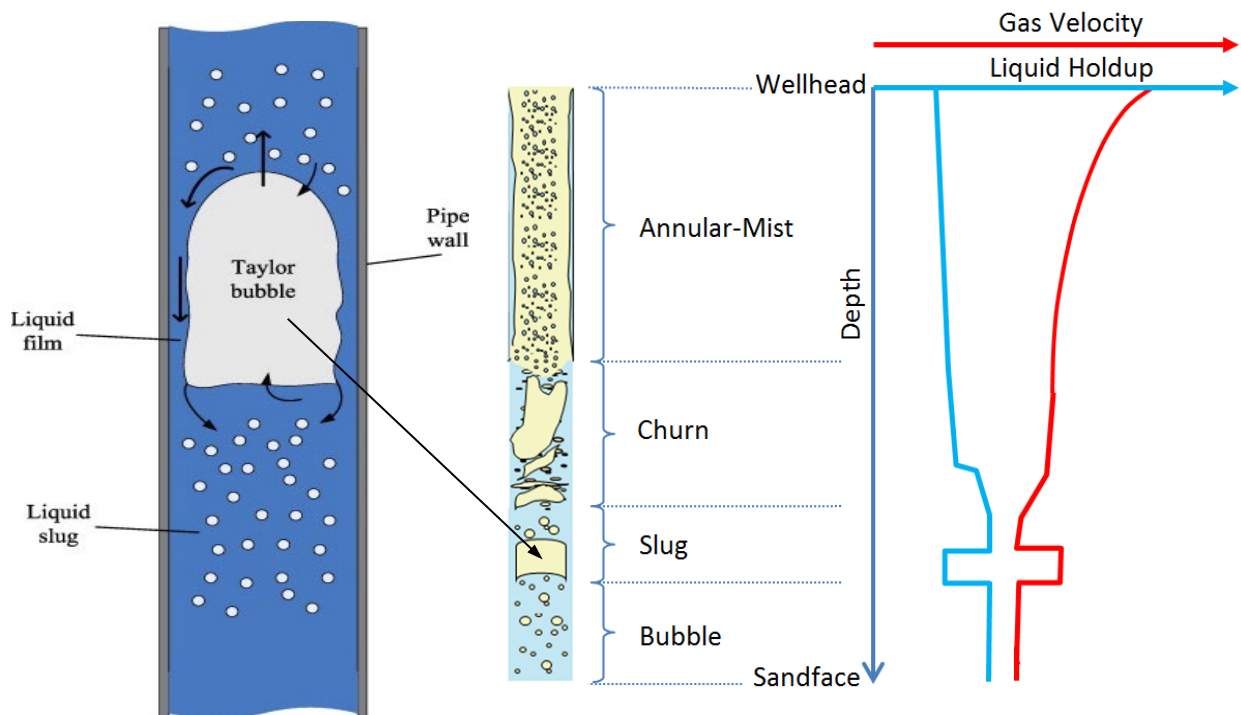


FIGURE 6 – SLUG FLOW AND LIQUID PHASE FLOW REVERSALS (LIQUID FALLBACK) IN VERTICAL PIPE FLOW

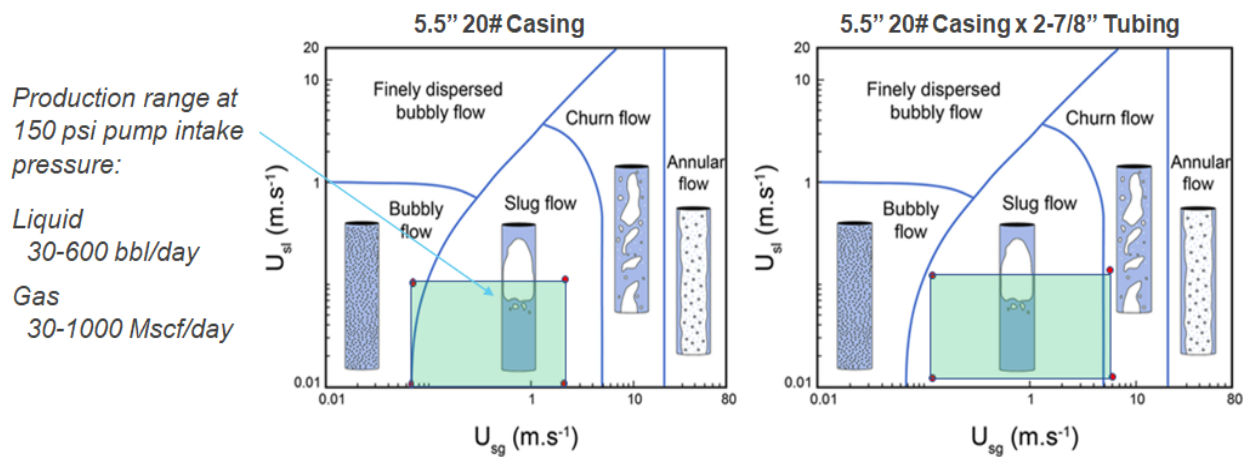


FIGURE 7 – MULTIPHASE PHASE FLOW PATTERNS IN 5.5" 20# CASING; ROD PUMPING IS IN SLUG AND CHURN FLOW REGIMES CHARACTERIZED BY MULTIPHASE FLOW REVERSALS

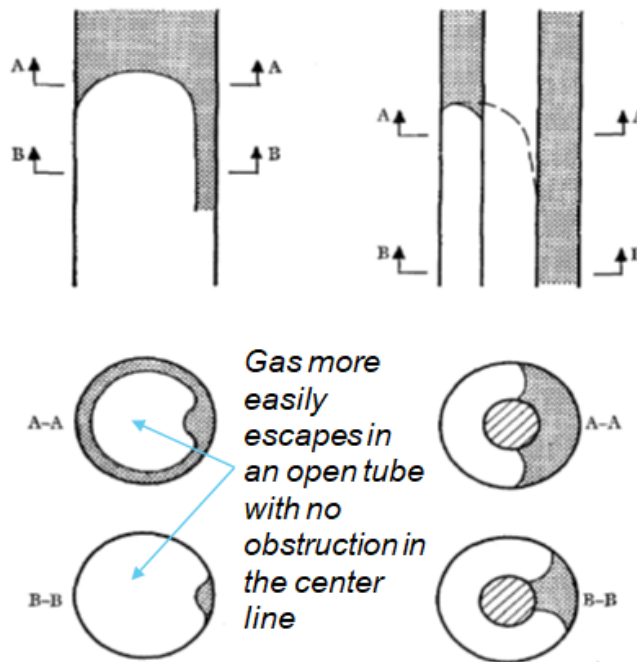


FIGURE 10. Two variant bubble shapes.

