SOLIDS SOLUTIONS FOR ROD LIFTING MODERN HORIZONTAL WELLS

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INTRODUCTION

Sucker rod lifting or pumping for horizontal wells has advanced considerably over the past few years. Advancements in sucker rod pump technologies and bottomhole assembly (BHA) components/configurations have allowed for more efficient downhole gas separation and greater production drawdowns. The unintended consequence has been an escalation of solids in the produced fluids with increased failure frequencies.

Solids control while sucker rod pumping horizontal wells is risky, complex, and tricky, especially when lowering a pump into the curve or using Extended Intake Tubing systems in the curve. An Extended Intake Tubing system is a BHA that places the pump in the vertical or near-vertical section of the wellbore, while positioning the gas separator deeper down in the curve section using multiple joints of tubing.

Laboratory and field studies confirm that gassy slug flows move solids as migrating dunes/beds along a horizontal wellbore. These dunes of solids accumulate (over weeks and months during production) in the lower portion of the wellbore's curve section. Excessive gas rate surges or spikes risk mobilization of these accumulated solids as a high-concentration solids slug, which can overwhelm BHAs and cause stuck/failed pumps.

A comprehensive system solution was deemed essential for controlling the risk of high-concentration solids slugging: advanced slug suppressing and solids separation BHAs paired with targeted operating practices. The following solution is proving effective:

1. apply operational practices to limit high-concentration solids slugs,
2. BHA designed to suppress slug flows,
3. BHA designed to handle high-concentration solids slugs,
4. pump designed to efficiently convey solids through itself with low damage risk, and
5. BHA components above the pump designed to control the risk of solids fallback.

Results from implementation of this comprehensive approach with innovative solids control and separation technologies are showing promise for improving failure frequencies and lengthening pump run life.

FIELD TRENDS IN PUMP FAILURES REVEAL THE SMOKING GUN

Solids in the produced fluid risks have escalated considerably in horizontal wells, as multistage hydraulic fracturing practices have exponentially increased the number of frac stages, the amount of frac sand being pumped, the amount of lower-quality of frac sand (namely, the amount lower-quality frac sand that can crush into finer solids particles), and the amount of finer-sized frac sand (for example, 100 mesh). Longer lateral and multi-lateral well designs have also increased the propensity for wells to have unstable and sluggy flow conditions. Nystrom's[i] research article noted that "horizontal well designs have become progressively longer and more intense in terms of proppant usage. Virtually, the entire industry has switched from high-permeability grade proppants like 30/50 to lower permeability grades such as 100 mesh." Finer frac sand solids particles and their typical size distribution range, noting 100 mesh frac sand particles are mostly larger than 120 microns and smaller than 200 microns in size

Q2 Artificial Lift Services (Q2 ALS) has an extensive pump tracking system and database – Q2-Trak™. Producers can collect and maintain their sucker rod pump data and perform statistical failure analysis. A common trend that was being recorded was that failed pumps had the barrel filled or partially filled with solids. Figure 1 shows a picture of a tear-down of a failed pump where the pump had large volumes of solids below the plunger and inside the barrel and above the standing valve.

A pump barrel filled with even a small volume of solids would prevent the pump's plunger from travelling its full distance on the downstroke – leading to a stuck pump or failed rods above the pump (from excessive buckling forces).

There is only one way that a pump can fill or partially fill itself with solids below the plunger – on the upstroke, the pump filled its barrel with a high-concentration of solids ladened fluid. So how and why did a high-concentration slurry of solids-ladened fluid arrive at the pump? Understanding, controlling, or mitigating this risk would be highly beneficial for improving the failure frequency for sucker rod pumping horizontal wells.

SOLVING THE MYSTERY OF PERPETUAL SLUGGING IN HORIZONTALS

Importantly and unfortunately, at typical sucker rod pump gas and liquid rates, flow conditions along a horizontal wellbore are always sluggy.

Alameedy etal[ii] in Figure 2 revealed that for a very broad range of superficial gas phase velocities, the flow regime can always be in a slug flow condition. But this is for the case of a straight horizontal pipe with water liquid rates above 600 barrels per day inside 4.8-inch internal diameter (ID) casing (5.5-inch by 20 lb/ft casing scenario), which is outside the typical sucker rod pumping range.

Note:[iii] superficial velocities (also called superficial flow velocity) of a phase is the velocity that phase (gas or liquid) would have if it were flowing alone through the entire pipe cross-section, with no other phases present. It is a hypothetical velocity – not the actual speed of the fluid particles, but it is extremely useful because it is easy to calculate and stays constant regardless of how the phases are distributed (stratified, slug, annular, etc.).

Kadri's[iv] research in Figure 3 research showed that very long slugs can still form at lower liquid and gas superficial velocities outside of the slug flow regime range, but there remains a large range of sucker rod pumping velocities where such large slug formation or slugging in general is not occurring. A straight horizontal pipe would likely stay stratified/wavy at typical sucker rod pumping gas and liquid rates.

So why then are horizontal wellbores commonly excessively sluggy during rod pumping?

The primary mechanism that forces horizontal wellbores to be perpetually sluggy is the wellbore's trajectory. Undulations in the wellbore's trajectory, up and down, cause **terrain-induced slugging**. All the useful flow regime pattern maps have been derived in straight pipe flow loops and they do not consider pipe undulations. It would be nearly impossible to flow pattern map the infinite combinations of wellbore undulations.

There are essentially two forms of gas-liquid slugging:

1. Hydrodynamic – slugging when flow conditions are within slug flow regime as per the flow pattern maps of superficial gas and liquid velocities
2. Terrain-Induced – slugging caused by undulations of the wellbore's trajectory

Even though wells are labeled "horizontal," they rarely stay perfectly flat/straight; small elevation changes (i.e., undulations up and down) from drilling, geosteering, or following reservoir contours create low points and slight inclines. These undulations trap liquids and allow gas pockets to form, leading to intermittent, cyclic slug flow rather than steady production or lower superficial gas/liquid velocity stratified flow. An undulation blocks the gas path with liquid, builds upstream pressure, to the point where the liquid gets periodically swept out as large slugs of liquid. This is complex, as each undulation impacts slugging severity.

Ragab [v] in Figure 4 illustrated pipeline terrain-induced gas-liquid slugging. Terrain undulations in the horizontal wellbore (which is a pipeline) push the flow system into terrain-induced gas-liquid slugging at much lower gas and liquid velocities as compared to hydrodynamic gas-liquid slugging (i.e., the slug flow regime).

This terrain-induced slugging mechanism is triggered when gas momentum is insufficient to continuously push the liquid over the undulation's uphill slope sections without liquid blockage. Importantly, it occurs over a much broader velocity range than the hydrodynamic slug flow regime – at much lower and higher superficial gas and liquid velocities (depending on undulation severity and pipe diameter). Yin's[vi] research detailed the superficial velocity ranges expected for terrain-induced slugging:

- superficial liquid velocity (Usl): from 0.01 m/s up to 0.5 m/s.
- superficial gas velocity (Usg): from 0.1 m/s up to 3 m/s

These superficial liquid and gas velocities translate into production rates that are within the typical sucker rod pumping range inside 4.8-inch internal diameter by 5.5-inch by 20 lb/ft casing scenario:

- from 60 to 3,000 barrels/day liquid
- from 65 to 1,900 Mscf/day gas (at 250 psig)

Slugging severity can be compounded and worsened. A Toe-up horizontal wellbore geometry can be the worst-case scenario for severe slugging. A toe-up trajectory acts like an unstable gas trap, where the trapped gas periodically releases violently around the curve as a large-amplitude slug.

The wellbore's curve section also worsens or amplifies slugging – the curve induces severe terrain-induced gas-liquid slugging. As the wellbore inclination increases from horizontal toward vertical, gravity becomes increasingly dominant and greatly influences gas-liquid separation. Gravitational separation effects in the curve promote instability, transitioning the flow conditions to slug flow much earlier (i.e., the slug flow regime's superficial velocity range broadens). Slugs from the horizontal get amplified by merging and growing larger in the curve, before they enter the vertical section. Slugs amplified in the curve then arrive in the vertical section as large, irregular bursts. Often flow at the top of the curve will be fully intermittent, characterized by highly cycling pump fillage conditions (i.e., when large gas slugs flow past the downhole gas separator). This is why placing a gas separator at the top of the curve can be problematic, as that is where slugging is the most severe.

This is also why BHA designs like Extended Intake Tubing systems (placing gas separators deeper in the curve) aim to mitigate slugging by reducing the curve's terrain slugging amplification effect and smoothing of the flow conditions. Nagoo and Saponja et al[vii], in Figure 5 proved that wellbore slugging could be significantly reduced by installing a velocity string through the wellbore's curve section (i.e., small internal diameter pipe that increased the superficial gas phase velocity to the point that liquids were lifted and slugging was suppressed in the curve).

Another factor that impacts slugging is the apparent viscosity of oil and water mixtures. Lv et al's[viii] experiments showed that oil and water mixtures exhibit higher apparent viscosities than either water or oil by themselves. Lv showed that the apparent viscosity can be 350 centipoise at a 65 percent water cut with lighter oils. The impact to gas and liquid flow conditions is that the higher the apparent viscosity, the more frequent and larger gas-liquid slug flows become.

It can be concluded that flow along horizontal wellbore will likely be perpetually sluggy over the well's entire production life.

GASSY-SLUGGY FLOWS TRANSPORT AND HAZARDOUSLY ACCUMULATE SOLIDS AT THE BASE OF THE WELLBORE CURVE

Typical sucker rod pumping rates have liquid velocities in a horizontal wellbore that are not high enough to continuously disperse, suspend, and transport solids. So how and why are sucker rod pumps failing due to solids, especially if they are positioned above the curve's kick-off point up in the vertical?

In a horizontal wellbore, laboratory and field studies confirm that when liquid velocities are too low to fully suspend and transport the solids, gas-liquid slug flows transport solids as migrating dunes/beds. The previous section disclosed that horizontal wellbore trajectory undulations are the root cause for perpetual wellbore gas-liquid slugging and therefore solids transportation.

Leporini et al[ix] in Figure 6 showed that at relatively low liquid velocities, solids form dunes/beds that are transported along the horizontal wellbore by gas-liquid slug flows. In other words, for sucker rod pumping, solids will always be migrating as concentrated dunes/beds along a horizontal wellbore.

Figure 7[x] details superficial liquid velocities required to fully suspend and transport solids – for example, above 1,000 barrels/day for a 4.8-inch internal diameter casing (5.5-inch by 20 lb/ft casing scenario). The figure also shows that at lower liquid rates and velocities, solids are transported as migrating dunes/beds.

This solids transportation process is called saltation and Huque[xi] in Figure 8 illustrates the mechanism. Gas-liquid slug flow is responsible for lifting solids particles from the dune/bed surface and transporting them to the subsequent dune/bed downstream. The high-velocity liquid slug body (often 2 times the mixture velocity) creates intense turbulence, shear stress, and wave action at the front and within the slug, temporarily scouring solids from enhanced fluid drag, lift forces, and turbulent bursts. This disrupts and transports dunes more effectively than in non-slug flow conditions. As such, the primary means for solids transport is saltation associated with gas-liquid slug flows.

Slug flow continuously migrates solids dunes and beds along the horizontal wellbore. However, in the wellbore curve section, gravity begins to limit further migration, leading to progressive local accumulation and stacking of dunes over weeks and months of production. Zahn's[xii] research explains that for the typical solid particle sizes experienced during sucker rod pumping (post-fraccing at 100 to 400 micron), the solids settling angle of repose is approximately 60 degrees inclination. Figure 9[xiii] shows that the solids will effectively fallback and bridge at 65 degrees inclination when the solids settling angle of repose is 60 degrees. Therefore, solids dunes/beds will accumulate and stack out on top of each other at wellbore inclinations in the curve greater than the solids settling angle of repose (i.e., between 65 and 90 degrees wellbore inclination).

Figure 10[xiv] shows the localized solids accumulation process, where a downhole camera recorded solids dunes/beds migration that locally accumulated or stacked out on top of themselves.

Localized accumulations of solids upstream of the BHA are highly concerning and hazardous for damaging a sucker rod pump. The well effectively "loads a gun" of accumulated solids below the BHA. If this gun is allowed to be fired as a high-concentration solids-slug, the sucker rod pump can catastrophically fill itself with solids. Kimery[xv] explained that it is very common for unconventional horizontal wells to possess inconsistent sluggy flows and it is these sluggy inconsistent flows that transport solids to the separator as high-concentration slurries.

EXCESSIVE GAS RATE SURGES AND SPIKES ULTIMATELY FAIL PUMPS

The previous sections discussed in detail that gas-liquid slug flows within a horizontal wellbore during sucker rod pumping transport solids (even at low liquid rates) in the form of dunes/beds. These solids dunes/beds migrate in the direction of flow and then accumulate or stack out at the base of the wellbore's curve.

Any excessive gas rate surge or spike can generate high instantaneous liquid velocities within the slug body, easily exceeding the solids suspension and transport velocity. As a result, the accumulated solids are picked up by the high-velocity stream and transported as a dense, high-concentration slurry or "solids slug, often with high solids volume fractions of 10–40%[xvi] or greater in the front of the liquid slug.

The high-concentration solids slugs risk overwhelming the BHAs ability to handle solids, which leads to stuck and failed pumps. It is this process that fills or partially fills a sucker rod pump with solids and fails it.

What is interesting but also concerning, the total volume of solids does not have to be excessive. A high-concertation solids slug only needs to be large enough to partially fill a pump barrel (below its plunger) and then subsequently prevent the plunger's full range of travel on downstroke – a cup of coffee volume of high-concentration solids can fail a pump. This also helps to explain why producers get caught up in a costly negative virtuous cycle of failed pumps followed by major workovers with horizontal wellbore cleanouts, yet only to recover a small volume of solids (for example, by a venturi bailer).

