ENHANCED OPTIMIZATION OF DEVIATED WELLS UTILIZING GREENSHOT: A PERMANENT, AUTOMATED FLUID LEVEL SYSTEM

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ABSTRACT
Longer laterals, better perforations and larger frac jobs have all enabled increased production capabilities, yet production optimization practices have remained stagnant and, in doing so, limit the ability to draw wells down more aggressively. The data provided in the most common fluid level processes does not meet the challenges generated by fluctuating well dynamics and conditions. The irregularity and inconsistency of current fluid level measurement systems and downhole cards provide an incomplete snapshot of the well conditions when a more complete solution is needed for optimization. With a permanent, automated fluid level system, reservoir and fluid data is continuously attained.

By utilizing a permanent, automated fluid level system located at the well head, the frequency of casing pressure buildups, acoustic velocity shots and fluid level shot data can be drastically increased. Doing so allows for more accuracy in data for pump intake pressure, produced gas up casing, fluid gradient and gas-free fluid levels on rod pumped wells.

The system is designed to function without high-pressure nitrogen or C02 and utilizes the wells' naturally produced casing gas, making it a truly 'green' technology.

Paired with properly tuned algorithms and current optimization practices, these data points give a clearer and more complete story of what rod pumped wells experience continuously throughout the day. Additionally, more information about the reservoir is produced than previously available. The data is collected, stored and accessed using a cloud-based interface, which means access can be provided instantaneously and from anywhere in the world without the use of dh gauges.

A growing number of wells being produced on sucker rod pump are offering high PIP and high fluid levels above pump, yet production is being limited due to gas interference caused by reservoir dynamics. Pumping through these ever-changing scenarios more aggressively is often the solution, yet this change in optimization practices cannot take place without ensuring the system is not overloaded and rod buckling is not taking place. To have this conversation, accurate PIP and Fluid levels must be understood on a frequent basis.

This paper aims to introduce the GreenShot, how it works, and what it provides to the operator as well as present case study results that show the production improvements supplied utilizing GreenShot while depicting robustness and accuracy.

INTRODUCTION
For years, the accuracy of pump intake pressure (PIP) determined from fluid level has been questioned, particularly in deep wells with high, gassy fluid levels. After 66 years of trying, the industry still struggles to find an accurate method for computing pump intake pressure in gassy wells with high fluid levels. Present methods work when there is no gas and give reasonable answers in pumped off wells, neither of which are scenarios in today's optimization challenges. The errors are slight enough to use the predictions to safely operate the well. However, these methods are insufficient to fully harness optimization capabilities on a well-by-well basis.

An unoptimized well means production left behind and missed opportunity and revenue. As these inaccuracies grow larger due to longer laterals, larger fracs, more zones, more undulations and more frac communication between wells, the need for accurate casing gas rates, fluid gradient and pump intake pressure (PIP) data is more important than ever before.

Unconventional reservoirs offer a behavior quite different than conventional reservoirs, see [2, 7] due to desorption of gas, multiphase flow, non-Darcy flow and non-static permeability. With step decline rates, this makes optimization a priority when producing these wells, cf. [5, 9].

In answer to the industry's needs, GreenShot is a permanently installed fluid level, PIP and casing gas calculating device. This technology, developed by Dr. Sam Gibbs and Ken Nolen, cf. [6], provides a complete picture of a well's pumping condition and opportunities for production optimization. Averaging multiple pressure buildups taken in each day has proven useful in computing PIP, as implemented in the permanently installed GreenShot.

Not only does GreenShot remove the need for standalone fluid levels measurement by offering automatically scheduled as well as on demand fluid level shots, but GreenShot removes the mystery behind rod pumping. Traditional pump off controllers only offer part of the picture by taking a snapshot of the well at a particular time. Trending downhole data and analyzing pump fillage helps the operator understand how full the pump is but not how the reservoir is reacting to pumping. GreenShot offers an additional depth to the analysis by providing measured fluid level, giving insight into how much production the well is capable of.

Measurements have shown that fluid level and PIP change slowly. Measured pressure buildups or casing gas rates change rapidly, which is why averaging multiple buildups is much more effective. Gathering multiple buildups is labor intensive for a human and not a realistic expectation for the large scale well count. It is only achievable with a permanently installed programmable device.

As mentioned above, the current industry standard methods are inaccurate in estimating PIP, fluid gradient and casing gas rates. This condition stems from their assumption that there exists a gas column above the fluid column, which when incorporated in the calculation lightens the overall fluid gradient. This leads to questionable PIPs in deep gassy wells with high fluid levels. The erratic behavior of gas production is depicted in Figure 4, showing an old Barton chart. Erratic gas rates and fluid production are problematic in unconventional wells, cf. [4].

There is a growing number of rod pumped and ESP wells experiencing high fluid levels and gas interference issues, which are limiting effective drawdowns and desired production. Often, the casing gas rates and total gas production are overestimated on these wells due to a lack of methods available, preventing operators from making the appropriate decision on how to optimize these wells. This practice erroneously attributes artificially light fluid gradient, PIP and gas free fluid level values to the well, hiding potential production opportunities. Due to the low PIP and the assumption that the well is carrying thousands of feet of foamy fluid level, the operator is blind to the potential of more production on the well.

Using GreenShot, the operator gets the true picture of what is happening downhole and is able to take action accordingly. Figure 4 shows a GreenShot Installation. For instance, a well's original design programs are routinely used to estimate the current loading conditions of a well using fluid gradient, PIP and gas rates at pumped off condition, which represents a well's worst-case scenario. This ensures that the overall system cannot be overloaded by the worst or current conditions. This also means that the design could be optimized if the current fluid level is known. Part of the methodology for GreenShot is to rerun designs and identify production opportunities to maximize revenue for the operator.

GreenShot is a versatile technology as it can be applied to different artificial lift methods such as ESPs and rod lift. Also, since GreenShot does not utilize foreign material to create the shot but instead uses the wells own energy, it is environmentally friendly and helps decrease carbon footprint of an installation.

Finally, GreenShot is able to identify downhole conditions and allow the operator to make conscious decisions to maximize profit. For instance, GreenShot can recognize slug flow, gas interference and flumping, all of which are usually problematic for the operator. Traditional pump controllers shut down during these conditions erroneously, assuming them to be a pumped off condition. The unit is shut down to avoid damage when actually there is ample production to capture, and large buoyancy effects, which reduces equipment loading and improves rod buckling avoidance. Having advanced knowledge of these conditions enables operators to maintain pumping operation and pump through these conditions sagely without losing production and damaging equipment.