FIGURE 8 - SEPARATION IN AN ANNULUS SHAPED CONDUIT IS LIMITING; OPEN TUBE SHAPED CONDUIT IS MORE EFFICIENT FOR GAS SEPARATION

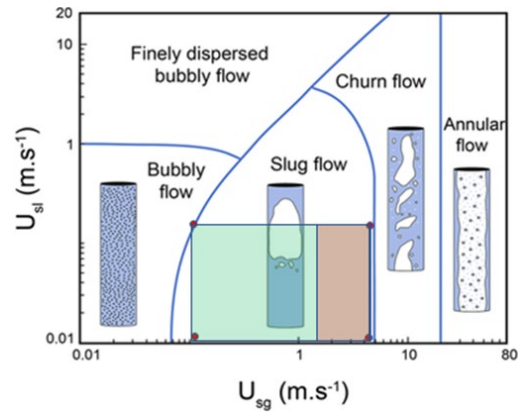


FIGURE 9 – SIDE INTAKE SEPARATOR BECOMES LIMITED ONCE SUPERFICIAL GAS PHASE VELOCITIES ADJACENT TO PORTS/SLOTS EXCEEDS 6 FEET/SECOND (1.8 METERS/SECOND)

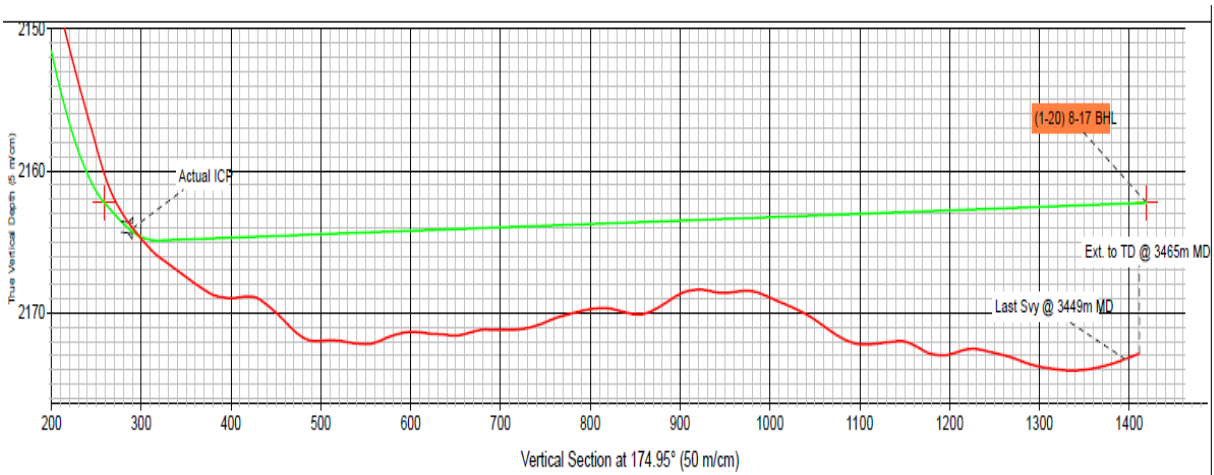
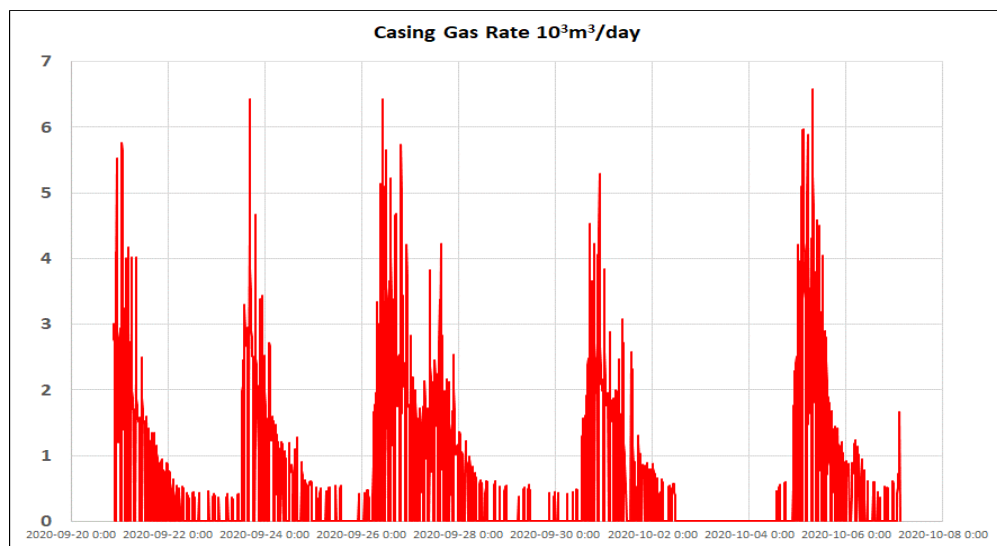