The most likely causes of excessive gas rate spikes or surges while sucker rod pumping:

1. start-ups after shutdowns (i.e., stops and starts, well cycling),
2. rapid changes in pump speed,
3. rapid changes in casing pressure at surface, and
4. pre-existing solids bridges releasing

Industry literature[xvii] states that gas can be 100 times (or more) more mobile than liquid (oil or water) in a petroleum reservoir. When a well is shut-in and is static, pressure builds in the reservoir near the wellbore. When the well is restarted, the buildup of stored pressure and energy initially allows mostly gas to enter the wellbore since gas is more mobile in the reservoir – forming a high gas rate surge or spike. The same mechanism occurs when the producing bottom hole pressure is rapidly lowered (for example, rapid changes in pump speed and/or casing pressure).

To manage the risk of a high-concentration solids slug or slurry reaching a BHA, the identified causes must collectively be controlled.

EXTENDED INTAKE TUBING BHA'S OR PLACING PUMPS INTO THE CURVE CAN INCREASE PRODUCTION BUT ALSO SOLIDS RISKS

Sucker rod lifting or pumping for horizontal wells has advanced considerably over the past few years. Advancements in sucker rod pump technologies and bottomhole assembly (BHA) components/configurations have allowed for more efficient downhole gas separation and greater production drawdowns. The unintended consequence has been an escalation of solids in the produced fluids with increased failure frequencies.

An Extended Intake Tubing or Extended Dip Tube system is a BHA that places the pump in the vertical or near-vertical section of the wellbore, while positioning the gas separator deeper down in the curve section using multiple joints of tubing. Figure 11 shows an example of this BHA configuration. Saponja and Kubacak et al[xviii] discussed this system and how they can successfully increase the production drawdown (i.e., achieve lower producing bottom hole pressures), but also that they suppress slugging in the curve. The deeper a separator is placed in the curve, the less ability the curve has for it to form gas-liquid slugs (reduces terrain-induced slugging, as the severity of the terrain's vertical distance is reduced proportional to the separator's depth). Figure 12 shows a positive result, with increased production and stable pumping parameters over a long period of time. Figure 13 shows that with reduced terrain-induced slugging in the curve, the annular fluid can be drawn all the way down to the separator (at 45 degrees inclination) while still feeding the pump up in the vertical will high consistent pump fillage.

An example BHA of a high inclination sucker pump placement in the curve can be seen in Figure 14. A deeper in the curve placed pump and gas separator can increase the production drawdown and therefore uplift production (i.e., achieve lower producing bottom hole pressures). A deep in the curve placed gas separator provides similar suppression of terrain-induced slug flow as for the Extend Intake Tubing system. In figure 15, Saponja and Kubacak et al[xix] explained the difference in production parameters for the two different "in the curve" BHAs, with both exhibiting reduced terrain-induced slug flow conditions.

From a gas-liquid slug flow perspective, reduced slugging should correlate with less solids risks. But this has not been the case. It has been widely reported that both BHA systems have increased solids related issues. This increase in solids risk is likely due to lower bottomhole producing pressures expanding the gas volume, increasing the gas rate, which collectively increases the superficial gas velocities in the horizontal wellbore. An increase in superficial gas velocity increases the wellbore's ability to transport solids. Higher gas velocity increases the gas-liquid mixture velocity and interfacial shear on the liquid phase, which reduces the critical solids deposition velocity (the minimum liquid velocity needed to keep solids moving). In other words, for the same liquid rate, higher gas velocity allows solids to be transported at lower liquid velocities. Solids dunes/beds advance faster during slug passages due to the higher local liquid velocities sweeping the solids over the dune/bed crest and depositing them on the lee side.

In conclusion, producing at lower bottomhole pressure increases solids transport and results in more rapid solids accumulations at the base of the wellbore curve. This in turn increases the risk of gas rate surges and spikes transporting high-concentration solids slugs to the BHA.

In addition, solids separation becomes more challenging at higher wellbore inclinations, as all downhole solids separator rely on gravity for separation. Consequently, the ability to handle and control solids in the curve is also compromised or becomes limited. This is discussed in greater detail in the following section.

CHALLENGES HANDLING HIGH-CONCENTRATION SOLIDS SLUGS DOWNHOLE

Downhole solids control and separation while sucker rod pumping horizontal wells is risky, complex, and tricky. Ideally, if downhole gas and solids separation is 100% efficient, pure liquid would feed the pump, and no solids would damage the pump or get trapped in the tubing string above the pump (causing pump sticking events). Unfortunately, achieving this has been a considerable challenge. Consequently, it is highly likely some gas and solids will remain in the fluid stream as it enters the pump, and solids will accumulate in the tubing string above the pump.

For sucker rod pumping of horizontal wells, the previous sections concluded that solids will most likely arrive at the BHA as high-concentration masses / slugs, that:

- risk overwhelming of solids separators
- risk rapid plugging of sand screens
- risk sucker rod pump damage and/or stuck pumps
- risk solids being carried through BHA and pump and into the tubing string above the pump, where stoppages can allow these solids to fall back or settle on top of the pump (resulting in a stuck pump)

For a sucker rod pump downhole solids separator to be efficient and effective, it must:

1. separate solids from a high-concentration slurry,
2. separate solids over a highly variable rate range,
3. separate solids in a high apparent viscosity oil and water mixture,
4. operate efficiently at all wellbore inclinations, and
5. be cost effective…

Saponja and Conyers et al[xx] discussed that there are three forms of downhole liquid-solid separators commonly used for rod pumping and none of them have effectively solved downhole solids separation:

1. Gravity
2. Cyclonic-Gravity (desander)
3. Filtering Screens

When a high-concentration slurry or slug of solids reaches a downhole solids separator, the separator can easily be overwhelmed, resulting in solids carry-over to the sucker rod pump. How a high-concentration solids slurry affects the efficiency of a downhole solids separator in gas-liquid slug flow conditions has not been extensively studied in literature. But it should be apparent to the reader that a significant reduction in separation efficiency occurs as solids concentration in the liquid slurry increases.

Rowland[xxi] explained in Figure 16 that sucker rod pump plunger velocities during the upstroke stroke are highly variable. He showed how a pump plunger's upstroke rapidly accelerates, starting from zero (0) inches per second to eighty (80) inches per second in just one second. For example, the pump jack at surface can be one third of the way up on its upstroke before the downhole pump's plunger starts moving (due to sucker rod string stretch and sucker rod friction). Then the plunger's velocity "slingshots" under extremely high acceleration to a peak plunger velocity. It is fundamental to understand that the plunger's velocity profile and intake liquid rate can vary from zero (0) to over four (4) times the average each pump stroke. This importantly points out, for example, that for a well with a sucker rod pump producing an average 200 bbls per day liquid, an instantaneous peak liquid rate entering the pump can be 800 barrels per day (each pump stroke). At six (6) strokes per minute, the pump's liquid intake rate goes for zero (0) to

800 barrels per day and then back to zero (0) in five (5) seconds. Such high variable rates amplify solids risks. To this end, the technical engineering consideration and challenge for downhole solids separation design is that the sucker rod pump's intake liquid rates vary over an extensive rate range each pump stoke.

Gravity-based downhole solids separators (typically poor-boy type) are challenged by smaller solids particles since they are more easily carried in a fluid stream. Intermezzo[xxii] showed solids terminal settling velocities as a function of solids particle size. Smaller solids particles settle at much slower velocities and therefore can be carried or suspended at lower liquid velocities than larger solids. Both the downward and upward liquid velocities outside and inside a poor-boy separator's dip tube range widely each pump stroke – from zero (0) feet per second to over sixteen (16) feet per second (500 millimetres per second), which is greater than the solids settling velocity of most particle sizes encountered in oil and gas wells. As such, some solids will always be carried through a poor-boy separator into and above the sucker rod pump.

In short, downhole cyclonic solids separators (e.g., desanders) work well for trace or steady solids in the produced fluids, but they are easily overwhelmed by the intermittent, high-concentration slurries common in sluggy horizontal wells. Downhole cyclonic solids separators can struggle to separate finer solid particles. Martins[xxiii] research in Figure 17 showed that downhole cyclonic-gravity separators inefficiently separate solids particles smaller than 200 microns. Shaffee[xxiv] explained that downhole cyclonic separators designed for solid-liquid separation are unable to achieve their intended separation efficiency especially if any gas phase is present in the fluid stream. In other words, sizing of a cyclonic separator for solids-liquid separation is very challenging and will likely underperform if any gas volume fraction is present in the fluid stream – a condition that is highly likely during sucker rod pumping, as no downhole gas separator has proven able to separate all the gas from the liquid (especially foamy entrained gas). With respect to cyclonic separator handling of solids particle size distribution and range, Shaffee concluded that they will not be able to separate the entire range of sand in the hydrocarbon stream, especially smaller sized particles.

Shaffee further explained that cyclonic separators designed for solids-liquid separation underperformed during "varying inlet stream upstream conditions". In this respect, Shaffee observed that during a well flowrate decrease the required flow will fall below optimum cyclonic separation conditions leading to sand carryover to the outlet stream and flow stability (i.e., liquid slugging negatively affects cyclone efficiency). Such variable inlet conditions are obviously present during rod pumping. Shaffee showed that only 16% of their cyclonic separators were online and with a sand separation efficiency of "at best" around 50%. The root cause of this low efficiency being is an inability for separators to handle varying inlet rates and a lack of adequate turn down ratio. A cyclonic separator needs a threshold level of centrifugal force from the incoming feed flow velocity. If inlet rates are predictable and consistent, cyclonic separators should exhibit high performance for solids-liquid separation. If inlet rates into a cyclonic separator are too high, erosion (reduced reliability) and excessive turbulence (solids carry over into the overflow stream) risks arise.

Langbauer's[xxv] research showed that downhole cyclonic separators are engineered to handle low concentrations of solids volume fractions in the liquid phase. Rawlins[xxvi] defined this limit as less than 5% solids volume fraction in the liquid phase. It was discussed previously that gas rate surges and spikes likely form high-concentration solids slurries of 10-40% solids volume fraction in the liquid phase. Therefore, downhole desanders are not designed to handle high-concentration solids slugs/slurries.

A downhole cyclonic separator has reduced performance in the presence of high apparent viscosity oil/water mixtures (which is what we pump!). Juan[xxvii] detailed that even though the produced oil is "light" (low viscosity), stable oil-water emulsions common in horizontal-well production can exhibit apparent viscosities many times higher than either phase alone (often 10–100+ cP or more, depending on water cut, shear history, and emulsifiers). This dramatically degrades the centrifugal/vortex separation mechanism that downhole desanders rely on. To this end, it is highly apparent that cyclonic separators for sucker rod pumping conditions in horizontal wells do not possess the ability to operate efficiently over the flow rate range expected during a sucker rod pump intake stroke nor can they operate efficiently in presence of a high solids concentration slurry.

Filtering screen solids separation solutions face a high risk of plugging and/or scaling off. Filtering of solids particles inevitably leads to a blocked filter. They often are designed with a bypass pressure differential valve that opens in the event the screen becomes plugged or the differential pressure across the filter screen exceeds some level. Bypassing leads to solids carry-over in the fluid stream to the sucker rod pump. In the presence of a high-concentration solids slurry, rapid plugging or "blinding off" of the screen is highly likely, resulting in a high-concentration solids slurry catastrophically entering the pump.

It is concluded that all existing forms of downhole solids separation, by themselves and A a singular downhole component, are highLY challenged and likely ineffective in the presence of a high-concentration solids slurry or slug, in high apparent viscosity oil/water mixtures and under highly variable liquid rates.

<u>COMPREHENSIVE SYSTEM SOLUTION FOR CONTROLLING SOLIDS RISKS</u>

A comprehensive system solution was hypothesized as being deemed essential for controlling the risk of high-concentration solids slugging: an advanced slug flow suppressing and high-concentration solids separating BHAs, paired with targeted operating practices to limit high-concentration solids slugging.

The following solution is proving effective:

1. Apply operational practices to control and limit formation and transportation of high-concentration solids slugs:
    a. adopt and implement a preventative maintenance casing flush program, especially after shutdowns and workovers,
    b. employ operational practices and wellhead control equipment that avoid excessive gas rate surging and spiking, and
    c. employ rod pump controller logic that suppresses slug flows

2. BHA designed to suppress slug flows.
3. BHA with components designed to handle and separate solids (at any wellbore inclination) when faced with a high-concentration solids slug/slurry contained within a high apparent viscosity oil/water mixture.
4. Pump designed to efficiently convey solids through itself with low damage risk.
5. BHA above the pump designed to control solids fallback risks.

OPERATIONAL PRACTICES TO CONTROL AND LIMIT FORMATION AND TRANSPORTATION HIGH-CONCENTRATION SOLIDS SLUGS

It was discussed in a previous section that perpetual wellbore slugging continuously migrates solids dunes/beds and then they accumulate at the base of the wellbore's curve section. Disrupting and/or limiting this process of solids accumulation can be achieved by adopting preventative maintenance operational practices.

Recommendation 1: Implement a proactive and preventative solids risk management casing flush program. Apply casing flushes using produced water (if possible) once a month (or as the well dictates and likely required indefinitely), with the intention to disperse solids accumulated in the curve and displace them as far back out into the horizontal wellbore as possible (out of arm's way).

Procedure:

a. Prior to installing a new BHA, always pump multiple casing flushes while OOH with the tubing and BHA.
b. It is recommended to pump high-rate casing flushes in three (3) stages. At a constant liquid rate and only pumping a single stage flush, solids quickly form dunes that allow the liquid to flow over the dunes, reducing solids displacement efficiency. This is why sluggy flows are efficient at transporting solids. It is more effective to pump multiple disruptive flush stages to bust-up these dunes and efficiently transport solids. The more disruptive the pump rates/stages, the more effective.
c. Pump multiple smaller stages (at least 3) of 100-200 bbls per stage (or as well conditions/field experience dictate). Pump at as high of rate as possible for each stage (within surface treating pressure limits). Stop for 30 minutes between stages to confirm the well is on a strong vacuum or as well dictates.
d. Apply casing flushes once a month during production (or as the well dictates and likely required to be repeated indefinitely), knowing that solids will be re-accumulating at the base of the wellbore's curve. These casing flushes can be performed with or without the pump jack running.