If draw down and increased production is the goal, single gas rates taken once/quarter, at best, are not adequate for increased production and improved optimization. A permanently installed system calculating accurate gas rates, gradients and PIP's is needed. With GreenShot's enhanced measurements and calculation techniques, accurate values for PIP and gas rates are used in conjunction with design programs to identify potential production increase opportunities where these wells can be produced through gassy conditions, allowing for drawdown and production increases while preventing excessive damage to the system, all of which has been previously thought of as unachievable.

WHAT IS GREENSHOT?

Components and Functionalities:

The GreenShot is a two-piece system consisting of a controller and shooting manifold. Together, these two pieces form a permanent, automated fluid level system that brings fluid level frequency, accuracy and consistency to ESP and rod pump applications.

The GreenShot shoots automatic fluid levels daily using the well's produced casing gas in a closed system. The method is acoustic, meaning the system is creating a pressure wave or sound wave and measuring this wave as it surrounds tubing, working its way down casing at the speed of roughly 1200 feet per second (acoustic velocity) and back to surface.

Another advantage of GreenShot is that it utilizes "green" energy, meaning that nothing foreign is injected into the well to create the acoustic wave or emitted from the well that would pollute the atmosphere. The system functions without high-pressure nitrogen or CO_2. This is a key feature that allows oil and gas producers to limit the amount of greenhouse gases released to the atmosphere during oil and gas production and recovery. GreenShot can shoot up to 48 fluid levels per day, one acoustic velocity shot per week and 288 pressure buildups per day utilizing the wells produced casing gas.

The GreenShot shoots fluid levels via the closure of a shooting valve that separates the flowline and casing line. As the pressure differential across this valve is built, a shot size i.e., delta is created; the larger the delta, the larger the "shot." Once the desired delta is achieved, the shooting valve is cycled rapidly. The energy that is created is then amplified through the surge tank, creating the shot. The acoustic transducer and GreenShot sensor assemblies are used in unison to monitor the round trip of this shot from the fluid level back to the well surface. The common shot delta utilized on a typical GreenShot application tends to be anywhere between 1-10 psi.

The time needed to complete the round trip of the shot is monitored and recorded. Once the round trip is complete and all data recorded, the shooting valve returns to its normally open state and free flow of the well resumes.

This process is repeated throughout the day at various durations and with various pressure deltas to achieve fluid level shots, acoustic velocity shots and pressure buildups. Figure 1 shows the basic flow through the shooting manifold.

Pressure buildups are acquired by closing the shooting valve once every five or 10 minutes depending on the desired number of gas rates. The shooting valve remains closed for a period of 7.5 seconds while casing pressure rise is monitored over this period via the GreenShot Sensor. After 7.5 seconds have passed, the shooting valve opens, and normal flow is resumed while the casing gas rate is captured in the interface and history for later viewing.

All data collected by GreenShot is stored and accessible at the user's convenience using the cloud-based GreenShot user Interface. This interface allows users to shoot fluid levels, pressure buildups and acoustic velocity shots on demand in addition to the automated shots being provided. This interface provides operators with reservoir and downhole data sets that can normally only be achieved through the use of downhole gauges. While accurate, downhole gauges tend to be expensive to install and difficult to maintain.

To put some numbers to this, installing a permanent and wired downhole gauge system on a rod pump well can cost upwards of $29,000 by the time the gauge, cabling and clamps are accounted for. This is not a system that is intended for multiple uses over time, as each of the components have a life span of two to four years at best.

Compare this to a permanent surface system like the GreenShot, which has a one-time purchase price of $14,500, no downhole equipment and little maintenance or service required over time. Additionally, this system will have the ability to provide advanced control algorithms when paired with the manufacturers POC technology.

Flow Path:

As seen in Figure 1, as casing gas and fluid exits the wellbore at the surface, it is forced into a two-inch, schedule 80 pipe that will then flow typically five to 15 feet on surface towards the GreenShot inlet. From there, the casing flow will enter the GreenShot system, encounter a closed flowline bypass valve and be forced upward towards the shooting valve.

Continuing through the system, the gas and fluid will encounter a gas relief valve designed to relieve at 50 psi plus flow line pressure. In other words, if casing pressure is 100 psi, pressure cannot relieve through the relief valve until casing pressure hits 151 psi.

This relief path will be closed unless a blockage has occurred downstream in the system, in which case pressure will relieve through the gas relief valve.

Continuing, gas and fluids flow through a Y strainer designed to capture any well solids or trash and prevent them from damaging the systems end devices. Once through the Y strainer, flow continues passed a GreenShot sensor used to monitor casing pressure and an acoustic transducer used to measure fluid level kicks and collar counts.

Flow then continues through the normally open shooting valve, which serves as the wave or energy creator of the system.

Once through the shooting valve, flow continues through the surge tank that allows for amplified shot implosions, exiting out a two-inch check valve and dumping back into the flowline to be co-mingled with tubing on its way to the facility.

Introduce the 7 Key Data Points and Their Importance in Optimization Practices:

With each Fluid Level Shot, GreenShot provides the end user with seven key data points as outlined below.

Fluid Level Above Pump:
The fluid level is used to compute parameters that indicate each individual well's production potential. It is also known as gaseous fluid level, as it is a column of fluid often entrained with a varying amount of gas being produced up casing. With traditional rod pump applications, a pump off controller is used to

determine, among many things, pump fillage, which is an indication of how full the pump is. This helps operators slow down or stop the unit if the well starts pumping off to prevent damage to the rod string, pump and entire installation. But with many wells set to run 24 hours a day, there is no way for the operator to know if they are effectively drawing the well down or if more production is to be had. This is exactly the problem that a continuous fluid level system answers. Monitoring the fluid level gives the operator the knowledge of how they are drawing the well down as well as the opportunity to optimize fluid extraction.

PIP:
Pump intake pressure (PIP) has historically been a very difficult data set to acquire in an accurate manner outside of Electrical Submersible Pump (ESP) wells with working downhole gauges.
As for rod pumps, PIP can be calculated from downhole data, but this calculation remains difficult - and problematic at best - if any amount of wellbore deviation is present. Additionally, this method is not accounting for dynamic casing gas rates effecting the fluid gradient, which has a large effect on PIP calculations accuracy.