FIGURE 10 – SLUG FLOW BEHAVIOR CAUSED BY A TOE-UP HORIZONTAL WELLBORE TRAJECTORY

WhaleShark

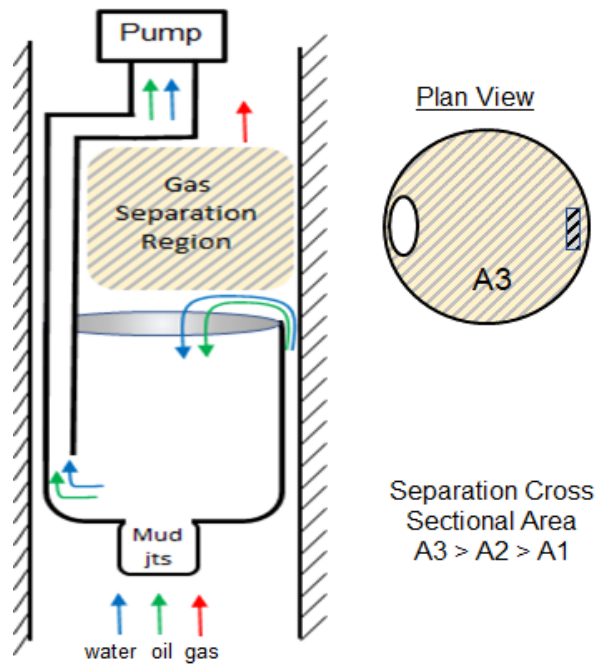


FIGURE 11 – NEW CONCEPT DESIGN; WHALESHARK



FIGURE 12 – WHALESHARK SEPARATOR’S “NO ANNULUS” SEPARATION REGION ABOVE THE UPWARD FACING COLLECTOR INTAKE

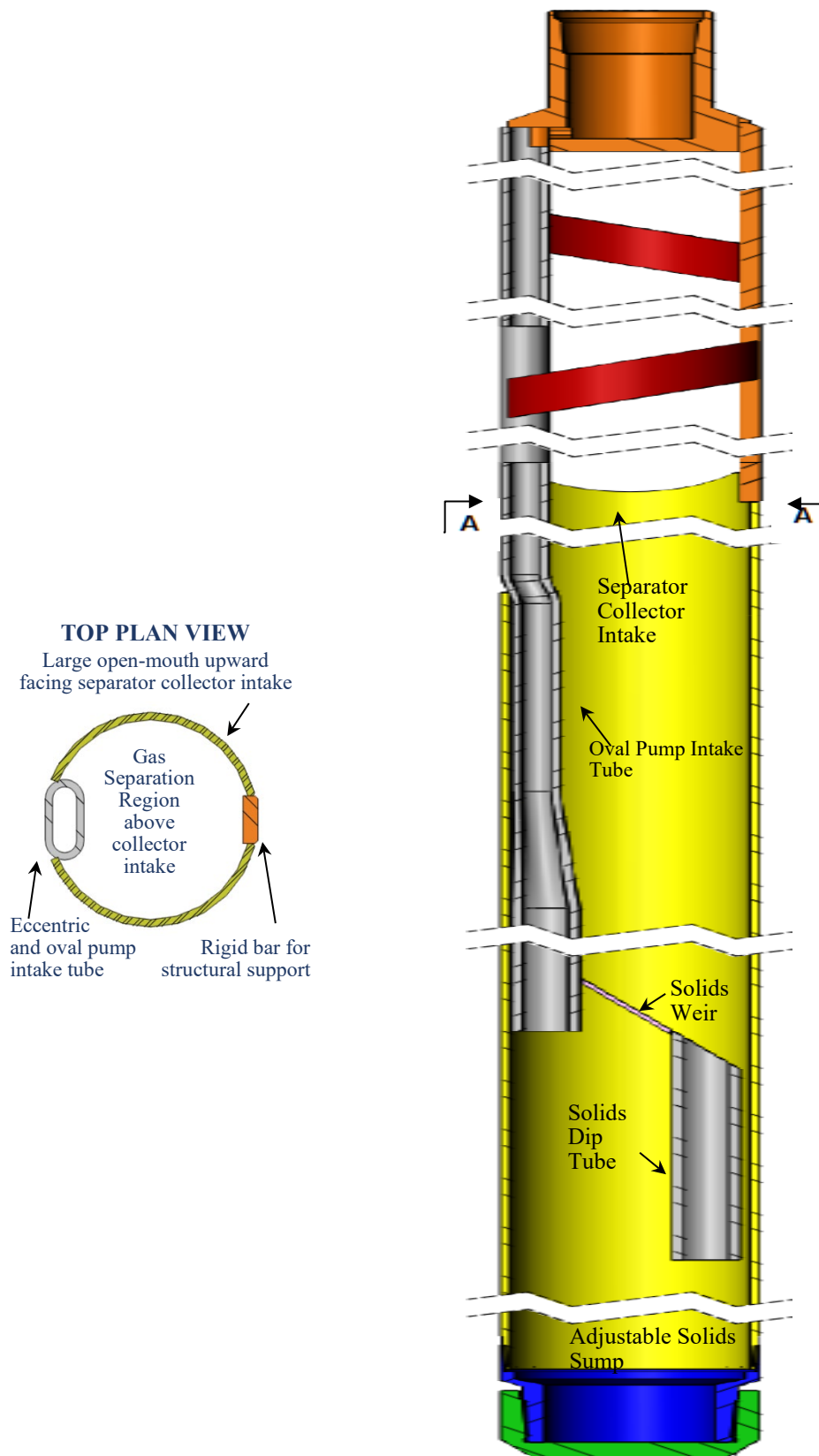


FIGURE 13 – WHALESHARK SEPARATOR CUT-AWAY

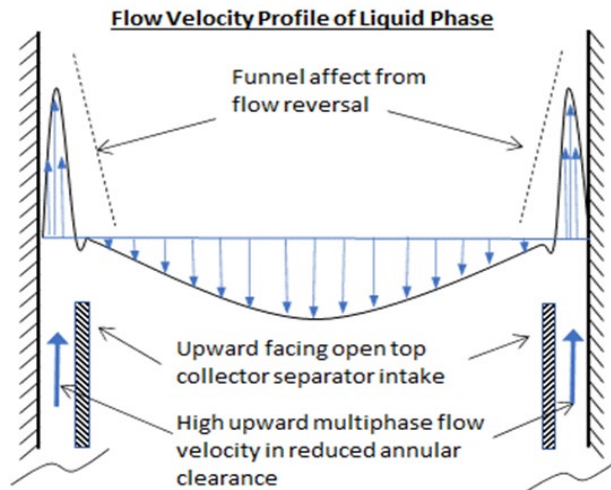


FIGURE 14 – WHALESHARK SEPARATOR INTAKE COLLECTOR VELOCITY PROFILE; HIGH VELOCITIES ADJACENT TO THE COLLECTOR INCREASE SEPARATION EFFICIENCY