Recommendation 2: Implement a proactive produced water slip streaming program. Recirculate produced water back down the casing-tubing annulus, so the total liquid volume entering the BHA and pump is maximized to the available capacity of the sucker rod pumping system (maximized pump stroke/length rate for the pump size). This dilutes the solids concentration in the produced fluid emanating from the horizontal wellbore, helps to disperse high-concentration solids slugs, keeps solids suspended through the pump and allows for more solids to be suspended/transported to surface (avoiding solids accumulating in the tubing above the pump and solids fallback risk above the pump. This method can be continuous or periodic, as the well dictates and to limit stress on the rod pumping system. Note, high gas rates may not allow this option, as liquid could be flowed up the casing-tubing annulus.

It was discussed in a previous section that the root cause of high-concentration solids slugs reaching a BHA is from excessive gas rate surges and spikes. The most likely causes of excessive gas rate spikes or surges:

1. start-ups after shutdowns (i.e., stops and starts),
2. rapid changes in pump speed,
3. rapid changes in casing pressure at surface, and
4. pre-existing solids bridges releasing

There are operational practices that can control and limit excessive gas rate surges and spikes during production. The genesis of these practices is to do things gently-slowly-patiently, as horizontal wellbore flow/production responds or reacts very slowly to changes. Changing parameters too quickly or too rapidly leads to uncontrollable flow instabilities and a high risk of excessive gas rate surges and spikes. The challenge with a shut-down interruption is the well now needs to be restarted from a static state and transitioned to a dynamic producing/pumping state. This is the timeframe when excessive gas rate surges and spikes most often occur. Many and most pump failures can be correlated back to a recent shut-down.

Recommendation 3: apply operational practices that can control and limit excessive gas rate surges and spikes during production.

Procedure:

a. During pumping, always maintain casing pressure above 100-150 psi (or lower if well slugging conditions allow). Compressing the gas downhole avoids rapid expansion of gas bubbles/slugs as they travel through the wellbore's curve. If possible, install an adjustable choke or regulator valve on the casing outlet for more effective casing pressure control.
b. If a shut-down occurs, consider casing flushes (as above) prior to re-starting.
c. If a shut-down occurs, close the casing valve to prevent high gas rate spikes upon restarting. Re-start pumping and allow the casing pressure to build, but do not exceed a pressure that forces the annular fluid level all the way down to the gas separator. Once the well begins stabilizing,

typically over several days, slowly reduce casing pressure to line pressure. Do not rapidly adjust casing downward pressure at any time.

d. If a shut-down occurs, start the well back up at a fixed controller speed based on the average speed prior to the well shutting down. Rod pump controller settings that “chase higher fluid rates” with a high high-speed set point can draw the well’s annular fluid level down very quickly and consequently encourage a high gas rate surge or spike. Always “pump through” the expected initial excessive gas slugging at the fixed speed, as speeding up and slowing down in reaction to unstable pump fillage can worsen slugging. Once the well stabilizes, place the well back into controller mode and settings as prior.
e. Rod pump controller speed changes in pump stroke rate should be gentle and in very small increments to suppress slug flows and avoid inducing high gas rate surges and spikes. Do not increase or decrease high/low speed set points by more than 0.1 SPM at a time and only make one speed change per day. Accordingly, adjust the rod pump controller to make speed changes very slowly and recommend that the rate of change of speed setting be 0.1%-0.5% per pump stroke (note: most rod pump controller defaults are set way too high at 10% and react too fast). Keep the difference between high and low speed set points as close together as possible (a wide range will likely lead to unstable over-controlling “chasing its tail” with an excessive amount of speed changes – creating unstable downhole flow conditions and worsening of slugging.

BHA’S DESIGNED TO SUPRESS SLUG FLOWS

BHA’s can be configured to suppress and control slug flows. Suppressing slug flows has the benefit of reducing solids transport along the horizontal wellbore and the rate that solids accumulate at the base of the curve.

As discussed previously, the wellbore’s curve section experiences severe terrain-induced slugging. The deeper a separator is placed in the wellbore’s curve, the less ability the curve has for it to form gas-liquid slugs (reduces terrain-induced slugging, as the severity of the terrain’s vertical distance is reduced proportional to the separator’s depth).

As discussed previously, use of Extended Intake Tubing system BHA’s will suppress slugging (see Figure 12). Figure 18 shows that adding additional mud joints to the bottom of a separator such that they are extended as deep as possible into the curve section can suppress slugging. Terrain-induced slugging severity is a function of the superficial gas phase velocity. The pipeline industry has determined anecdotally and empirically that there is unstable region in the slug flow regime that will have excessive and severe intermittent slugging. If the superficial gas phase velocities are increased by reducing the cross-sectional area of the flow path (i.e., running mud joints deeper in the curve creates an annularflow path with higher superficial gas phase velocities), this unstable region can be avoided, and slugging can be suppressed in the curve. Note, there is an upper limit for applying slug flow suppression superficial gas phase velocities, generally no greater than 3.0 m/s (10 feet/second) has been empirically determined by Oilify's research.

<u>BHA WITH COMPONENTS DESIGNED HANDLE HIGH-CONCENTRATION SOLIDS SLUGS AND SEPARATE SOLIDS</u>

Extensive previous discussion and research explained that existing downhole solids separators are challenged by high-concentration solids slugs, apparent oil/water mixture viscosities, variable liquid rates, and operability at higher wellbore inclinations. Fundamentally, existing downhole solids separator designs are not engineered for such challenges. Most were designed from results determined in steady state flow loops using water, which is not representative of the conditions likely to be encountered downhole while sucker rod pumping. Basing a design off tests conducted with water and/or under steady state flow conditions can be highly misleading.

In addition to BHA's designed to control and limit slugging, three new patent-pending BHA technologies have been developed and field implemented over the past 18 months. They have been engineered to work in combination with each other or stand alone, depending on well requirements. A novel methodology was conceived for all three based on a hypothesis that single-stage solids separation solutions are too limiting and that sequential solids control with multi-stage solids separation would resolve the challenges.

A solids control and separation process sequence was conceptualized:

1. firstly, separate gas from the solids-laden liquids, as gas imposes high fluid velocities and turbulence which makes liquid-solids separation much more difficult and costly, then,
2. secondly, "bust up" and disperse high-concentration solids slugs, and then
3. finally, separate solids from the liquid for containment out of harm's way (at all wellbore inclinations).

New Technology #1 – the SharkGUT™ high inclination multi-stage solids slug busting separator

The SharkGUT™ was designed to operate at high wellbore inclinations greater than 65 degrees (beyond the solids settling angle of repose). It is very common in Canada to place pumps and separators at high inclinations deep in the curve, all the way to 90 degrees. Frequent solids-related pump failures established a need for high inclination solids separation.

The design challenge was how to separate solids inside mud joints below a gas separator when they are placed beyond the solids settling angle of repose. The initial concept was "borrowed" and adapted from mining technology. Gold sluicing solids separation (i.e., the sluice box) is relatively simple and effective process that entails flowing solids-laden liquid over the top of multiple sequential segmented weirs. Weirs act as step-like barriers or raised sections across the bottom of the sluice box, creating controlled flow disruptions for gravity separation of solids (and gold!). Solids containment chambers formed between each successive weir function to separate and contain the solids. Liquid is forced to "climb" over the top of each weir, promoting solids gravity settling as the liquid travels upwards (against gravity forces) and slows down prior to flowing over the top of the weir.

A design note is that liquid velocities through a weir-based system are limited to being below the velocity that would suspend and transport solids. Each weir also arrests and blocks dune/bed migration, a key engineered feature for containment of solids out of harm's way. Each subsequent weir repeats the process, providing multiple stages of separation.

A major technology breakthrough occurred during the SharkGUT initial field trials. Recorded performance was better than expected, as pump run lives improved multiple times better than previous. It was discovered that the multiple sequential weirs were "busting up" and dispersing the high-concentrated solids slugs. So even if solids were not fully separated from the liquid, solids that carried over to the pump were dispersed/diluted, preventing the pump from being filled or partial filled with solids during an upstroke – it prevented stuck pumps. It made it easier for the pump to carry the solids through itself.

Figure 20 shows a BHA diagram with SharkGUT inserts installed in the mud joints below the gas separator (at high wellbore inclination). Figure 20 shows an engineering drawing and a rendering of the SharkGUT inserts inside a mud joint with solids being captured between the weirs. They insert into standard EUE tubing mud joints and connect directly to the base of a gas separator's pump intake dip tube. Constructed from a 316 stainless steel tube and Viton or FKM weirs (controls the risk of hydrocarbon-induced swelling), it offers excellent resistance to corrosion and H_2S.

By extending the SharkGUT inserts downward into the mud joints, the flow path for the gas-separated solids-laden liquids is downward along the annulus formed by the inserts and across the weirs (which have gravity oriented to the low side of the mud joint's internal diameter). High-concentration solids slugs are busted up and dispersed, with most of the solids being separated/captured in the chamber space between the multi-staged weirs. Multiple SharkGut inserts can be connected (standard NPT threads) together to extend the assembly into several mud joints for greater solids separation capacity. Liquids then turn the corner upwards inside the SharkGUT's tube and onward through the gas separator's pump intake dip tube to the pump.

While running the BHA in the wellbore and when it reaches high inclinations, gravity self-orients the inserts and weirs to the low side within the mud joints – see Figure 21. Figure 22 shows a picture of SharkGUT manufacturing (19 weirs are installed on each 20-foot-long insert). Figure 23 provides detailed insert specifications for the various mud joint tubing sizes.

Flow loop testing with water confirmed operability and was useful for determining the optimal spacing distance between each weir for maximizing solids volume containment yet still being an efficient solids separator. Placing the weirs too close together causes the turbulence immediately downstream of each weir to scour and re-suspend settled solids, allowing them to be carried over to the subsequent weir and therefore undesirably limiting overall solids containment. See Figure 24, showing pictures from a flow loop test where a high-concentration solids slug was busted-up-dispersed-diluted. Solids are therefore effectively being captured inside a mud joint that is lying at inclinations beyond 65 degrees. Figure 25 shows solids being contained behind a weir. It is estimated the solids containment capacity is approximately 30-40% of the internal volume of a mud joint.

New Technology #2 – the MudShark™ multi-stage solids slug busting separator for inside Extended Intake Tubing's tubing systems for when placed at wellbore inclinations from 65 degrees to vertical.

With Extended Intake Tubing systems rapidly becoming commonplace as a standard BHA configuration for sucker rod pumping horizontal wells, higher inclination placement of the gas separators also means the solids separators are placed at higher inclinations. The consequence of achieving more production drawdown (i.e., lower producing bottomhole pressures) has been an increased risk of solids and reduced solids separator performance (i.e., increased failure frequencies). An improved solution was needed to safeguard sucker rod pumps.

Oilify conceptualized an inline multistage solids separation solution that would be installed inside the Extended Intake Tubing system tubing joints. Figure 26 shows a BHA with the MudShark solids separation solution contained within the Extended Intake Tubing system tubing joints.

With a common practice of running 10 to 15 tubing joints in an Extended Intake Tubing system (above the solids settling angle of repose wellbore inclinations), the resulting large tubular volume presented a valuable opportunity to utilize this space for solids separation and containment. At the same time, multi-stage solids separation technology could be adapted to effectively bust up and disperse high-concentration solids slugs/slurries.

The MudShark technology is based on the multistage segmented solids separation approach developed and proven by the SharkGUT's success. This low-risk system actively separates, isolates, and traps solids that bypass downhole gas and solids separators. Numerous cup-type separators are run in series inside the tubing joints (28 cups per tubing joint insert). Numerous cups provide an effective method for firstly, "busting up" or dispersing the high-concentration solids slugs, and then secondly, separating out the solids for containment out of harm's way.

Figure 27 illustrates the MudShark's process sequence for busting up solids slugs, separation of solids and then capturing/containment of solids in the cups.

Figure 28 shows renderings of the MudShark components. Independently inserted and hung off in single tubing joints (using the API gap between tubing pins inside each tubing coupling), the inserts innovatively apply eccentrically oriented fiber-reinforced 3D printed thermoplastic cups, mounted on a 3/8" fiber-reinforced thermoplastic rod. Each cup was engineered for minimal pressure loss and sequentially staggerd in series for assurance of solids settling/containment into the cups. This solids separator is designed to work with a sucker rod pump's flow and no-flow cycle each pump stroke. During a sucker rod pump's downstroke, the pump's standing valve is closed with stoppage of flow in the tubing below the pump. In other words, it takes advantage of the cyclical rod pumping action for solids separation and containment.

Fiber-reinforced thermoplastics enable cost-effective manufacturing and complete corrosion resistance. Their ultra-high strength supports greater separation surface area and increased downhole solids containment capacity.

Multiple MudShark™ inserts can be run into each sequential Extended Intake Tubing system joint for increasing the downhole solids containment capacity.

Figure 29 shows an engineering drawing for MudShark inserts designed to be installed in a 2-7/8-inch tubing joint.

Figure 30 shows an optional reverse flow protection valve (for pump unseating risks) that can be installed above the gas separator as part of the BHA. Pump unseating presents a risk of excessive high-rate reverse flows that carry high-concentration solids. For example, unseating a pump at 8,000 feet depth with a low annular fluid level (4,000 psi pressure differential) can result in reverse flow of 31,000 barrels per day. Such a high-rate reverse flows risk solids-laden fluid bridging off around the MudShark cups and failing them. A sized port flow valve was engineered to limit the reverse flow through the BHA after a pump is unseated to approximately 1,000 bbls/day. Oilify's 3D metal printed boronized hydrodynamic HammerHead valves offer minimal pressure loss and high solids tolerance in the open flow direction, so porting this valve was a straightforward design change as a MudShark reverse flow protection valve. This effectively creates of a "leaky" check valve. During pumping the valve would be open with minimal pressure loss but would land on its seat for excessive flow reversal (after a pump is unseated). Forcing the flow through the valves ported smaller hole limits the u-tube rate.