The importance of an accurate PIP cannot be understated as it weighs heavily on optimization and well-design decisions. If the PIP is high, more production is likely available. If the PIP is low, the well is likely producing at capacity at the pump's present setting depth.

Fluid Gradient:
As one of the key components, fluid gradient is defined as the weight of the fluid column above seating nipple (SN) in psi per foot. Fluid gradients are extremely dependent on the casing gas rates, which are highly dynamic throughout the day. Trending this data over time is essential to understand well dynamics and allows better understanding of pump and gas separator efficiencies, gas rate changes and drawdown effectiveness. For reference, typical fluid gradient values are 0.44 psi/ft for fresh water, 0.5 psi/ft for salt water brine and 0.3 psi/ft for a mixture of oil, water and gas.

As fluid gradients fall below .2 psi per foot, separators and pumps struggle to produce the gas entrained liquid. Casing gas production is dynamic throughout the day. As more and more gas moves upward in casing through the fluid column or fluid level, the weight of this fluid column becomes progressively lighter. The more gas entrained in the fluid column, the more compressible it becomes. Gas interference becomes an issue at the pump as gas must expand off the standing valve on the upstroke to allow reservoir fluid in, and must be compressed on the downstroke before the traveling valve can unseat and move fluid into tubing. In short, with a fluid gradient of .07psi/ft., it does not matter what gas separator is in the hole because gas temporarily overcomes the pump and gas interference occurs. Even though the fluid level is high, it is common for controllers to mistake gas interference for pump off and shut down the well, therefore wasting production. This poses an optimization opportunity, forcing operators to choose between pumping through this scenario or shutdown.

Produced Casing Gas:
This data point measures the amount of casing gas produced at the well based on most recent pressure buildup. This number is normalized over a 24-hour period to ensure the highest point of accuracy. It should always be less than the well's total gas production, as gas produced up the tubing is not included in the calculation.

Acoustic Velocity:
Acoustic velocity shots utilize a collar-counting algorithm to measure the rate at which the shot is moving through the casing column. Acceptable ranges for acoustic velocity are 700 to 1,300 feet per second. In order to obtain consistency in acoustic velocity, it is recommended that this shot only be performed once per week. Additionally, subtle changes in acoustic velocity are thought to accompany production changes from zone-to-zone in multiple-completion wells. For acoustic velocity to experience substantial changes over time, the gas or fluid properties produced through the given wellbore would have to fluctuate quite drastically and the only scenarios where this occurs is in dynamic methane ($CH4$) or carbon dioxide ($C02$) production environments.

Casing Pressure:
The pressure reading in psi within the casing during the last shot.

Gas Free Fluid Level Above Pump:
Indicates the gas-free fluid level that is above the pump. Also referred to as dead oil or dead fluid.

GreenShot Downhole Event Recognition:

This automated fluid level technology can be used to identify the following well conditions:

• Simplified Gas Separator Efficiency Comparisons – studies – Resolve's difficulties in pumping through gas interference (overwriting POC shut down):

a. GreenShot provides a produced casing gas rate. When total gas rates and casing gas rates are known the difference between the two values represents how much gas is moving through the pump, BHA and tubing string. This allows the end user to compare the success of various gas separators on an even playing field for the first time. Comparing two gas separators is often difficult as no two wells are similar. Varying production rates, water rates, bubble points and hydrostatic pressure are all factors that can affect these systems. Yet when the end user can compare how much gas in moving through casing on each well/bha system, better optimization is possible.

• Flumping Identification:

a. Flumping is defined as a well condition where the well is flowing fluid up the backside (casing) as well as producing fluid up the tubing. This extra production being pushed up the back side is not accounted for and makes production allocation difficult. New conversions and wells carrying high fluid levels tend to flow up the back side quite often and will stop as the well settles down over time. Identifying these scenarios remotely can help in regard to:
    i. Proper production allocation for allocated facilities
    ii. Identifying wasted chemical batch treatments down backside. When a well is flowing fluid up casing or carrying a high fluid level above pump, the likelihood of getting the batch treated or slip streamed chemical treatment from surface, down casing to the pump is minimal at best. When a flumping condition is identified it would be a good opportunity for the end user to pause the chemical treatment until the well settles down over time. Pumping chemical down the backside during a flumping condition is just an expensive way to treat the flowline.

b. An example of how GreenShot identifies flumping conditions can be referenced in Figure 5 below.

OPTIMIZATION METHODOLOGY WITH GREENSHOT

During this process, erroneous values for PIP and gas free fluid levels result in the design program concluding an overloading condition in part of the system, therefore recommending it unsafe to pursue more production from the system.

The recommended use of the GreenShot system calls for the end user to install the system and monitor the data coming in over a period of approximately 2 weeks while avoiding any optimization changes during this time. This allows the end user to get a clear picture of how the well is performing under current conditions but more importantly allows for the acquisitions of the 7 key data points that will provide the operator with the information needed to re-run the rod design based on current conditions to identify true equipment loading. It is at this point where the path forward becomes clear.

PIP, Fluid Level Above Pump, the weight of that fluid column and the gas being produced up casing all play a large role in the loading algorithms in today's rod design programs. A higher fluid level above pump equals less load due to the effects of buoyancy on the system. More gas moving through that given fluid column leads to lighter fluid gradients and higher equipment loading on the system. Systems are designed using predictive software with pumped off condition, which represents the worst-case scenario for fluid extraction and power requirements.

These systems are often designed with estimations or outdated fluid level and PIP data being entered but more importantly in a pumped off state. The basic idea here is to design for a pumped off condition where there are no buoyancy effects reducing the loads felt by the pumping unit, structure, and sucker rods. Fast forward to when the well is being produced and these same equipment loading numbers are being referenced yet a pumped off condition has not been achieved.

True design represents a rod design using current, known well conditions, i.e. instantaneous fluid level.

True loading is defined as the real equipment loading calculated using instantaneous fluid level data.

PO Rod Design vs True Rod Design:

Reference figures 7 and 8 below. Figure 7 shows the current and existing rod design in place at the time of GreenShot installation which was ran based on a pumped off condition of 551 PIP. This is a common practice when running rod designs and planning for a conversion to SRP, cf. [1, 3, 8]. Running a design in a pumped off condition achieves the highest equipment loading the system should ever see. However, when producing a dynamic well, true loading is needed to understand all optimization thresholds. With a GreenShot system in a place, true fluid level above pump is known at any given time. With this data the end user can then re-run the design based on current conditions to understand the optimization options available at that time.