FIGURE 15 – FLOW LOOP TESTING SHOWING LIQUID FALLBACK COMENCING FROM IN SEPARATION REGION AND THEN DOWN INTO THE SEPARATOR'S UPWARD FACING COLLECTOR INTAKE



FIGURE 16 – SEPARATOR’S COLLECTOR FULL OF LIQUID UPON FLOW LOOP SHUT DOWN DEMONSTRATING ALMOST ALL GAS SEPARATION IS OCCURING ABOVE THE COLLECTOR IN THE “NO ANNULUS” SEPARATION REGION (DUE TO LIQUID FALLBACK AND NOT GAS BUBBLE RISE VELOCITY)

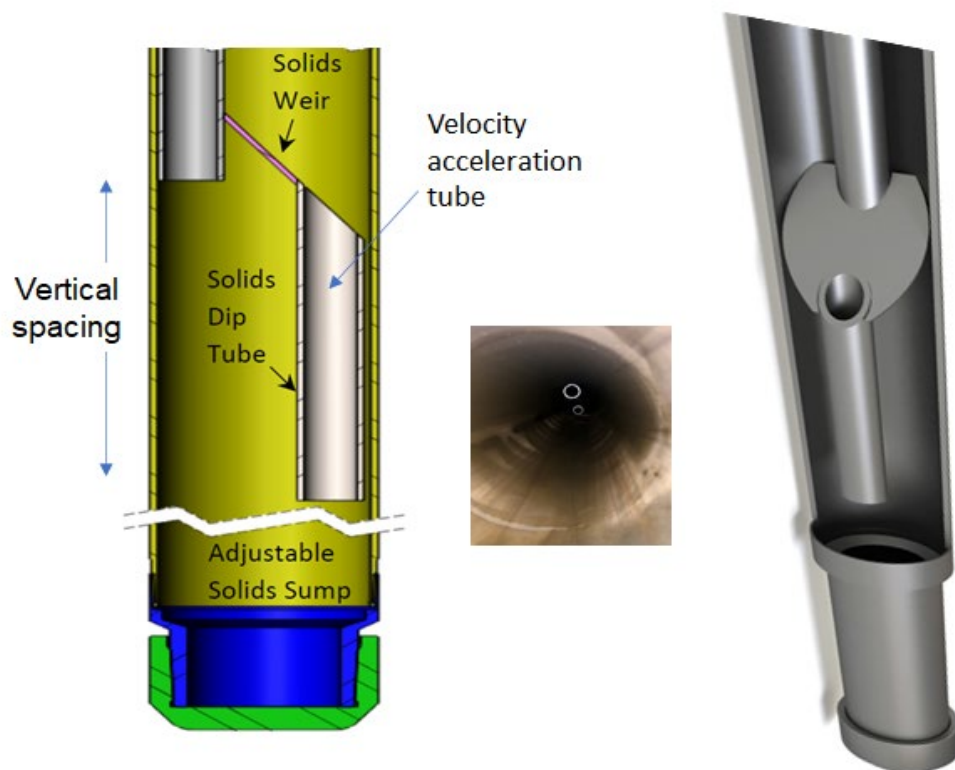


FIGURE 17 – MOMENTUM AND GRAVITY BASED SOLIDS SEPARATION FEATURE

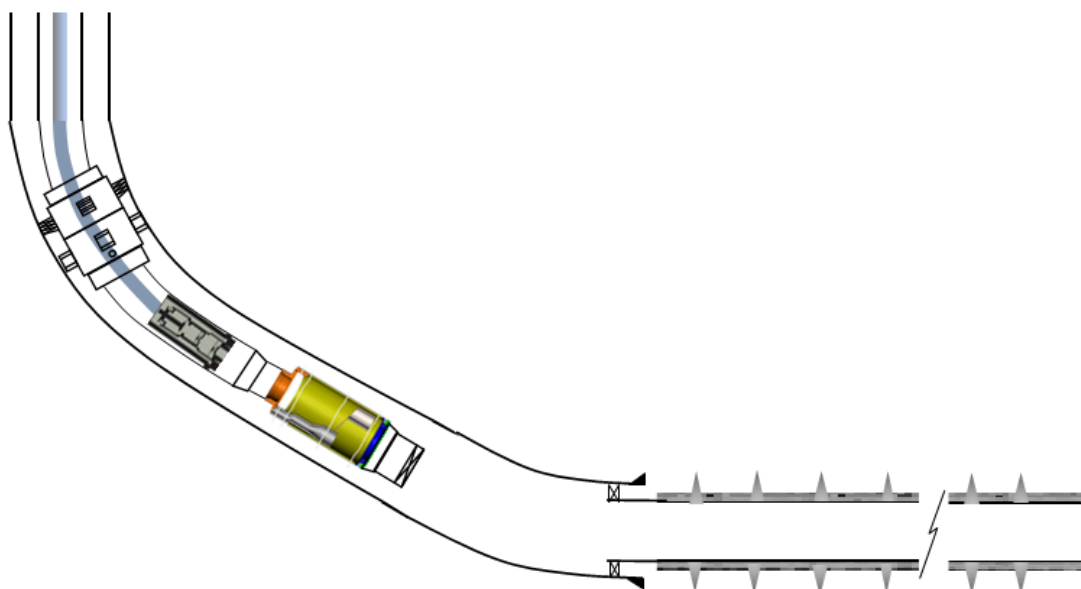
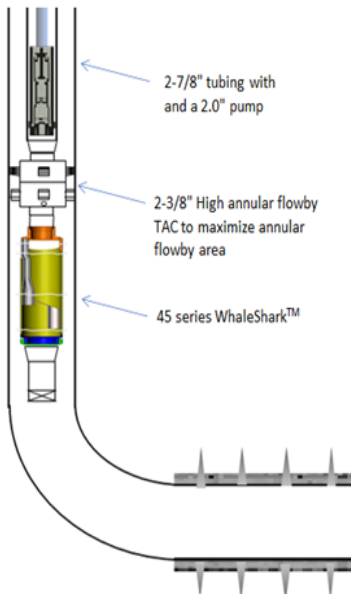
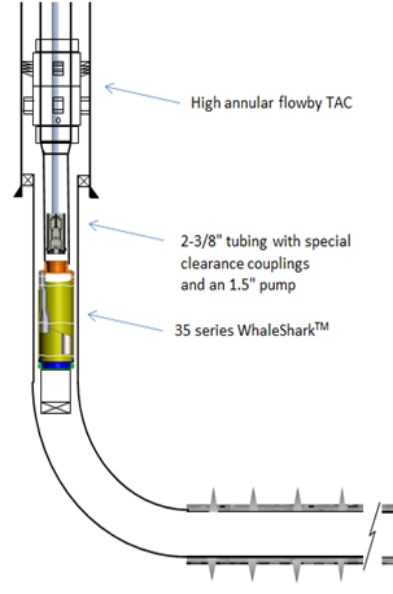