A fully closing check valve alone would not be a good plan here since it would hold the tubing full of liquid and result in undesirable "wet" tripping wet. Therefore, this "leaky" check valve design would allow for the tubing to effectively drain during a workover, controlling the risk of damage to the MudShark's solids separation cups.

Field experience led to a second-generation design of a more robust and smaller outside diameter (OD) MudShark cup for the respective tubing size. Figure 31 shows a manufacturing picture of the MudShark inserts.

Operationally, Figure 32 shows how a MudShark simply inserts and hangs off inside a tubing joint (low risk, as is housed inside each tubing joint).

Figure 33 provides detailed MudShark insert specifications for the various tubing joint tubing sizes.

Flow loop testing with water confirmed operability and was useful for determining the optimal spacing distance between each cup for maximizing solids volume containment yet still being an efficient solids separator. Placing the cups too close together does not allow adequate space and time for settling solids into a cup (due to turbulence). Extensive use of artificial intelligence (AI) was used to iterate and determine optimal cup length and spacing between cups, as a function of sucker rod pump stroke rates and volumes. See Figure 34, showing pictures from a flow loop test where a high-concentration solids slug was busted-up-dispersed-diluted, then captured in the sequential multi-stage cups. It is estimated the solids containment capacity is approximately 50-60% of the internal volume of a tubing joint.

PUMP DESIGNED TO EFFICIENTLY CONVEY SOLIDS THROUGH ITSELF WITH LOW DAMAGE RISK

The expectation is that some solids will make their way through the BHA to the pump. The engineering intent is to avoid high-concentration solids slugs/slurries reaching the pump and filling it with solids and rendering it inoperable (i.e., stuck pump).

The pump therefore must be designed to still contend with solids. It should be designed to efficiently convey solids through itself with low risk of damage. Features such as vortex or torsional flow valves, minimization of pressure loss across the valves, hardened/toughened plunger/barrel/rod-guide materials, and plunger grooving. Vortex or torsional pump discharge assemblies have also proven beneficial.

BHA ABOVE THE ROD PUMP DESIGNED TO CONTROL SOLIDS FALLBACK RISKS

New Technology #3 – the SandShark^{TM} multi-stage solids slug busting separator for solids fallback protection or sucker rod pumps.

The expectation is that some solids will make their way through the lower BHA below the pump and through the pump, entering the tubing above the pump. These solids can accumulate above the pump and pose a risk of a stuck pump.

There are existing and operationally proven downhole pump solids fallback protection tools for artificial lift systems. They have been developed primarily for electrical submersible pumps (ESP's), for preventing damaging solids from falling back on top of the ESP during shut down. These approaches used for ESP's are not generally compatible or adaptable to sucker rod pumping.

Sucker rod pumping liquid rates and associated tubing liquid velocities are often too low for carrying the solids to surface. Therefore, a permanent "out of harm's way" downhole solids separation and containment solution would be required for a solids fallback prevention solution. Additional design challenges include the need for full tubing internal drift diameter to allow passage of the pump and rods. Further, there are reciprocating sucker rods inside the tubing above the pump all the way to surface.

A multistage slug busting solids separation and containment technology was hypothesized to be necessary for resolving solids accumulation in the tubing above a sucker rod pump. The tool and system embody the following design features:

- permanent separation and downhole containment of solids that have made it through the sucker rod pump,
- no impact to the rod string design or requirement for special/custom rod string components,
- absence of interference with the sucker rod string's reciprocal motion,
- does not require modifications to the sucker rod pump,
- does not restrict or limit the internal diameter of the tubing string,
- does not restrict or limit the annular flowby cross-sectional area to the casing,
- does not limit the tubing string's pressure or temperature ratings, and

- is cost effective.

Figure 35 and 36 detail a new patent-pending system-based tool that was developed, and was trade named the SandShark^{TM}. Figure 37 shows a BHA diagram example. Saponja[xxviii] provided extensive details for engineering and design.

CASE STUDIES

Field implementations and trials commenced effective May 2025. The challenge for developing new downhole solids separation technologies is that a lot of time and meaningful statistics (lots of well trials) are needed to prove performance, operability, low operational risks, and value. We are highly appreciative and grateful to the producers that are willing to partner for development of such technologies.

For SharkGUTs – Total installation count at the time of this paper's writing is approximately 20 wells. All but one have been deemed successful for increasing pump run life. One failure has been recorded, where the total amount of solids entering the BHA was excessive and plugged the entire BHA.

For MudSharks – Total installation count at the time of this paper's writing is approximately 25 wells. All but two are still running with several of them demonstrating increased pump run life. Two failures have been recorded due to pump unseating events damaging the uppermost MudShark insert's cups (flow to the pump was restricted thereafter forcing workovers to either replace the damaged MudShark or not re-run). Both wells had generation one cups and did not have the ported reverse flow protection valve installed.

Case Study 1 – Figure 38 shows a SharkGUT install in a solids-troublesome Canadian well. This high H_2S and corrosion risk well was experiencing solids-related pump failures every 2-3 months. Figure 39 shows sucker rod pumping parameters. The well is still operating without a workover after nearly 12 months.

Case Study 2 – SharkGUT installs on two solids-troublesome Canadian wells where both wells had high pump failure frequencies of every 2 months (4 SharkGUT inserts per well). Figure 40 shows a pump card on one of the wells recorded after several months of production, with an indication of no pump issues and no intake restriction. One of the wells lasted 8 months before a rod part/issue was recorded and the well was worked over. The SharkGUT inserts were successfully removed (see Figure 41 showing insert removal from the mud joints at surface). After insert removal, 2 meters (7 feet) of solids was found in the lowermost mud joint, indicating successful solids separation. The SharkGUT insert were immediately reinstalled and required no service on site.

Case Study 3 – MudShark (generation 1 cups) install on a solids-troublesome, stuck-pump well with high failure frequency. The well had been producing several weeks with six (6) MudShark inserts installed until the tubing anchor unset. The well was workover, but during the workover the MudShark cups were damaged when the pump was unseated. When the BHA was retrieved, the MudShark inserts were inspected and a number of the uppermost MudShark insert cups were found to be heavily damaged – see

Figure 42.The pumped-unseated excessive reverse flows had large amounts of scale debris which bridged around the uppermost MudShark cups (31,000 barrels per day reverse flow at 4,000 psi differential). New generation-two MudShark cups were then installed, and the well remains on production.

Case Study 4 – MudShark install (generation 1 cups). Cups retrieved at surface successfully captured solids, heavy paraffin and scale debris (see Figure 43)

CONCLUSION

For producing horizontal wells with a sucker rod pump, expect solids to arrive at the BHA as high-concentration slugs / slurries, that risk stuck or failed sucker rod pumps:

- overwhelming of single-stage solids separators
- rapid plugging of sand screens
- pumps packed full or partially full of solids below the plunger

It can be concluded that gas-liquid slug flows within a horizontal wellbore during sucker rod pumping are perpetual due to terrain-induced slugging (for most gas rates). Slugging transports solids (even at low liquid rates) and in the form of dunes/beds. These solids dunes/beds accumulate at the base of the curve, awaiting release as a high-concentration solids-slug from an excessive gas rate surge or spike. This is the process that fills a sucker rod pump with solids and sticks/fails it.

Increased production drawdown from improved gas separation BHA designs and from pumps placed deep in the wellbore curve has increased the risk of solids-related pump failures and stuck pumps.

Three new downhole solids separation technologies have been developed and are compatible with these BHA's. Solids separation technology breakthroughs have occurred with development of sequential multi-stage separation methods. Stepwise intentional busting up and dispersing high-concentration solids slugs before separation/containment of the solids out of harm's way is proving more effective than existing single-stage solids separators. This includes solids separation at all wellbore inclinations.

Field implementation has shown promise with reasonable early-time successes.

FIGURES

FIGURE 1 – PUMP FAILURE WITH BARREL, SOLIDS PACKED BELOW PLUNGER

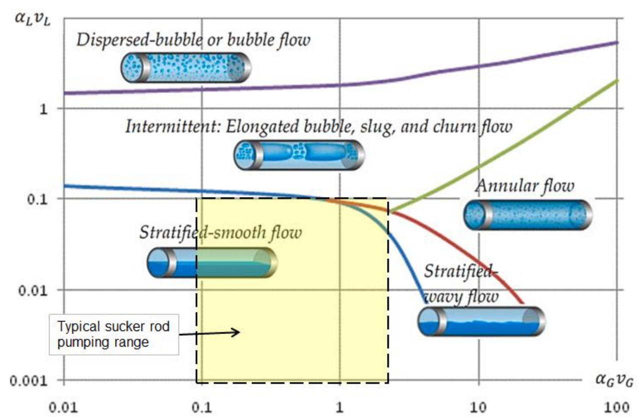


FIGURE 2 – SLUG FLOWS CAN OCCUR AT ALL GAS VELOCITIES IN A HORIZONTAL WELLBORE (STRAIGHT PIPE), BUT NOT AT ROD PUMPING RATES

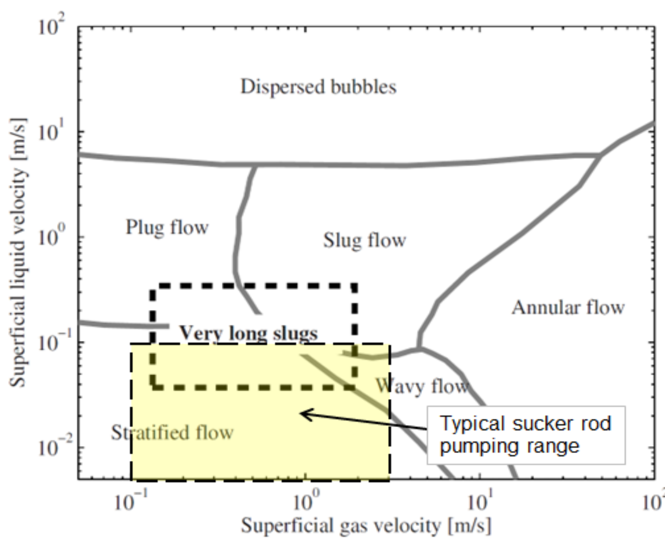


FIGURE 3 – VERY LONG SLUGS CAN FORM (STRAIGHT PIPE)