Figure 8 was based on the current producing conditions of 2553 PIP which represented a 7,000' fluid level above pump. Table 1 clearly shows the effects a fluid level has on a producing well and its equipment loading limitations:

Equipment List	Loading w/ 551 PIP	Loading with 2553 PIP	Results
Gear Box Loading	117.3%	106%	11.3% reduction
Structure Loading	93.6%	75.6%	18% reduction
Rod Taper Loading	70%	49%	21% reduction
	68%	48%	20% reduction
	74%	52%	22% reduction
	29%	15%	14% reduction

Table 1: Difference in loading using 551 PIP and 2553 PIP.

From Table 1, gearbox loading decreases from 117.3% to 106% or 11.3% reduction when using current PIP value of 2553 psi compared to original PO design. Structure loading decreases 18% and rod taper loading decreases an average of 19% across all tapers.

When drawing down a fluid level on a dynamic horizontal well, gas interference scenarios are expected as previously mentioned. To model this and ensure no overloading or damage to the system is taking place, the rod design is run with 60% pump fillage on gas interference cards. Table 2 along with Figures 9 and 10 showcase how additional production can be achieved in a high fluid level with gas interference scenario due to plunger over travel on the upstroke caused by buoyancy.

Units	60% Fillage w/ 551 PIP	60% Fillage w/ 2,553 PIP	Results
DH Stroke Length	131.5"	172.6"	31% increase
Fluid Load	7,619 Lbs.	2,803 Lbs.	4,816 Lbs. reduction
Total Fluid Production	356 BPD	468 BPD	31.46% increase

Table 2: Difference in downhole stroke, fluid load and total fluid production when comparing 553 PIP and 2553 PIP.

Table 2 shows that with the current PIP value of 2553 psi, the downhole stroke is increased by 31% and the fluid load is decreased by 4,816 lbs for a total increase in production of over 31%.

By having the ability to gather true and current downhole conditions, 2 key actions are able to take place. One, a rod design can be re-ran based on current conditions to ensure no damage to the system will take place by pumping through the gassy scenarios to come. And two, pump fillage or expected pump fillage in the gas interference scenarios can be entered to further verify no damage to the system.

With these two facts verified, the well can now be produced in a more effective manner than previously thought possible resulting in not only longer run times but potentially longer stroke lengths, both of which will lead to increased production and drawdown over time.

Without this information, we do not have the ability to confidently produce todays wells in the manner that is necessary to draw these wells down to a pumped off state in a timely fashion.

<u>RESULTS: HOW DOES GREENSHOT PAY FOR ITSELF AND IN HOW LONG?</u>

In this section, optimization technique aiming at extracting every single drop of production is discussed as well as a field case study showing a dramatic increase in production using GreenShot and the return in investment possible.

Fluid Dynamics Brought to Light Using GreenShot:

Dynamic difference in fluid level shots taken in short intervals.

Essentially it is difficult to argue with a fluid level pick as it is measured data. Annulars are known, time is known, acoustic velocity or speed of the pressure wave is known. The kick pick is simply the signature created when the wave crashes into the top of fluid. Monitoring these kicks 10 times a day has produced much more dynamics than what was expected.

The pattern goes as follows, a calm period arises in the reservoir meaning casing gas rates settle down, the pump fills, efficiency rises and the fluid level reduces often times thousands of feet over a period of several hours.

With a much shorter column of fluid above pump, the hydrostatic head on the reservoir has been reduced by hundreds, maybe 1000+psi. This is enough for one or several of the zones within the lateral to unload.

At this point in time, the casing gas rates climb quite dramatically and reservoir fluid unloads into the fluid column bringing the fluid level up thousands of feet back to its original position, see Figure 11 and 12. The fluid gradient is reduced drastically due to the excess gas causing gas interference at the pump, the drive slows the well down or pumps off on fillage. Fluid level continues to climb, choking out the reservoir, reducing casing gas rates and the well is right back to where it began the day. This occurrence was captured multiple times on various horizontal wells in the Permian Basin.

The GreenShot gives the user the knowledge and timing of this occurrence. With this understanding on each well true well optimization can begin through understanding of erratic behavior that takes place during gas interference scenarios.

Gas rates in casing can fluctuate drastically in just a 15-hour period. Certainly a “slug” of gas is identified in this data however a casing gas rate fluctuating from 2 mcf to 130mcf will have a dramatic effect on the fluid column as well. A well suffering from consistent gas interference scenarios or even slugging tendencies is often also carrying quite a large fluid level above pump. Drawdown and pump efficiencies become an afterthought as no data is available to show the end user that more production can be had without damaging the system even in a poor fillage environment.

Getting Every Drop of Production Without Overloading the System:

The GreenShot was installed on a rod pumped pad well in early 2020. This was a horizontal application producing the Wolfcamp reservoir with a seating nipple depth of 8788'. The well was equipped with a 640-365-168 pumping unit, set in the middle stroke, 1.75" pump, a Mother Hubbard style gas separator and an integrated variable frequency drive. Around the time of installation, this well was running at 24hrs./day at 4.5 SPM producing roughly 77 Oil, 76 water and 24 MCF of gas while carrying a gaseous fluid level above pump of ~7000'. Pump fillage was a steady 85-95% at the time of install and the well had been producing on rod pump for roughly 1 year.

With a fluid level above pump of 7000', consistently high pump fillage and running 4.5 SPM, this well had more production capability. At this point the question became can additional production be captured without damaging the system? Using GreenShot, WellWorx team can make operational control suggestion based on true loading and true design to maximize drawdown and production, with consideration for current reservoir dynamics.

With weeks' worth of casing gas rates, PIP's, and fluid levels in hand, this data can be entered into a rod design program which can then recalculate the true and current equipment loading of the system by accounting for the now known PIP and fluid level above pump. In this case we were able to verify we would not overload any piece of the system or begin to buckle rods until a pumping rate of 9SPM was achieved or if fluid level above pump was to fall below ~1500'.

With this information acquired, we were able to produce this well in an entirely new manner. The data that the GreenShot is providing allows us to confidently produce a well more aggressively than we could otherwise. In this scenario over the period of the next year this well was sped up from 4.5-6.2 and eventually 7 SPM. These speed increases were a topic of many discussions due to the gas interference issues we knew would follow. As the well sped up, the system was much more effective in drawing the well down early on. As the hydrostatic head continued to be reduced, casing gas rates increased to roughly 6 times their previous rates at the slower SPM.