FIGURE 18 – PLACEMENT OF A SEPARATOR AT INCLINATIONS

Sucker Rod Pumping (5.5" casing)



Sucker Rod Pumping (inside 4.5" liner)



Sucker Rod Pumping (7" casing)

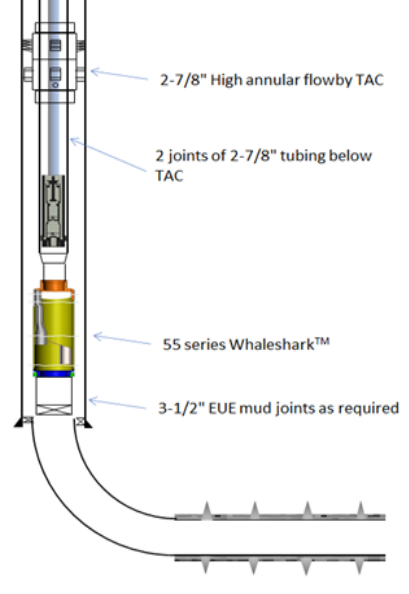


FIGURE 19 – TYPICAL WELLBORE CONFIGURATIONS

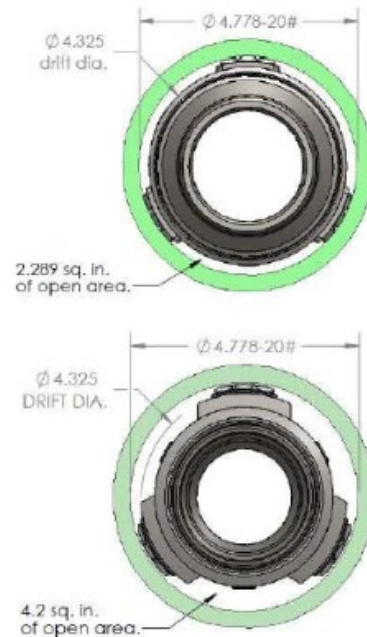
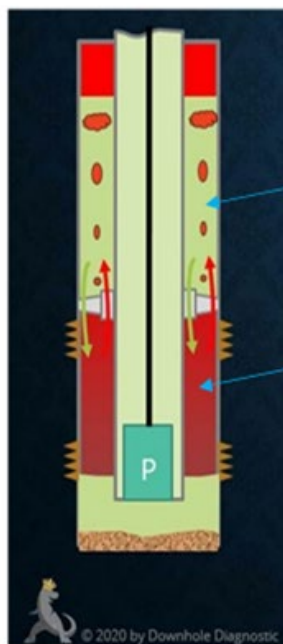


FIGURE 20 – TUBING ANCHOR CATCHER ANNULAR FLOW-BY CLEARANCE


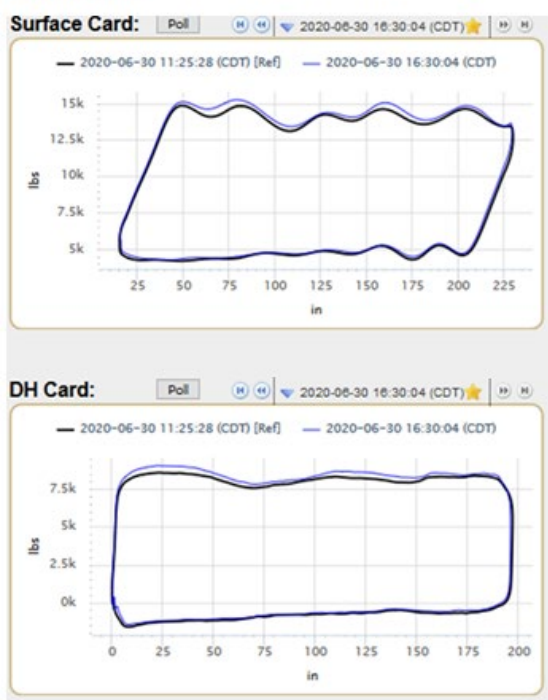
| | | |
|---|---------------|-------------------|
|  Tubing Anchor Tension Calculator | | |
| | Imperial | Metric |
| Tubing OD (inches) | 2.875 | 73.0 mm |
| Tubing ID (inches) | 2.44 | 62.0 mm |
| Tubing Type | J55 | |
| Reservoir temp (°F) | 160 | 71 °C |
| Producing wellhead temp (°F) | 100 | 38 °C |
| Static wellhead temp (°F) | 65 | 18 °C |
| Pump Depth (MD-ft) | 5446.2 | 1660 mMD |
| Packer or Anchor Depth (MD-ft) | 5382.2 | 1641 mMD |
| PIP at Pumped Off (psi) | 100 | 689 kPa |
| Annular Surface pressure (psi) | 80 | 552 kPa |
| Running Tubing pressure (psi) | 200 | 1379 kPa |
| Overpull Required at Surface (in) | 12 | 0.30 m |
| Extra load for "pump tap" case (lbs) | 5000 | 2200 daN |
| Tension to leave on anchor (lbs) | 5000 | 2200 daN |
| Surface Pull Required (lbs) with 12" of overpull | 59,500 | 26,180 daN |
| Tubing Strength (80% of book value) | 79,800 | 35,112 daN |
| Expected RIH string weight (lbs) (assumed pump depth fluid) | 34,900 | 15,356 daN |
| Expected RIH string weight (lbs) (assuming tubing full of water) | 30,600 | 13,464 daN |
| Required Tension on Tubing Hanger when landed (lbs) | 18,900 | 8,316 daN |