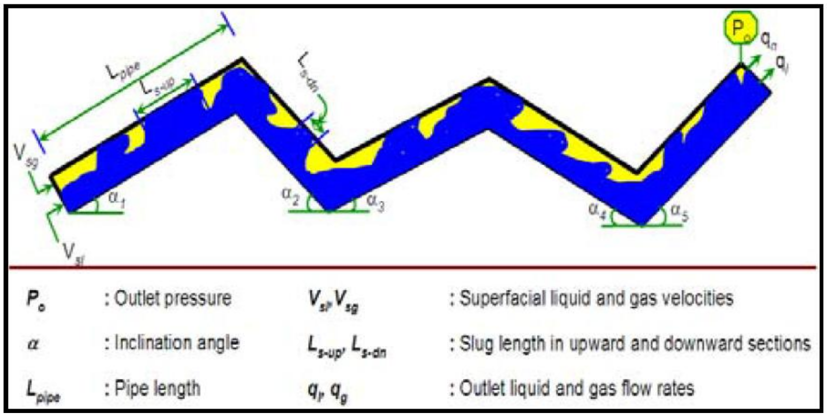


FIGURE 4 – SLUG FLOWS CAN OCCUR AT MOST GAS VELOCITIES IN AN HORIZONTAL WELLBORE DUE TO TERRAIN-INDUCED SLUGGING

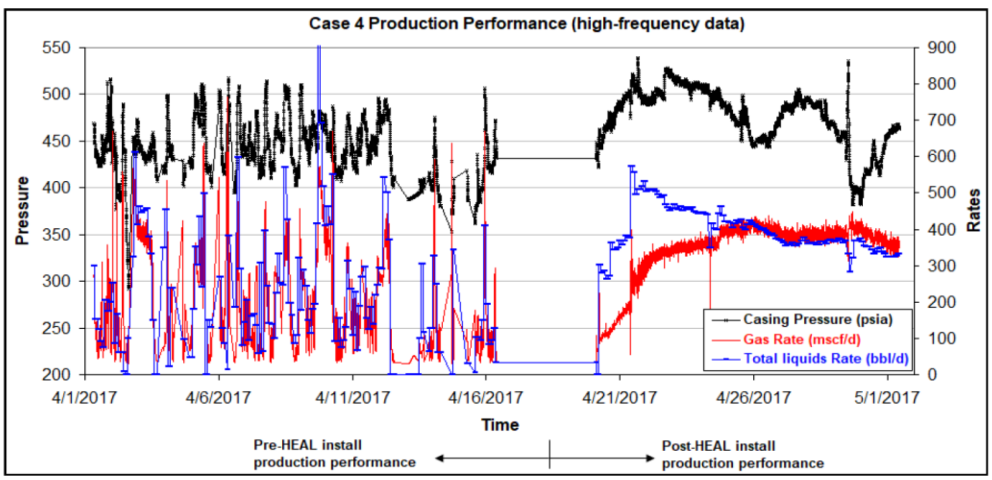


FIGURE 5 – SLUG CONTROL IN THE WELLBORE'S CURVE SECTION USING A VELOCITY TAILPIPE BHA

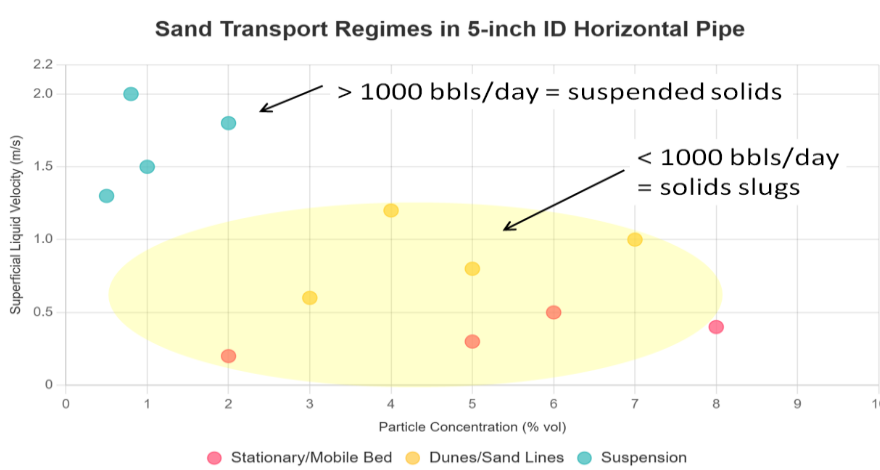


FIGURE 6 – SOLIDS TRANSPORT REGIMES VERSUS LIQUID VELOCITY

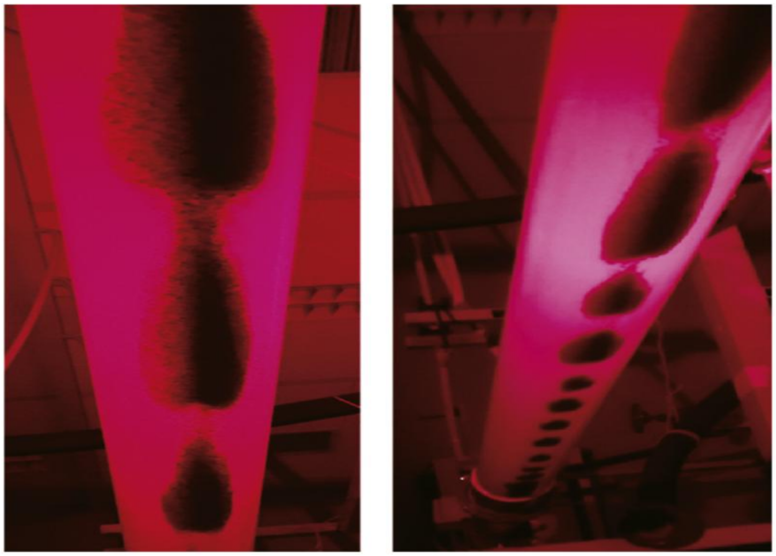


FIGURE 7 – SOLIDS TRANSPORT (SALTATION) ALONG A HORIZONTAL WELLBORE IN THE FORM OF DUNES / BEDS

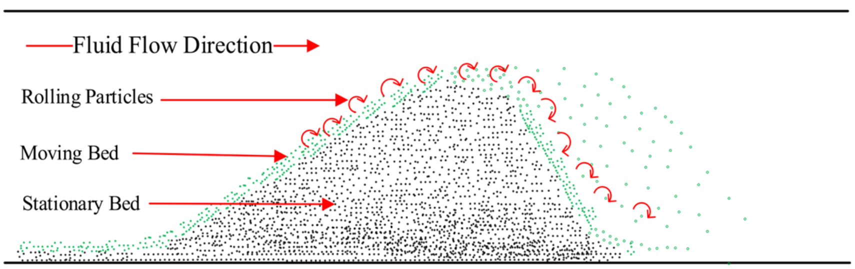


FIGURE 8 – SOLIDS TRANSPORT AS MIGRATING DUNES / BEDS

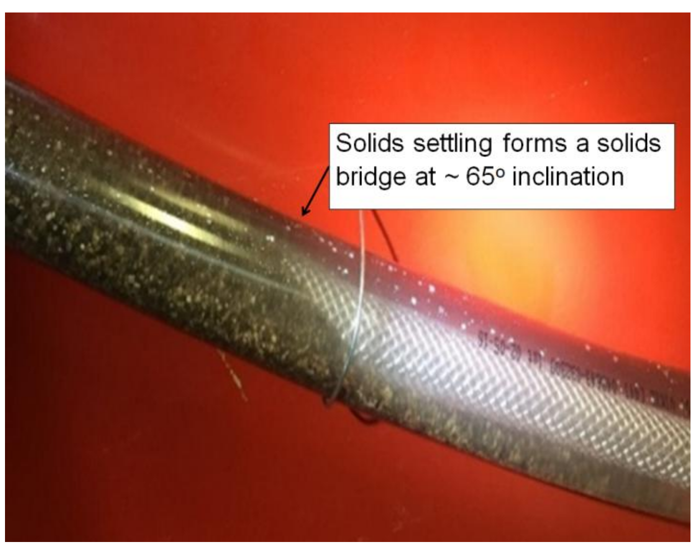


FIGURE 9 – SOLIDS SETTLING ANGLE OF REPOSE IS 65 DEGREES FOR TYPICAL SOLIDS PARTICLE SIZES EXPERIENCED FOR ROD PUMPING

FIGURE 10 – SOLIDS DUNE/BED MIGRATION ACCUMULATION NEAR THE BASE OF THE WELLBORE'S CURVE SECTION

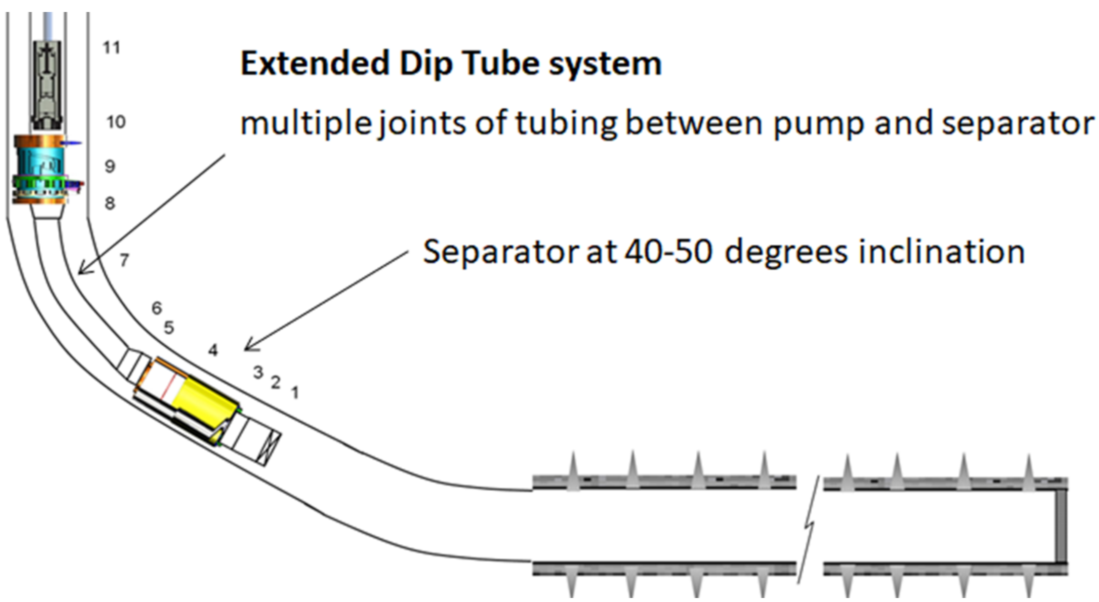
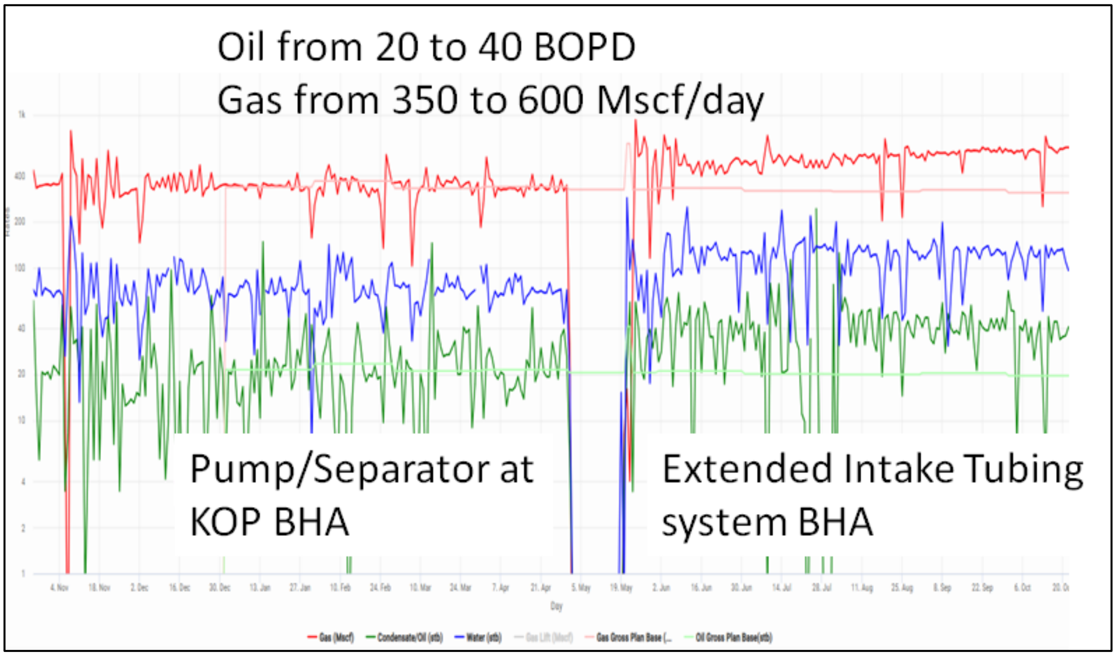