Today this same well is now producing 144 Oil, 182 Water, and 191 MCF of total gas at 7 SPM and 85-95% pump fillage over time and 24 hour run times. Figure 6 shows a comparison of before and after GreenShot optimization production data.

This project took longer than expected due to battery allocation issues, down time and time required to work with new technology. Based on production improvement, if the above-described changes had been carried out immediately, the GreenShot system could have paid for itself in roughly 1.74 days. This calculation based on current oil and gas prices when applied to the costs of installation and the system paired with the production increases seen over time.

In summary, before GreenShot was installed on this well a single pressure buildup, fluid level and questionable PIP were being acquired once every quarter or 6 months. This greatly restricted the production capability on this well, especially since maintaining high speed production while limiting shutdowns and slowdowns during gas interference is not common practice for operators.

This well experienced many changes over the last year and a half and each of these operating decisions were made possible by being able to reference the 7 key data points provided from the GreenShot system. GreenShot enabled a significant increase oil, water and gas production.

CONCLUSIONS

Instincts and lessons learned while optimizing vertical rod pumped systems have carried over to today's highly dynamic horizontal applications and are limiting production capabilities. The same production optimization techniques are used on vertical and highly dynamic wells with little success.
More information is needed than dynograph cards or current automation systems can accurately provide, such as fluid level above pump, fluid gradient and casing gas rates must not only be gathered but gathered on a much more frequent basis than our industry is used to. GreenShot's data paired with our current cards and control methods can allow us to make optimization and well control decisions that we previously would not have been comfortable with due to lack of data and information.

Monitoring the conditions and capturing the data mentioned in this paper on a consistent basis throughout a given field is the next necessary step needed to improve the industries current optimization practices. Without this type of data, the industry will continue to extend this difficult point in the life of the well by pumping off or slowing down to protect equipment.