FIGURE 21 – TUBING HANGER TENSION CALCULATION

Well #1



Well #2



FIGURE 22 - CASE STUDY 1 – HIGH GAS RATE AND GAS LIQUID RATIO IN 5.5" CASING

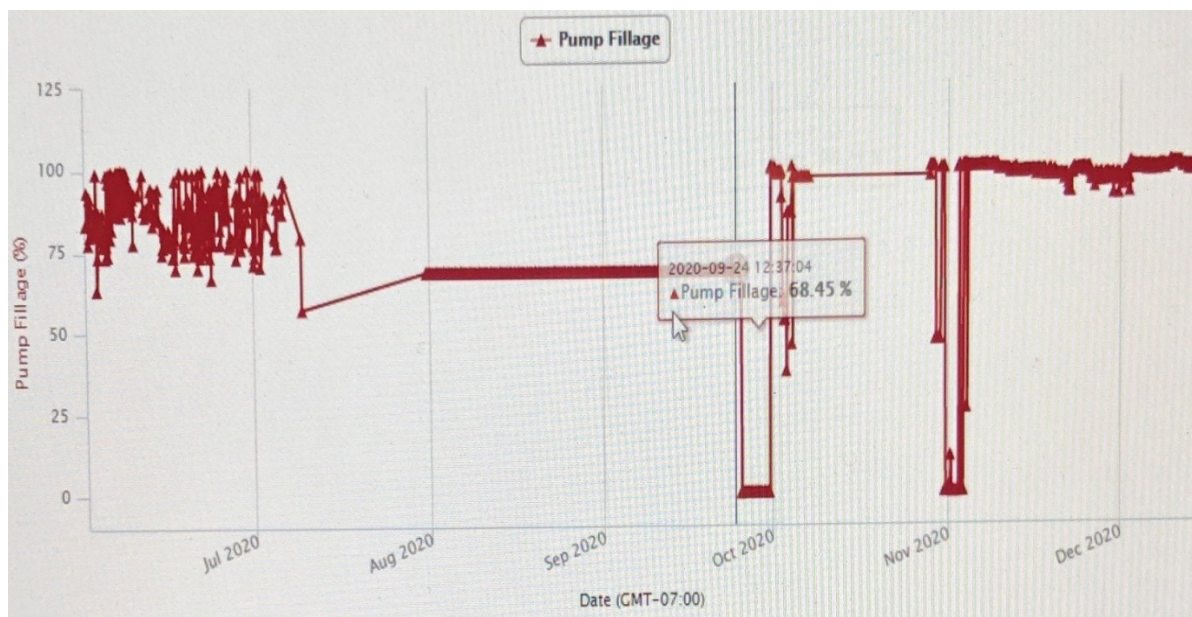
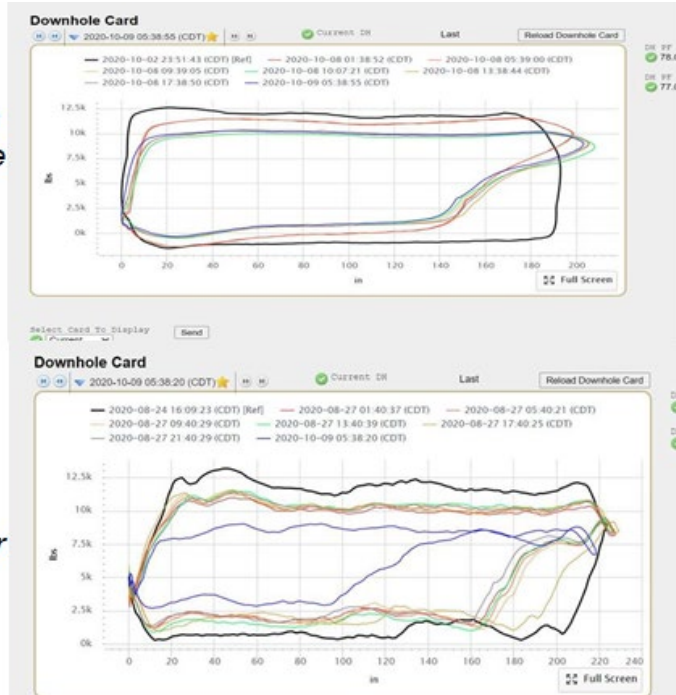


FIGURE 23 - CASE STUDY 2 – HIGH CONSISTENT PUMP FILLAGE VERSUS POOR-BOY

Complete free gas separation with the WhaleShark™



Incomplete separation with a poor-boy separator

FIGURE 24 - CASE STUDY 3 – FOAMY CONDITIONS CONSISTENT PUMP FILLAGE VERSUS POOR-BOY

Production (Gross Raw)