FIGURE 11 – EXTENDED INTAKE TUBING OR DIP TUBE SYSTEM BHA CONFIGURATION



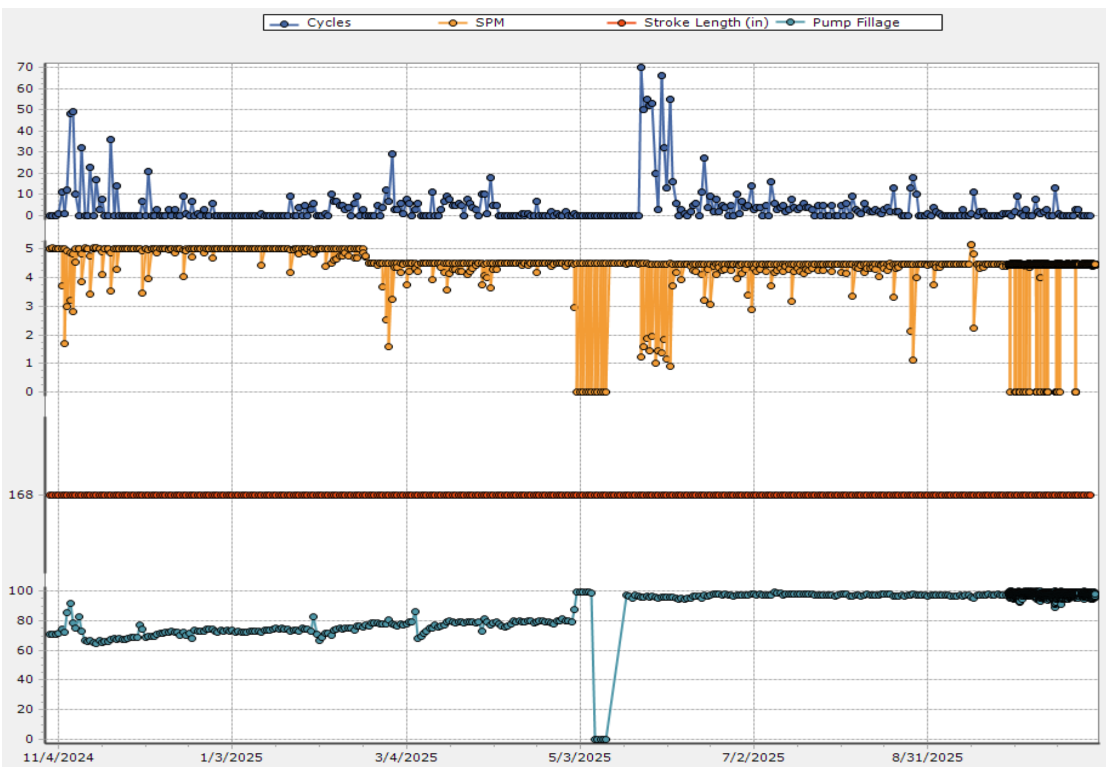


FIGURE 12 – EXTENDED INTAKE TUBING SYSTEM RESULT: MORE PRODUCTION AND STABLE CONDITIONS

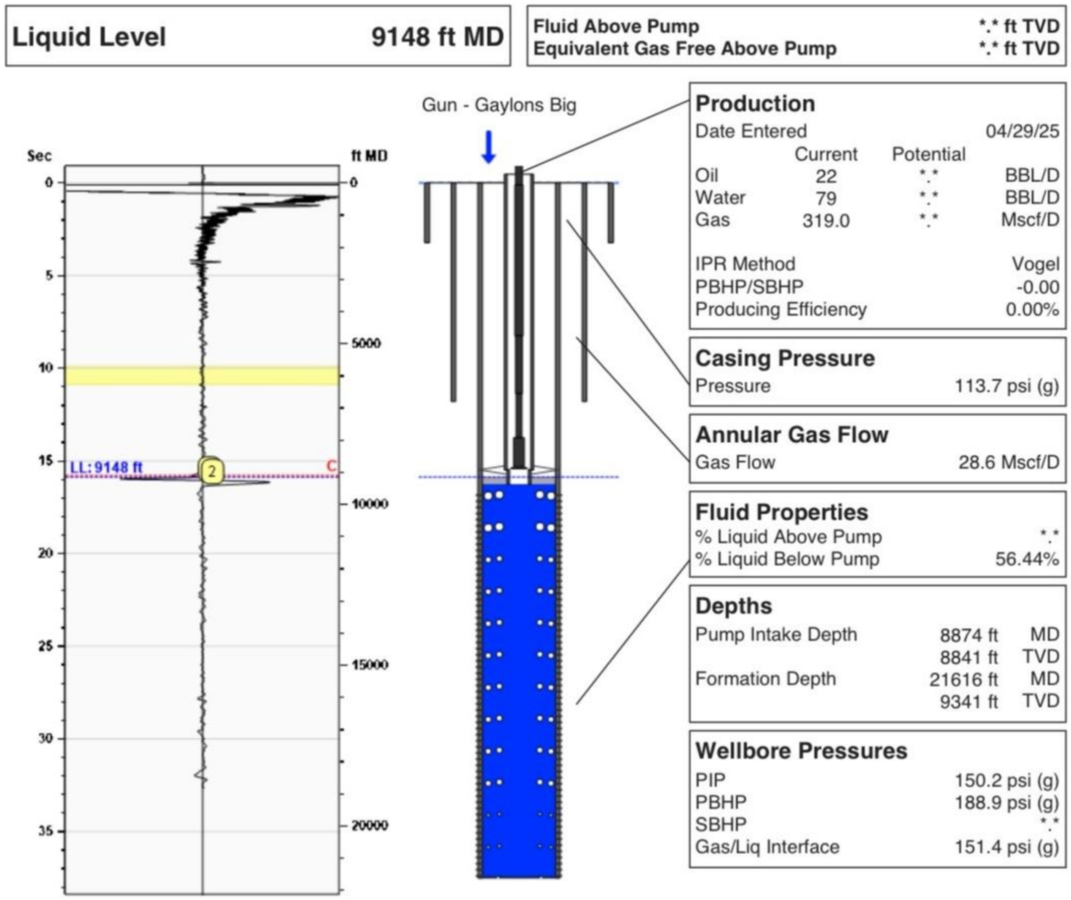


FIGURE 13 – EXTEND INTAKE TUBING SYSTEM FLUID LEVEL RECORDED AT THE SEPARATOR'S DEPTH, BELOW THE PUMP

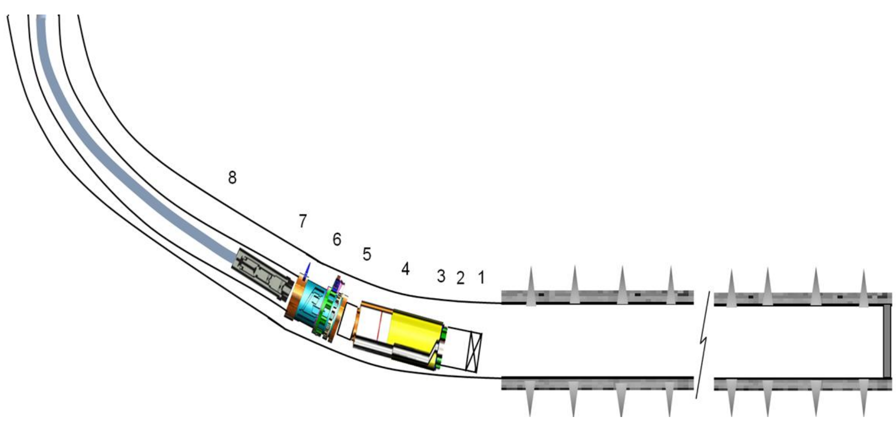


FIGURE 14 – HIGH INCLINATION SUCKER ROD PUMPING IN THE CURVE BHA CONFIGURATION

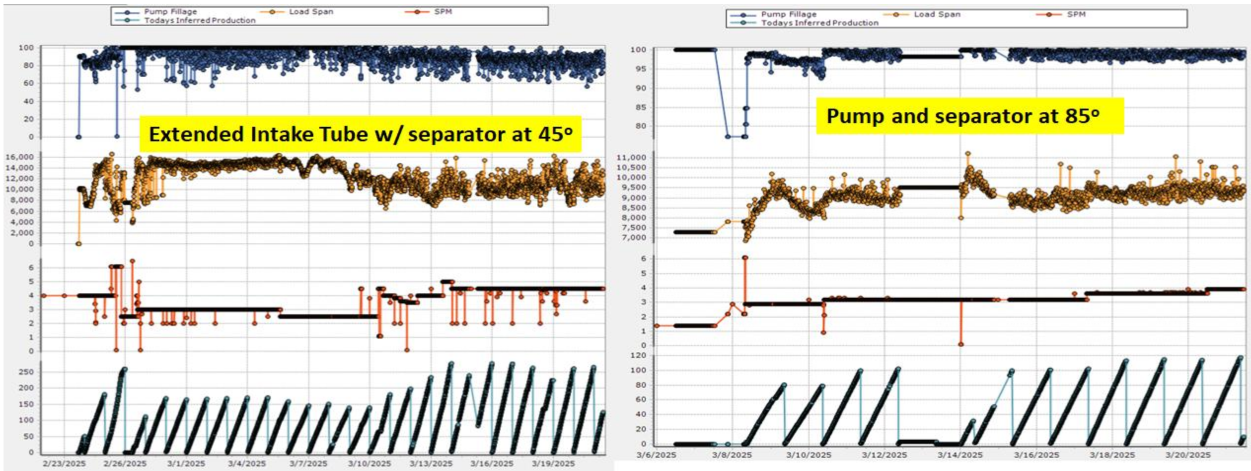


FIGURE 15 – COMPARISON OF BHA'S CONFIGURATIONS IN THE CURVE

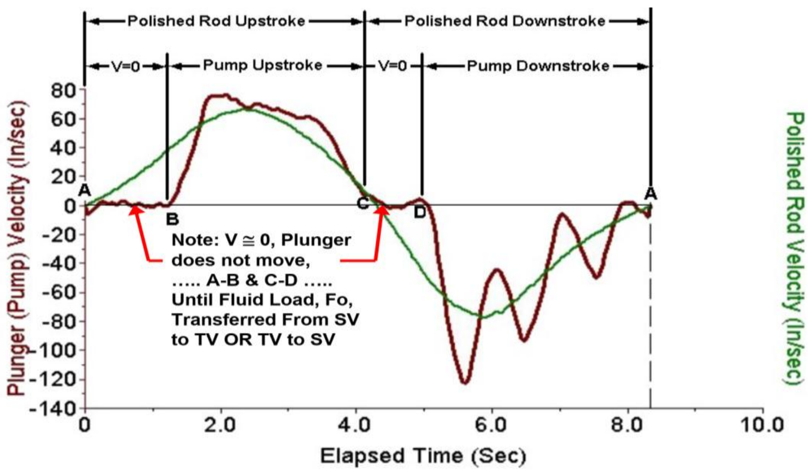


FIGURE 16 – HIGHLY VARIABLE LIQUID INFLOW RATE INTO A PUMP DUE TO UPSTROKE PLUNGER VELOCITY SLINGSHOT AFFECT

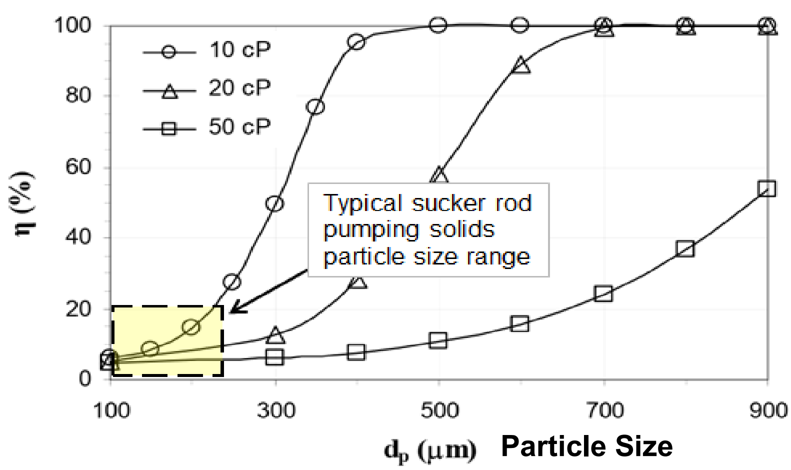
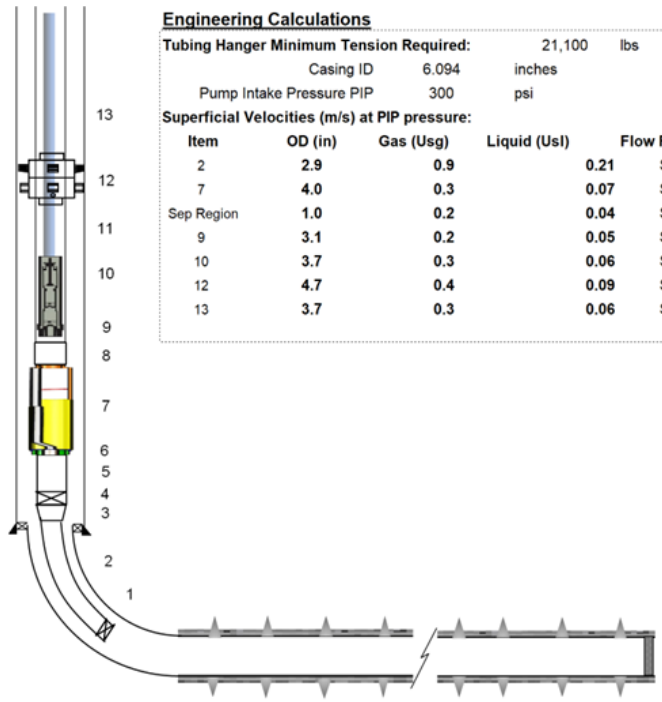


FIGURE 17 – DOWNHOLE CYCLONIC-GRAVITY SOLIDS SEPARATOR EFFICIENCY AS A FUNCTION OF PARTICLE SIZE; LOW FOR ROD PUMPING



Engineering Calculations

Tubing Hanger Minimum Tension Required:		21,100	lbs	
Casing ID	6.094	inches		3.9
Pump Intake Pressure PIP	300	psi		liner

Superficial Velocities (m/s) at PIP pressure:

Item	OD (in)	Gas (Usg)	Liquid (Usl)	Flow Regime
2	**2.9**	**0.9**	**0.21**	Slug
7	**4.0**	**0.3**	**0.07**	Slug
Sep Region	**1.0**	**0.2**	**0.04**	Slug
9	**3.1**	**0.2**	**0.05**	Slug
10	**3.7**	**0.3**	**0.06**	Slug
12	**4.7**	**0.4**	**0.09**	Slug
13	**3.7**	**0.3**	**0.06**	Slug

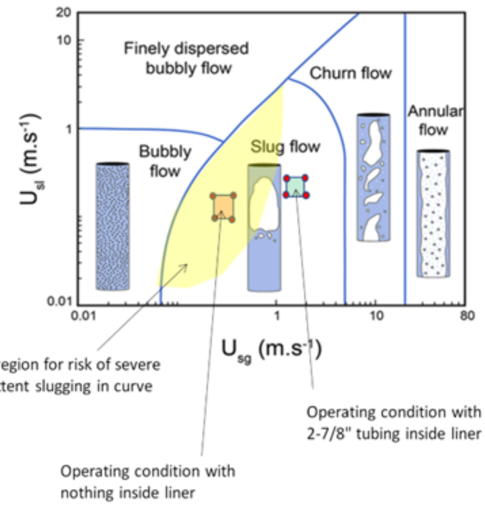


FIGURE 18 – AVOIDING THE SLUG FLOW REGIME'S REGION OF SEVERE INTERMITTENT SLUGGING USING AN ENGINEERED BHA CONFIGURATION

Tubing String Details (Number from bottom up)

No	Item Description	Length (m)	Depth mKB	Remarks
1	88.9mm EUE bull plug	0.30	1487.1	80° inclination
2	88.9mm EUE tubing mud joints (x 3)	28.95	1486.8	extended for slug control
2a	**SharkGUT™** high angle solids separation inserts (6.1m each x 4 inserts)		1457.9	goes inside mud joints
3	139.7mm OD **55 series WhaleShark™** packerless separator (SCR adapter kit required)	6.20	1457.9	139.7mm (5.5") OD
4	88.9mm J-55 EUE handling pup joint	1.20	1451.7	
5	88.9mm EUE tubing joints (x 20), **Extended Dip Tube** system	193.00	1450.5	for top hold down pump
6	88.9mm EUE PSN	0.35	1257.5	52.5° inclination
7	88.9mm EUE tubing joints (x 2)	19.30	1257.1	
8	177.8mm x 88.9mm EUE Tubing Anchor Catcher (slimhole equivalent)	1.62	1237.8	high annular flowby
9	88.9mm EUE Injection Port sub /w 2x3500kPa checks	1.24	1236.2	
10	88.9mm EUE tubing to surface		1234.9	