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FIGURES

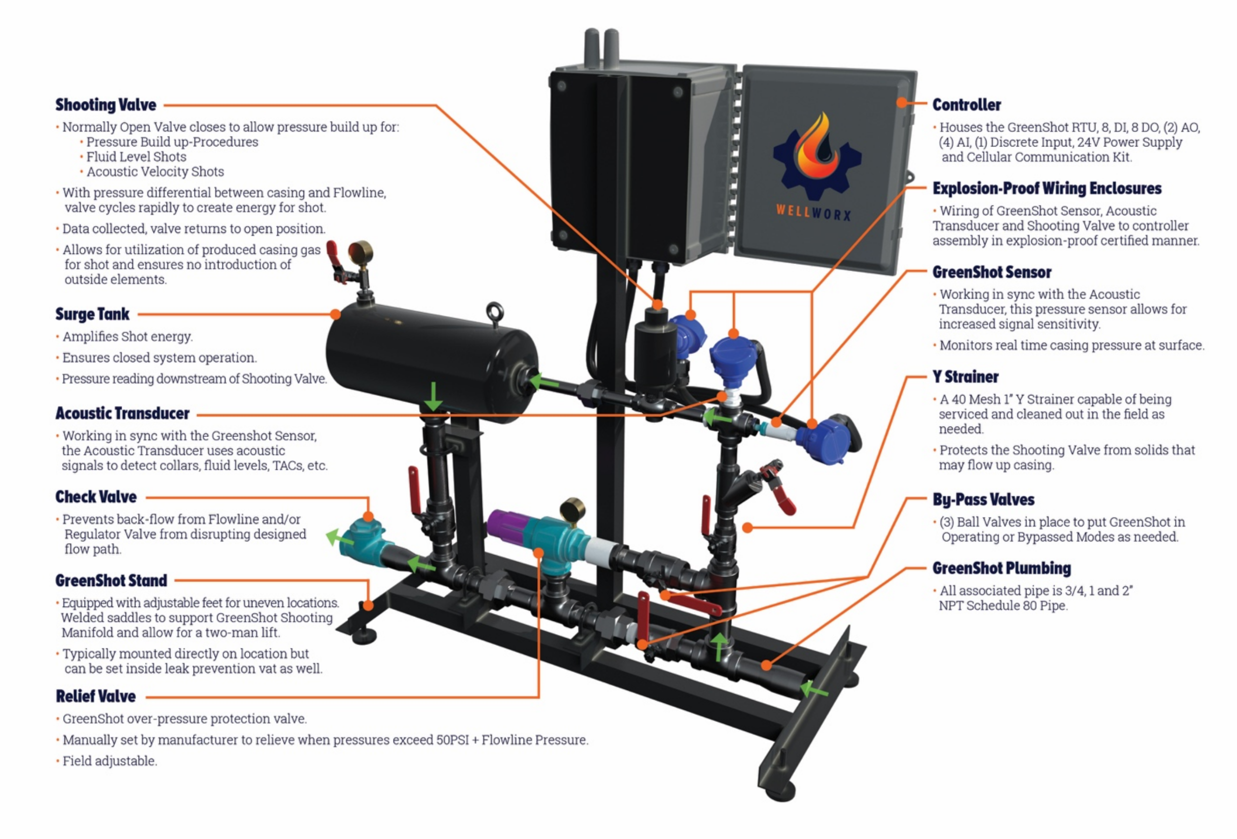


FIGURE 1: GreenShot Shooting Manifold

FIGURE 2: Picture of the GreenShot Interface

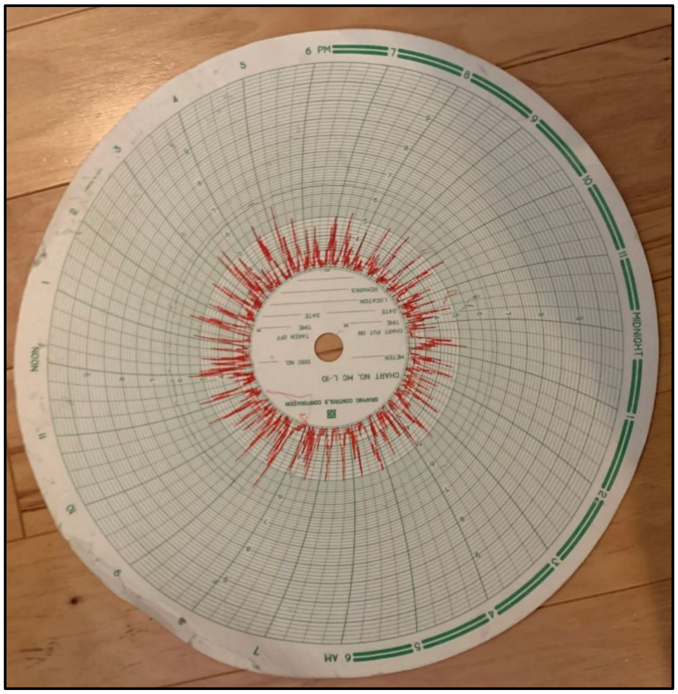


FIGURE 3: Barton Chart Showcasing Erratic Gas Production in a 24 hr. Period

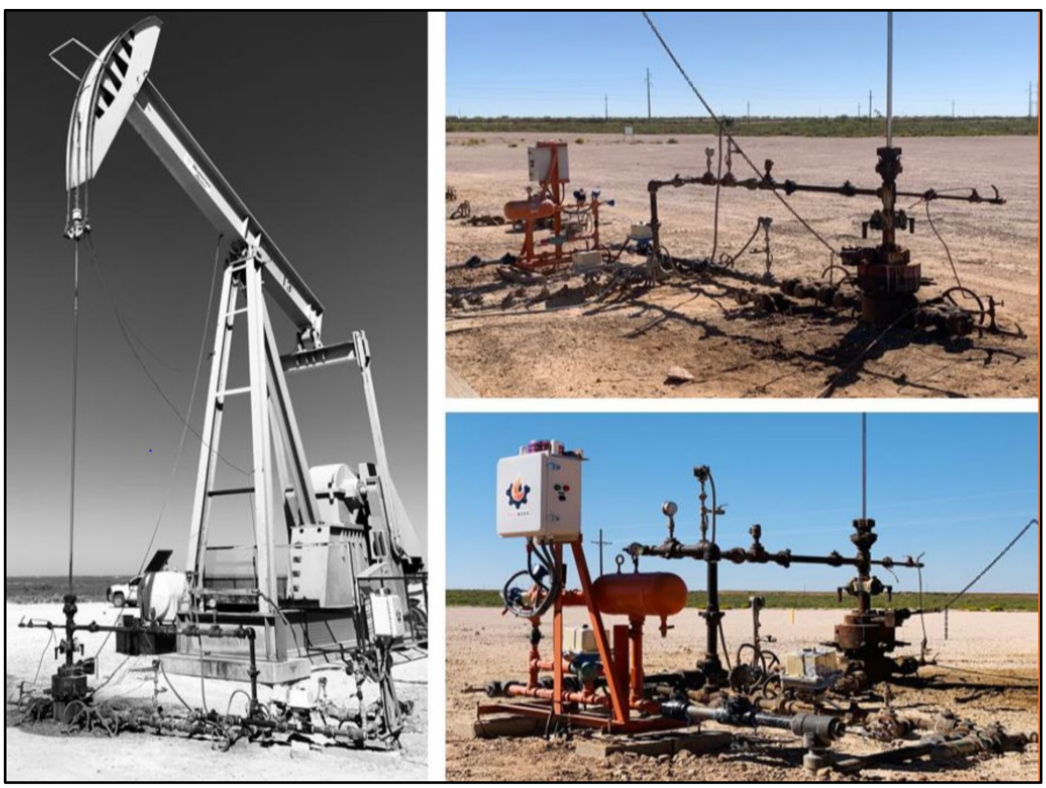


FIGURE 4: GreenShot System Installed on Rod Pump Application

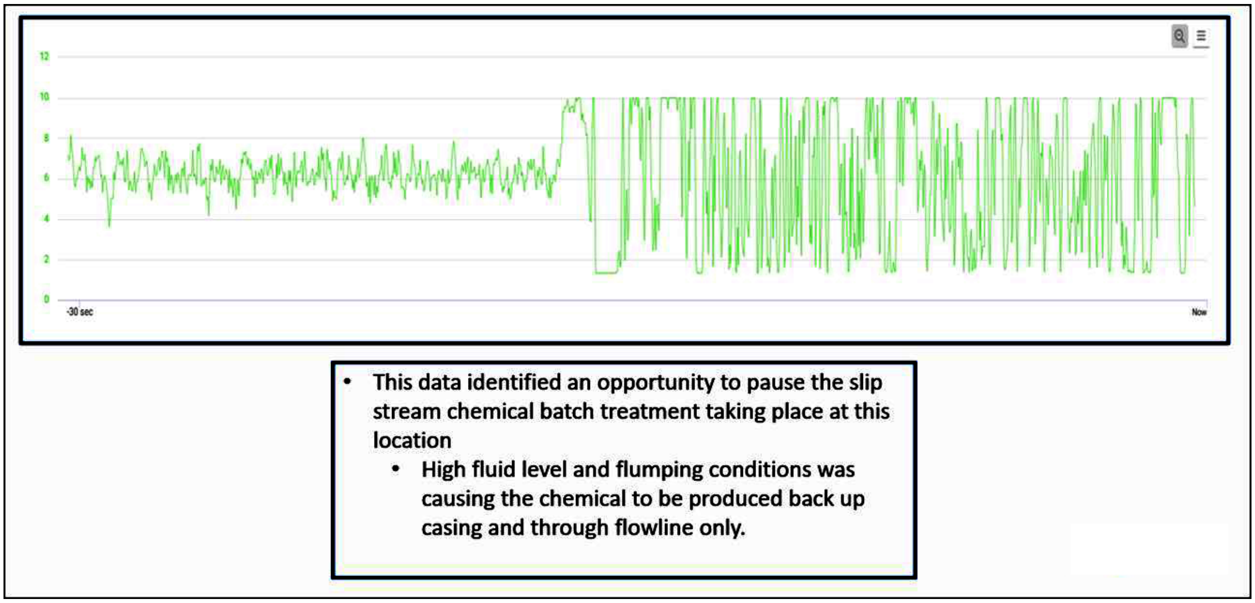


FIGURE 5: A rod pumped well caught transitioning from a normal gas flow to flumping condition.