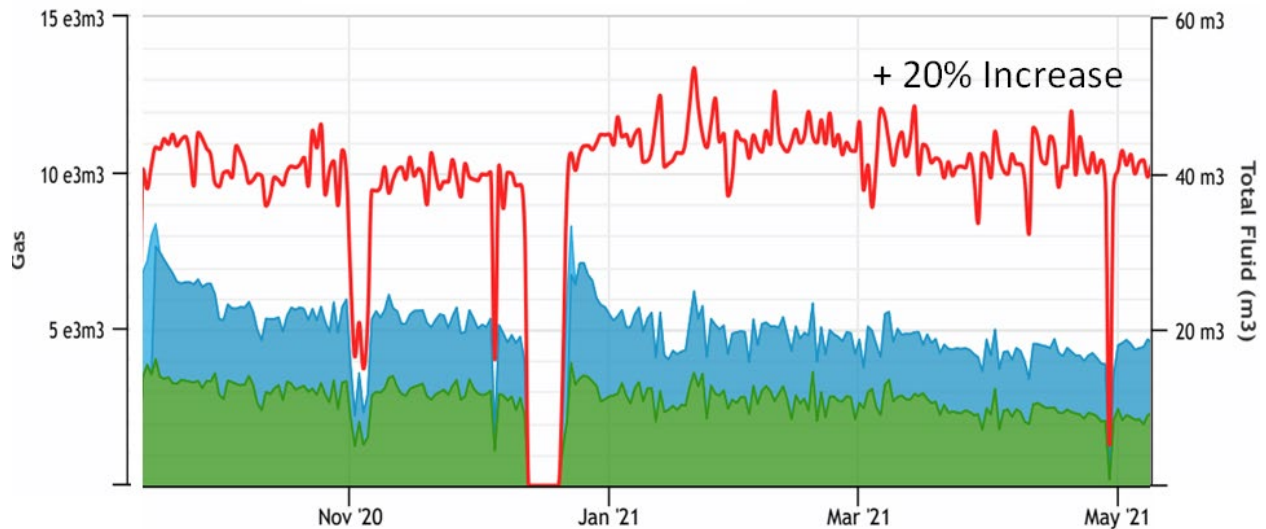


FIGURE 25 - CASE STUDY 4 – HIGH INCLINATION PLACEMENT VERSUS POOR-BOY

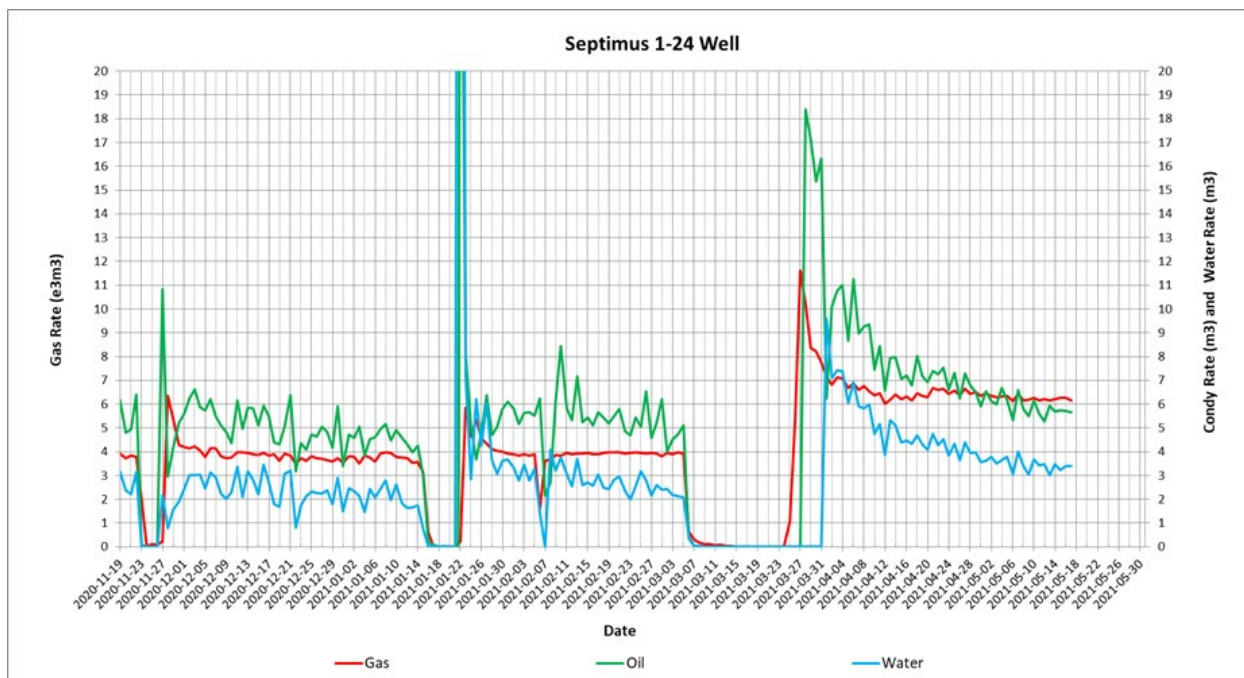


FIGURE 26 - CASE STUDY 5 – INCREASED PRODUCTION AND RELIABILITY VERSUS POOR-BOY

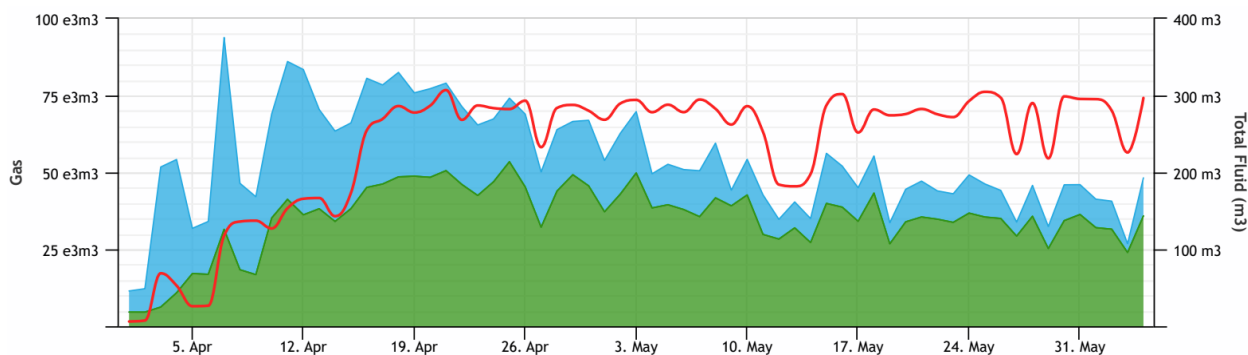