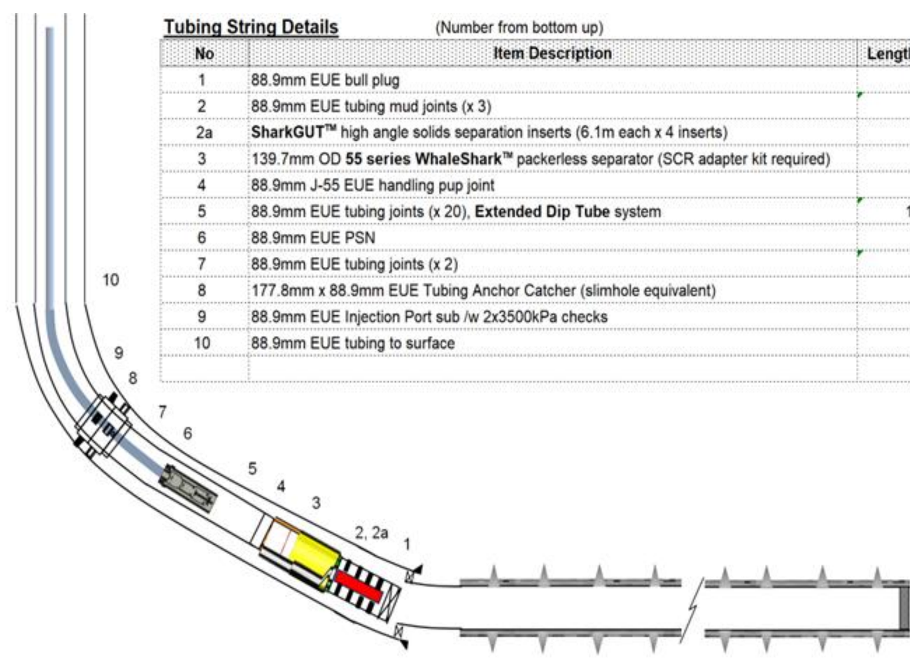


FIGURE 19 – SHARKGUT HORIZONTAL SOLIDS SEPARATOR EXAMPLE BHA

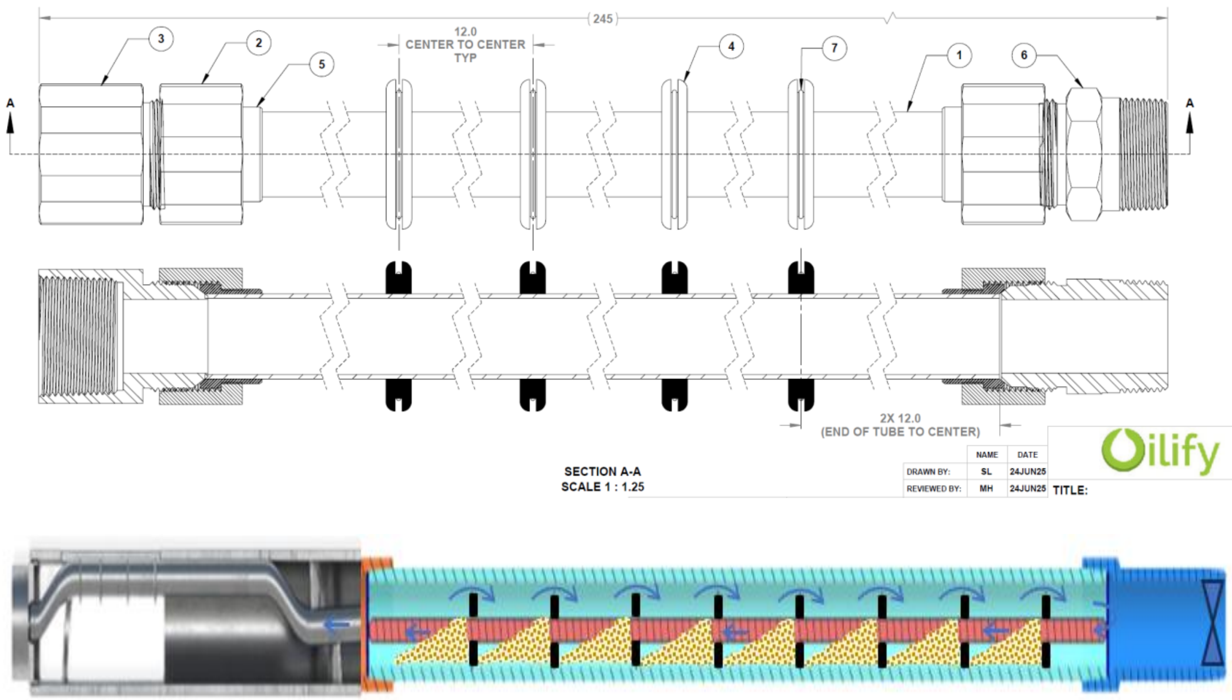


FIGURE 20 – SHARKGUT MUD JOINT INSERT ENGINEERING DRAWING AND RENDERING SHOWING MULTI-STAGE WEIRS CAPTURING OF SOLIDS

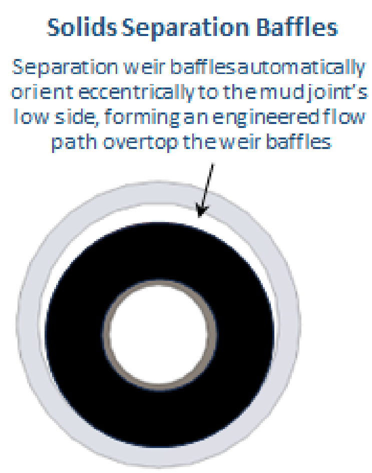


FIGURE 21 – SHARKGUT WEIRS AUTOMATICALLY GRAVITY ORIENT TO THE LOW SIDE OF THE HOLE

FIGURE 22 – SHARKGUT MANUFACTURING SHOWING 19 WEIRS PER 20-FOOT-LONG MUD JOINT INSERT

Horizontal Mud Joint Solids Separator Insert Specifications			
Series Model Name	20	25	30
Weir Outside Diameter, in [mm]	1.8 [45.7]	2.2 [57.2]	2.8 [71.1]
Tube Outside Diameter, in [mm]	1.0 [25.4]	1.25 [31.8]	1.25 [31.8]
Tube Inside Diameter, in [mm]	0.8 [20.3]	1.12 [28.4]	1.12 [28.4]
Length, feet [m]	20.0 [6.1]	20.0 [6.1]	20.0 [6.1]
Connections (box / pin)	1.0" NPT	1.25" NPT	1.25" NPT
Tensile Rating, $klbs_f$ [kdaN]	0.5 [0.2]	0.5 [0.2]	0.5 [0.2]
Burst/Collapse Pressure, psi [kPa]	250 [1,723]	250 [1,723]	250 [1,723]
Maximum Capacities			
liquid bbl/day [m^3/day]	300 [48]	500 [80]	500 [80]
Insert Materials	304 stainless steel tube / end fittings Viton rubber weirs (400^{o}F or 205^{o}C rating)		