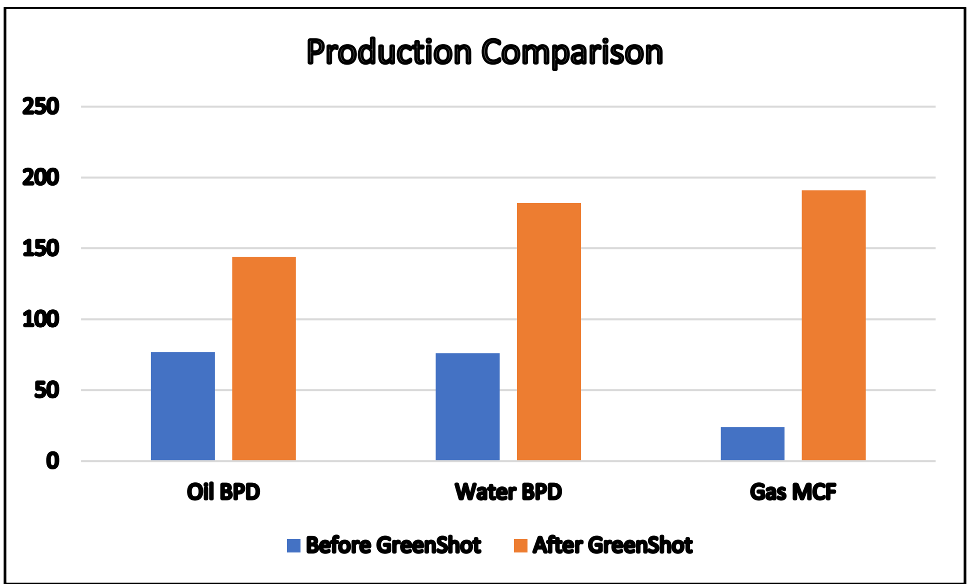


FIGURE 6: Production comparison before and after GreenShot in field case study example.

SROD v8.6.0 - PREDICTION OF ROD PUMPING SYSTEM PERFORMANCE

** PRIME MOVER **

Mfgr and Type	: Nema D Motor75 hp (Recommended)		
Max Speed (rpm)	: 1207	Speed Variation (%)	: 7.8
Min Speed (rpm)	: 1113	Cyclic Load Factor	: 1.247
Power Required (hp)	: 56.79	Peak Regenerative Power (hp)	: -10.35
Motor Load (% of Rating)	: 75.7	Prime Mover Output (hp)	: 45.53
Sheave Ratio (Unit/ Prime Mover)	: 5.095		

** PUMPING UNIT **

Mfgr and Type	: LUFKIN C640-365-168 (C'WISE)		
Actual Max Load (lbs)	: 34173	Actual Min Load (lbs)	: 11451
Average Pumping Speed (SPM)	: 7.58	Max Load (% of Rating)	: 93.6
Polished Rod Power (hp)	: 40.98	Unit and Drive Train Loss (hp)	: 4.55
Computed Surface Stroke (in)	: 146.9		

** SUMMARY OF REDUCER LOADING **

	IN BALANCE
Max Torque (m in-lbs)	750.9
Min Torque (m in-lbs)	-78
CounterBalance Moment (m in-lbs)	1748
Counterbalance Effect (X100 lbs)	232.87
Percent of Reducer Rating	117.3

** ROD LOADING **

	Diameter (in)	Length (ft)	Modulus (MM psi)	Fr Coeff	Guides (Counts/rod)	Rod Loading (%)
1)	1.25	487	7.2	0.2	N (0)	70
2)	1.25	3463	7.2	0.25	M (6)	68
3)	1 *	4300	30.5	0.25	M (4)	74
4)	1.5	550	30.5	0.2	N (0)	29

* Requires slimhole couplings

R&M PPS - Stealth XL guide weights has been considered

Max Stress (surf.) (psi) : 27765 Min Stress (surf.) (psi) : 9413

Rod Load as % of John Crane Series 200 Guideline: 70

** DOWNHOLE PERFORMANCE **

	Stroke (in)	BPD at 100% eff.	BPD at 85% eff.
Gross:	143.1	387 (24h/d)	329 (24h/d)
Net:	142.6	386 (24h/d)	328 (24h/d)

Tubing Stretch (in)	: 0	Lost Displacement (bpd)	: 0
Loss Along Rod String (hp)	: 18.65	Pump Power (hp)	: 22.33
Tubing Size (in)	: 2.875	Tubing Anchor Location (ft)	: 8800
Pump Spacing Guide (in)	: N/A	Pump Fillage (%)	: 100

** Non-Dimensional Variables **

Fo/S/Kr : 0.39 N/No' : 0.4

** OTHER BASIC DATA **

Reducer Rating (in-lbs)	: 640	Crank Rotation	: (C'WISE) - Well to right
Overall Speed Ratio	: 152.8	Rod Damping Factors (up/down)	: 0.05 / 0.15
Min/Max Tubing Head Press. (psi)	: N/A	Buoyant Rod Weight (lbs)	: 17516
Total Load on Pump (lbs)	: 7619	Pump Bore Size (in)	: 1.75
Pump Load Adjustment (lbs)	: 0	Tubing Gradient (psi/ft)	: 0.395
Pump Depth (ft)	: 8800	Pump Intake Pressure (psi)	: 551
Pump Friction (lbs)	: 900	SV Load (lbs)	: 16516
TV Load (lbs)	: 26135		

FIGURE 7: Original Rod Design to bring system online

SROD v8.6.0 - PREDICTION OF ROD PUMPING SYSTEM PERFORMANCE

** PRIME MOVER **

Mfgr and Type	: Nema D Motor60 hp (Recommended)		
Max Speed (rpm)	: 1229	Speed Variation (%)	: 10.5
Min Speed (rpm)	: 1100	Cyclic Load Factor	: 1.553
Power Required (hp)	: 50.01	Peak Regenerative Power (hp)	: -31.55
Motor Load (% of Rating)	: 83.4	Prime Mover Output (hp)	: 32.21
Sheave Ratio (Unit/ Prime Mover)	: 5.102		

** PUMPING UNIT **

Mfgr and Type	: LUFKIN C640-365-168 (C'WISE)		
Actual Max Load (lbs)	: 27592	Actual Min Load (lbs)	: 11364
Average Pumping Speed (SPM)	: 7.59	Max Load (% of Rating)	: 75.6
Polished Rod Power (hp)	: 28.99	Unit and Drive Train Loss (hp)	: 3.22
Computed Surface Stroke (in)	: 146.9		

** SUMMARY OF REDUCER LOADING **

	IN BALANCE
Max Torque (m in-lbs)	678.6
Min Torque (m in-lbs)	-226.2
CounterBalance Moment (m in-lbs)	1600.9
Counterbalance Effect (X100 lbs)	212
Percent of Reducer Rating	106