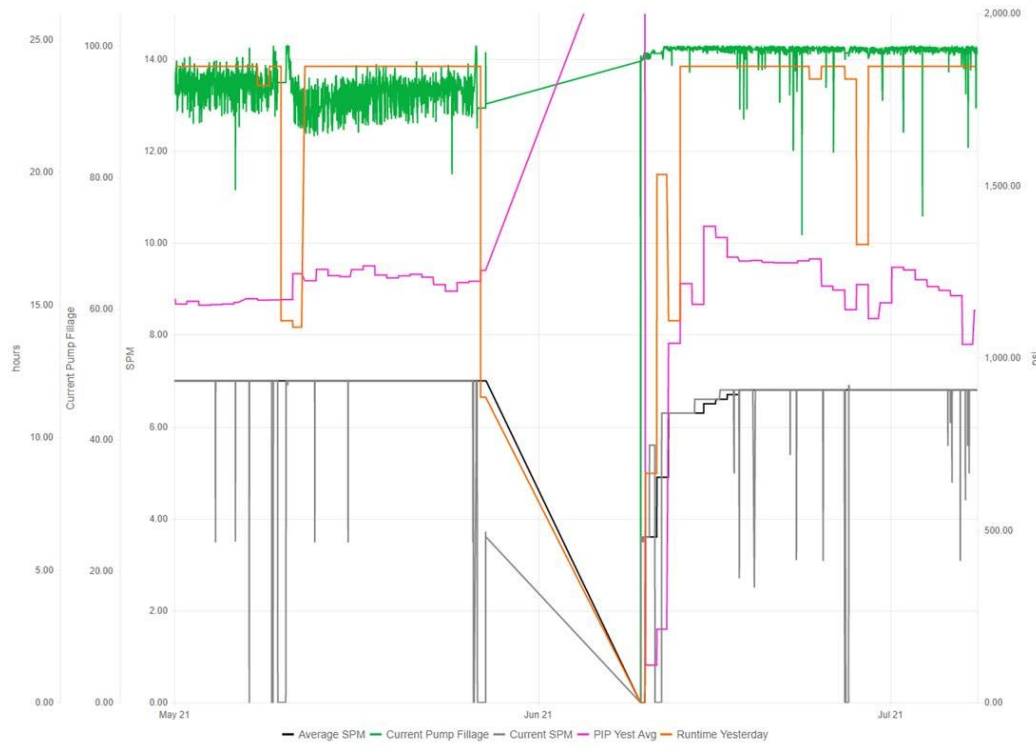
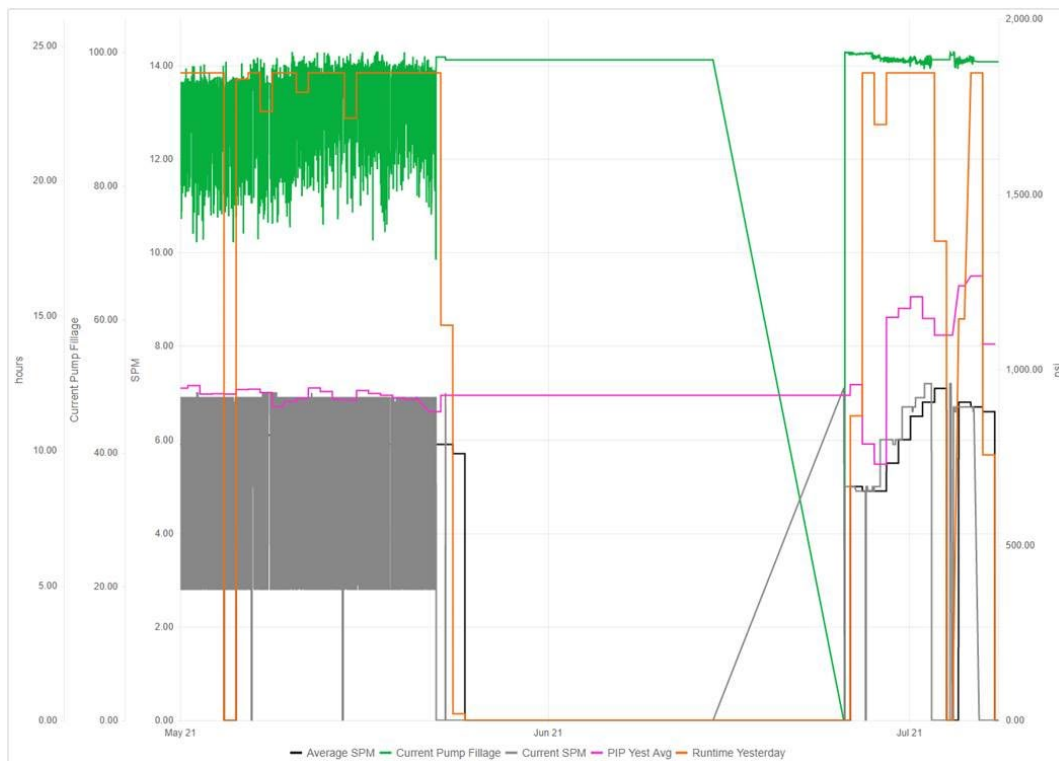


FIGURE 27 - CASE STUDY 6 – VERY HIGH RATE SEPRATION PERFORMANCE



Well 1 - Bakken



Well 2 - Bakken

FIGURE 28 - CASE STUDY 7 – HIGH CONSISTENT PUMP FILLAGE VERSUS PACKER-STYLE

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