FIGURE 23 – SHARKGUT HORIZONTAL SLUG BUSTING SOLIDS SEPARATOR SPECIFICATIONS

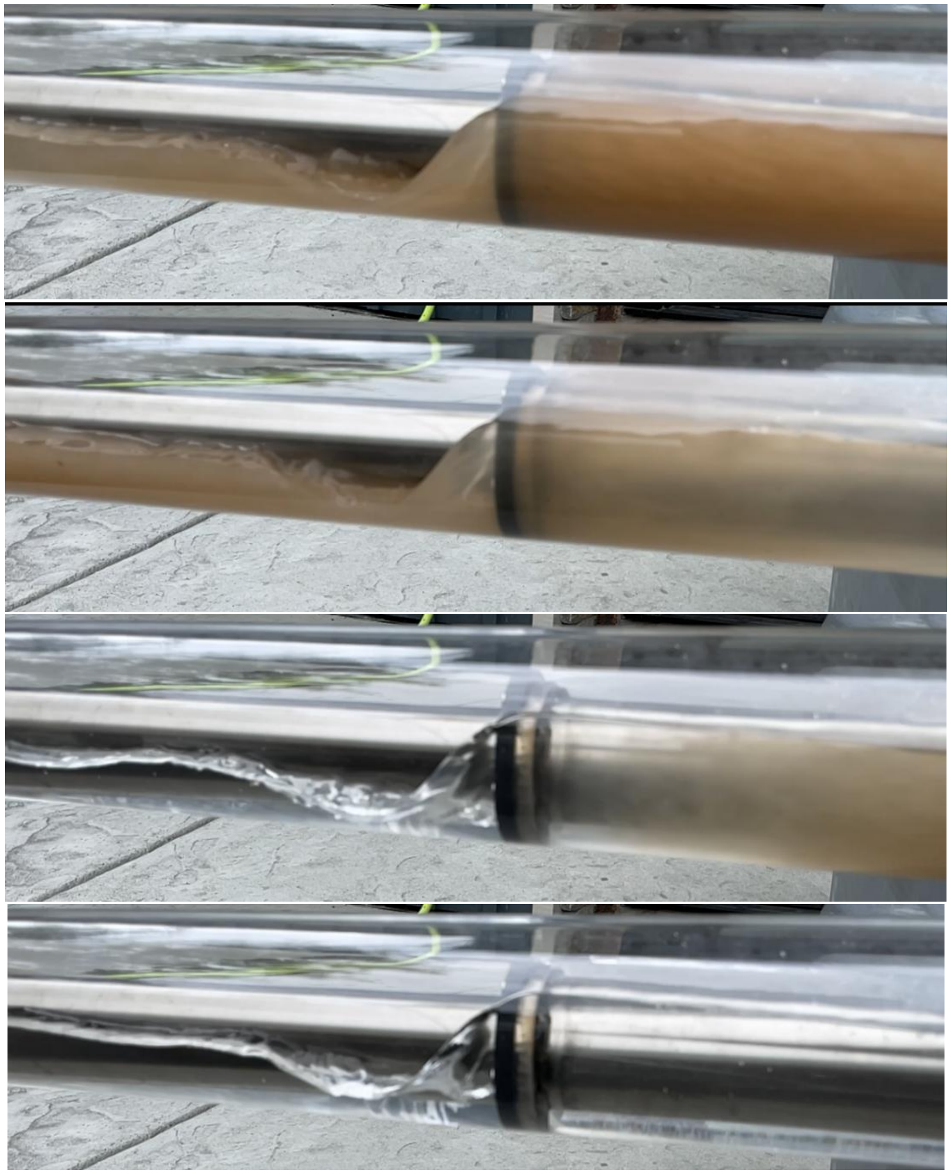


FIGURE 24 – SHARKGUT FLOW LOOP TESTING "BUSTING UP" AND DISPERSING A HIGH-CONCENTRATION SOLIDS SLUG

FIGURE 25 – SOLIDS SEPARATED AND CONTAINED BEHIND A WEIR

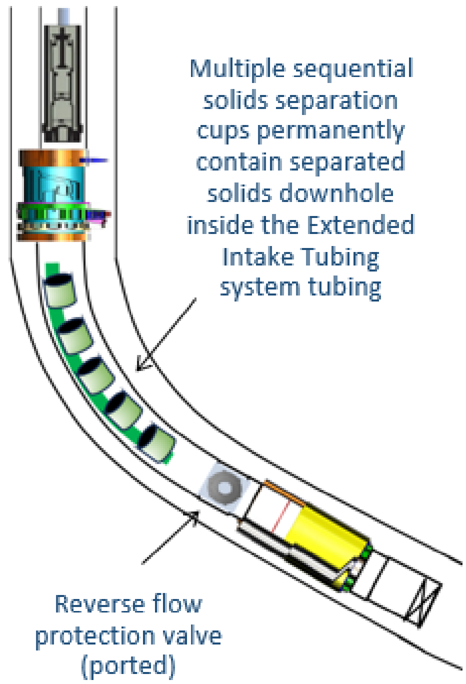


FIGURE 26 – MUDSHARK SLUG BUSTING SOLIDS SEPARATOR FOR EXTENDED INTAKE TUBING SYSTEM BHA'S

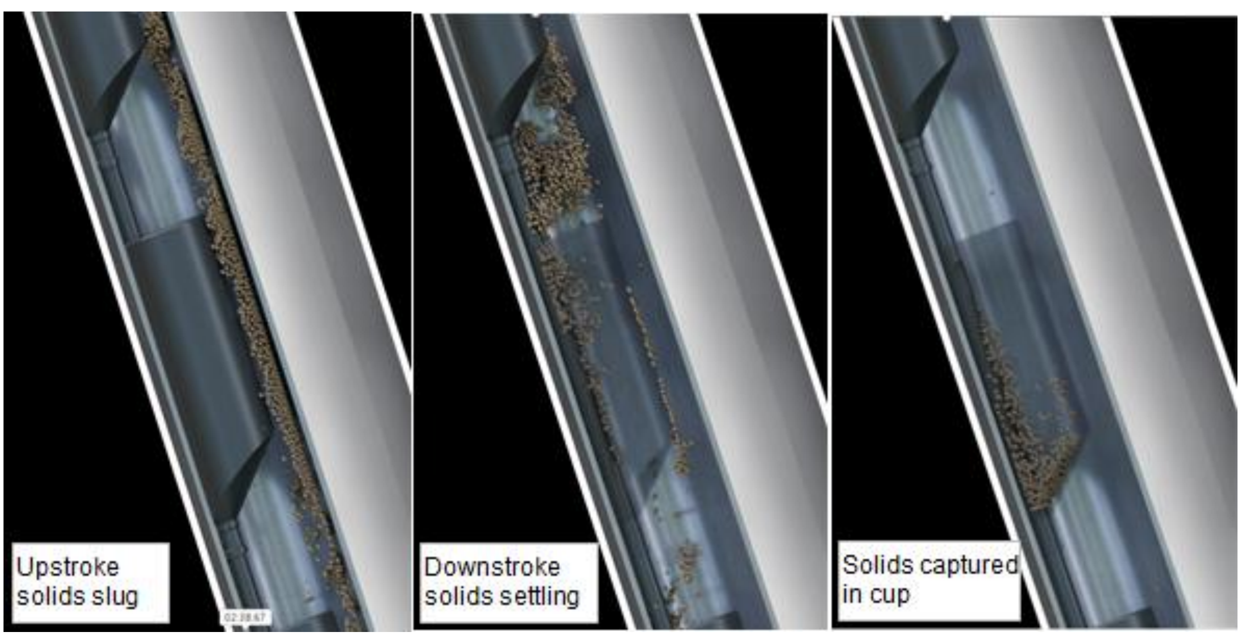


FIGURE 27 – MUDSHARK SOLIDS SEPARATION AND CONTAINMENT PROCESS SEQUENCE

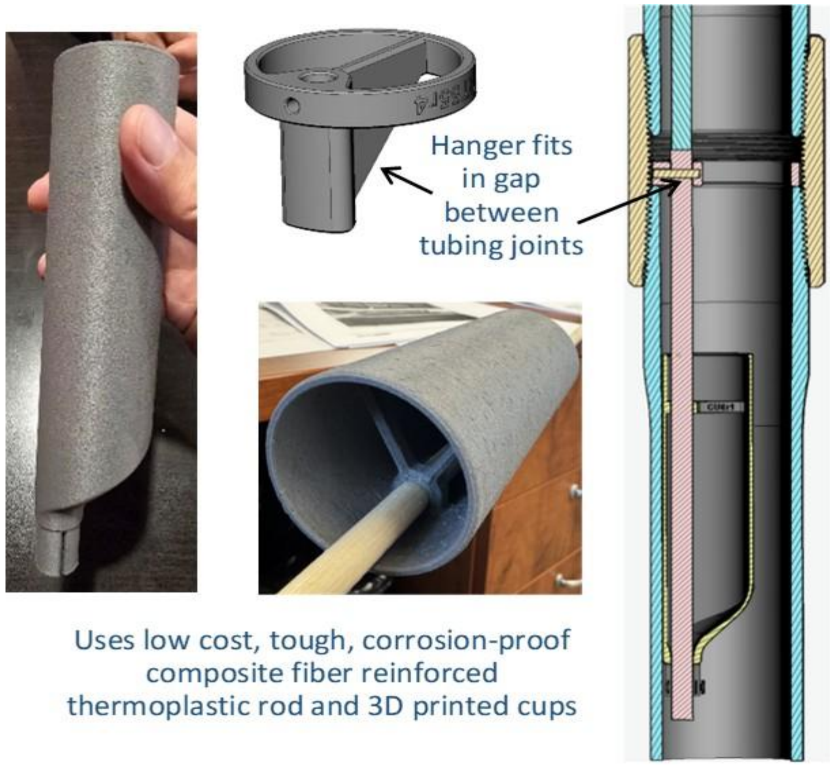


FIGURE 28 – MUDSHARK INSERT COMPOSITE COMPONENTS

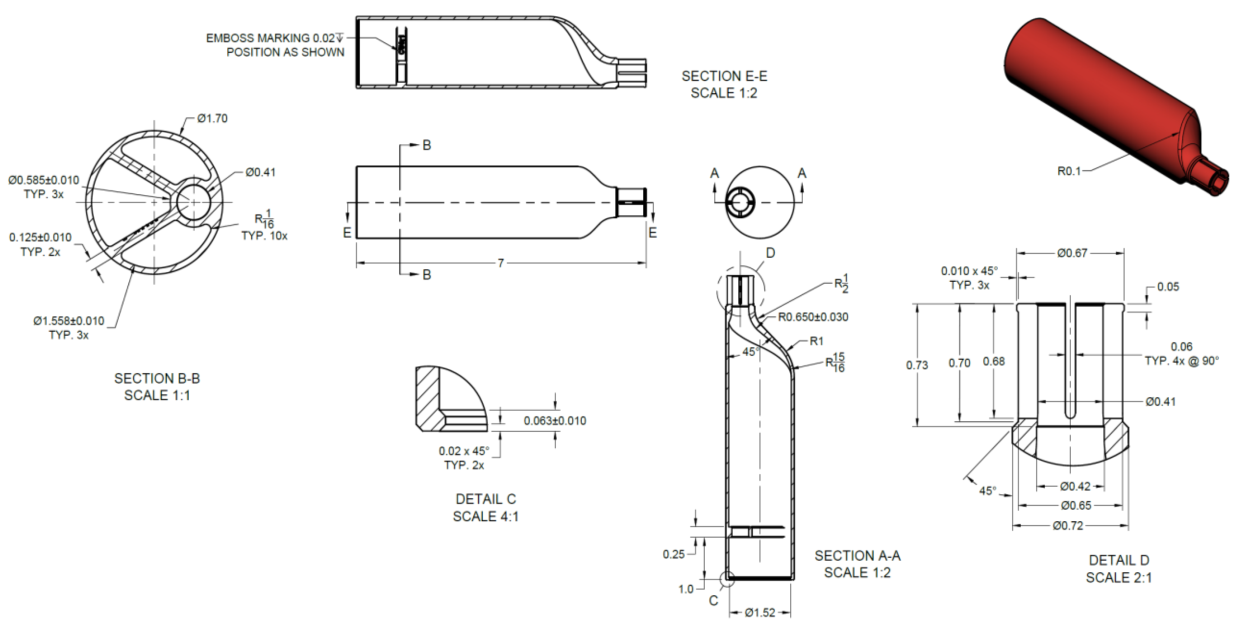


FIGURE 29 – MUDSHARK ENGINEERING DRAWING FOR 2-7/8 EUE TUBING

FIGURE 30 – 3D METAL PRINTED PORTED HAMMERHEAD REVERSE FLOW PROTECTION VALVE FOR CONTROLLING PUMP UNSEATING RISKS

FIGURE 31 – MUDSHARK MANUFACTURING

FIGURE 32 – LOW OPERATIONAL RISK, AS INSERTS INTO (HOUSED INSIDE) STANDARD TUBING JOINTS

MudShark™ Insert Specifications			
Series Model Name	20	25	30
For Tubing Size, in [mm]	2-3/8 [60.3]	2-7/8 [73.0]	3-1/2 [88.9]
Cup Outside Diameter, in [mm]	1.2 [30.5]	1.7 [43.2]	2.25 [57.2]
Length, feet [m]	29.5 [9.0]	29.5 [9.0]	29.5 [9.0]
Temperature Rating, °F [°C]	280 [138]	280 [138]	280 [138]
Tensile Rating, lbsf [daN]	10,000 [4,450]	10,000 [4,450]	10,000 [4,450]
Solids Capacity/Insert, bbls [m^3]	0.06 [0.01]	0.10 [0.014]	0.13 [0.02]
Materials: Rod – polyketone carbon fiber reinforced thermoplastic Cup/Hanger – PA6 glass fiber reinforced thermoplastic, cinch clamp 316ss			

FIGURE 33 – MUDSHARK INSERT SPECIFICATIONS

FIGURE 34 – MUDSHARK FLOW LOOP TESTING WITH SUCCESSFUL BUSTING UP OF A HIGH-CONCENTRATION SOLIDS SLUG AND CAPTURING OF THE SOLIDS INSIDE THE CUPS

FIGURE 35 – SANDSHARK TOOL’S SOLIDS SEPARATION ASYMMETRIC MULTI-STAGE WEIRS AND CHANNELS THREE-DIMENSIONAL RENDERING

FIGURE 36 – SANDSHARK’S UNIQUE PUMP SOLIDS FALLBACK PROTECTION SOLUTION WITH SEPARATION AND CONTAINMENT ABOVE THE PUMP

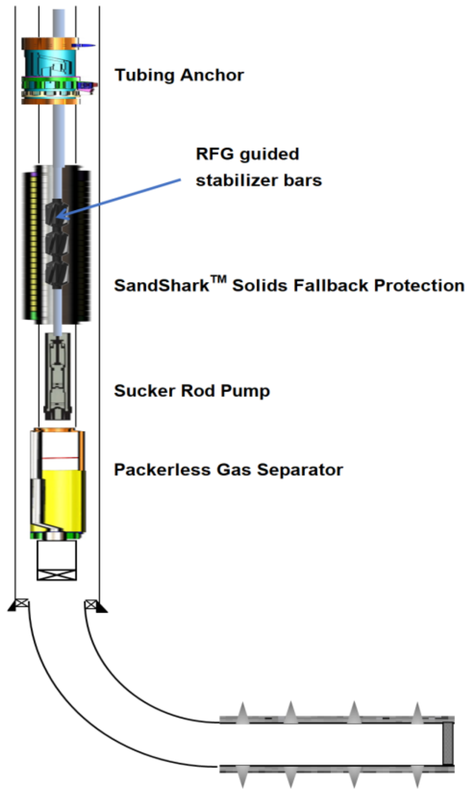


FIGURE 37 – SOLIDS FALLBACK PROTECTION BHA ABOVE THE PUMP

FIGURE 38 – SHARKGUT INSTALL CASE STUDY

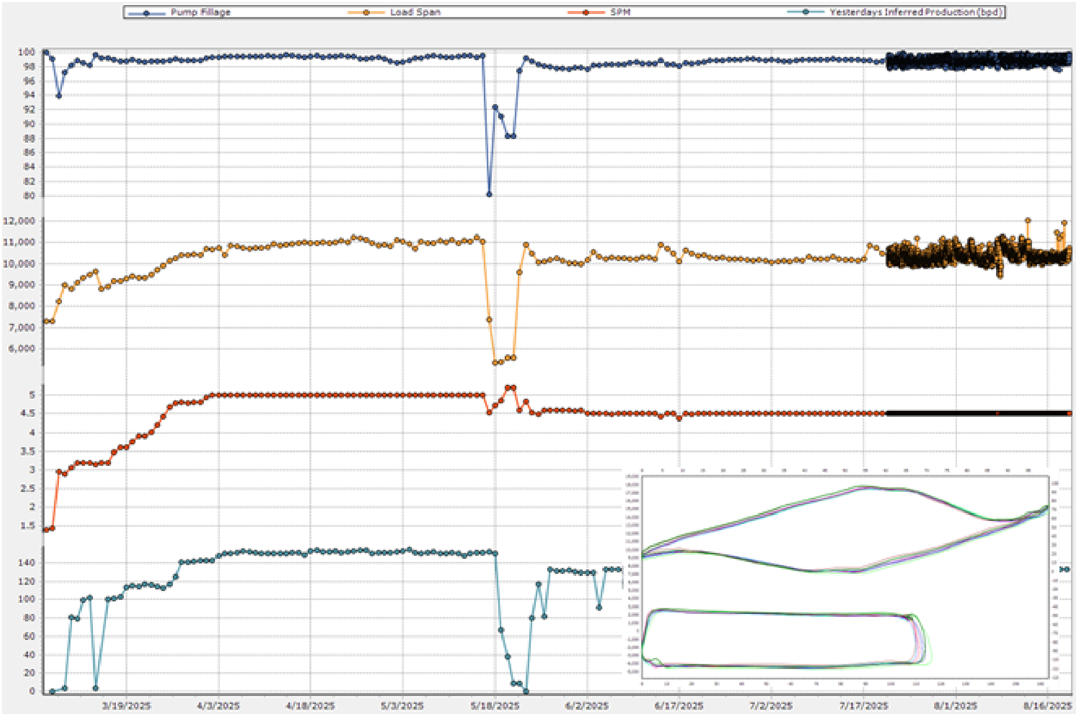


FIGURE 39 – SHARKGUT CASE STUDY, IMPROVING FAILURE FREQUENCY BY A FACTOR OF 4 TIMES (AND STILL RUNNING)

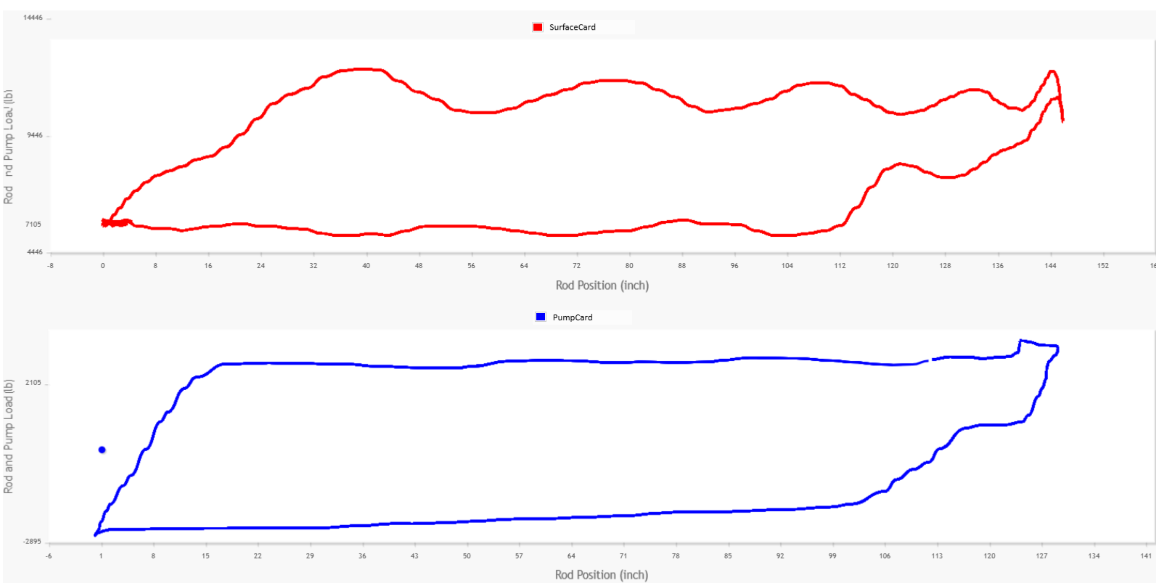


FIGURE 40 – SHARKGUT CASE STUDY, PUMP CARDS AFTER SEVERAL MONTHS SHOWING NO INDICATION OF PUMP ISSUES OR AN INFLOW RESTRICTION

FIGURE 41 – SUCCESSFUL SHARKGUT INSERT RETRIEVAL AFTER 12 MONTHS OF PRODUCTION (PARTED RODS WORKOVER) AND RE-RUN

FIGURE 42 – MUDSHARK FAILURE DUE TO PUMP UNSEATING CASE STUDY

FIGURE 43 – SOLIDS SEPARATED AND COLLECTED/CONTAINED INSIDE A MUDSHARK CUP

ENDNOTES

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