** ROD LOADING **

	Diameter (in)	Length (ft)	Modulus (MM psi)	Fr Coeff	Guides (Counts/rod)	Rod Loading (%)
1)	1.25	487	7.2	0.2	N (0)	49
2)	1.25	3463	7.2	0.25	M (6)	48
3)	1 *	4300	30.5	0.25	M (4)	52
4)	1.5	550	30.5	0.2	N (0)	15

* Requires slimhole couplings

R&M PPS - Stealth XL guide weights has been considered

Max Stress (surf.) (psi) : 22403   Min Stress (surf.) (psi) : 9342

Rod Load as % of John Crane Series 200 Guideline: 49

** DOWNHOLE PERFORMANCE **

	Stroke (in)	BPD at 100% eff.	BPD at 85% eff.
Gross:	169.3	459 (24h/d)	390 (24h/d)
Net:	168.8	458 (24h/d)	389 (24h/d)

Tubing Stretch (in)	: 0	Lost Displacement (bpd)	: 0
Loss Along Rod String (hp)	: -5.22	Pump Power (hp)	: 34.21
Tubing Size (in)	: 2.875	Tubing Anchor Location (ft)	: 8800
Pump Spacing Guide (in)	: N/A	Pump Fillage (%)	: 100

** Non-Dimensional Variables **

Fo/S/Kr : 0.14   N/No' : 0.4

** OTHER BASIC DATA **

Reducer Rating (in-lbs)	: 640	Crank Rotation	: (C'WISE) Well to right
Overall Speed Ratio	: 153.1	Rod Damping Factors (up/down)	: 0.05 / 0.15
Min/Max Tubing Head Press. (psi)	: N/A	Buoyant Rod Weight (lbs)	: 17516
Total Load on Pump (lbs)	: 2803	Pump Bore Size (in)	: 1.75
Pump Load Adjustment (lbs)	: 0	Tubing Gradient (psi/ft)	: 0.395
Pump Depth (ft)	: 8800	Pump Intake Pressure (psi)	: 2553
Pump Friction (lbs)	: 900	SV Load (lbs)	: 16516
TV Load (lbs)	: 21319		

FIGURE 8: Same design re-ran with 2553 PIP

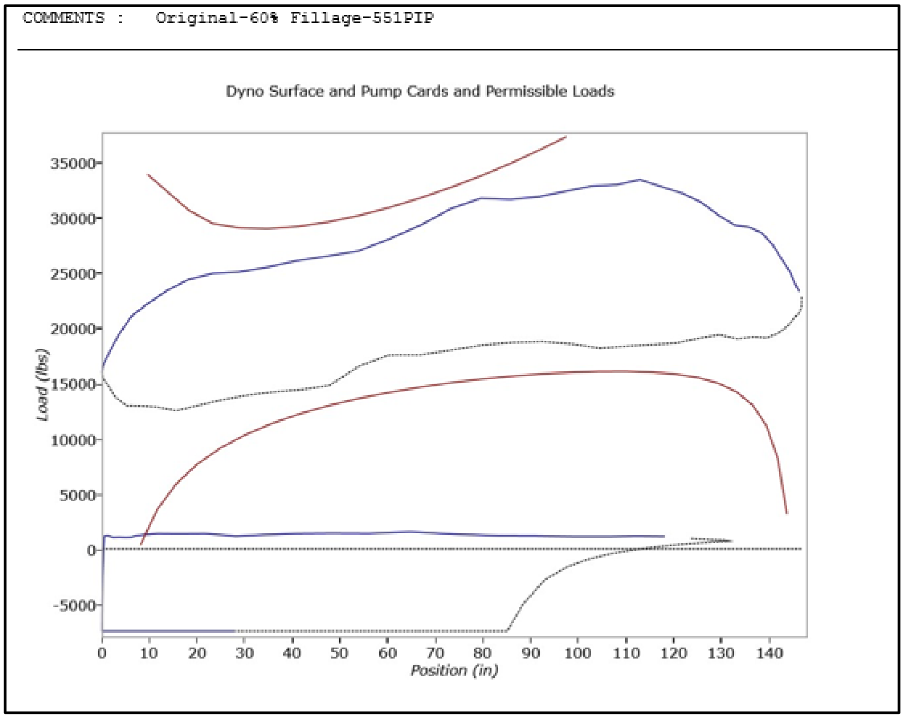


FIGURE 9: 551 PIP, 60% Fillage showcasing shorter dh stroke.

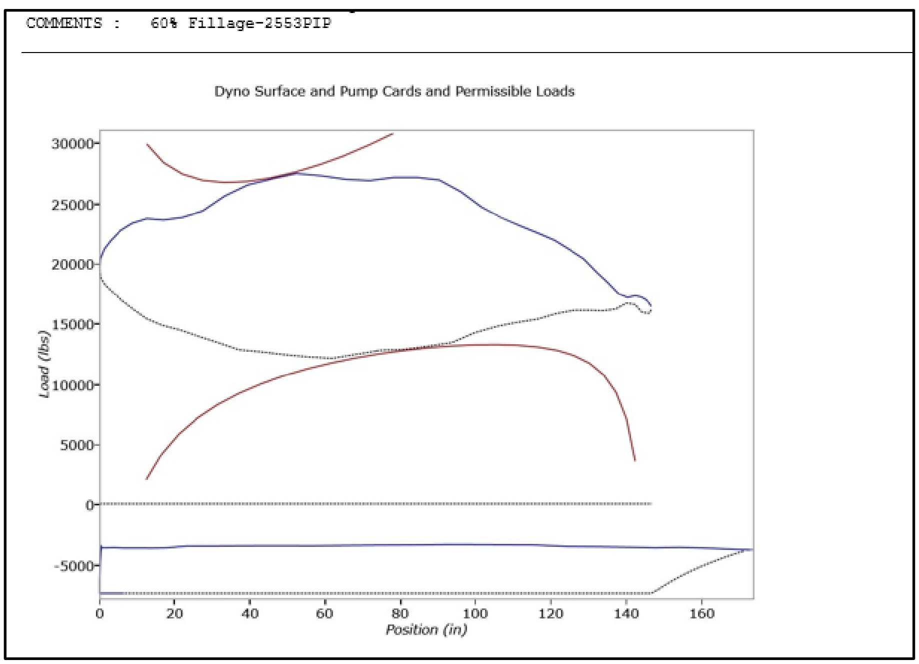


FIGURE 10: 2553 PIP, 60% Fillage showcasing longer dh stroke.

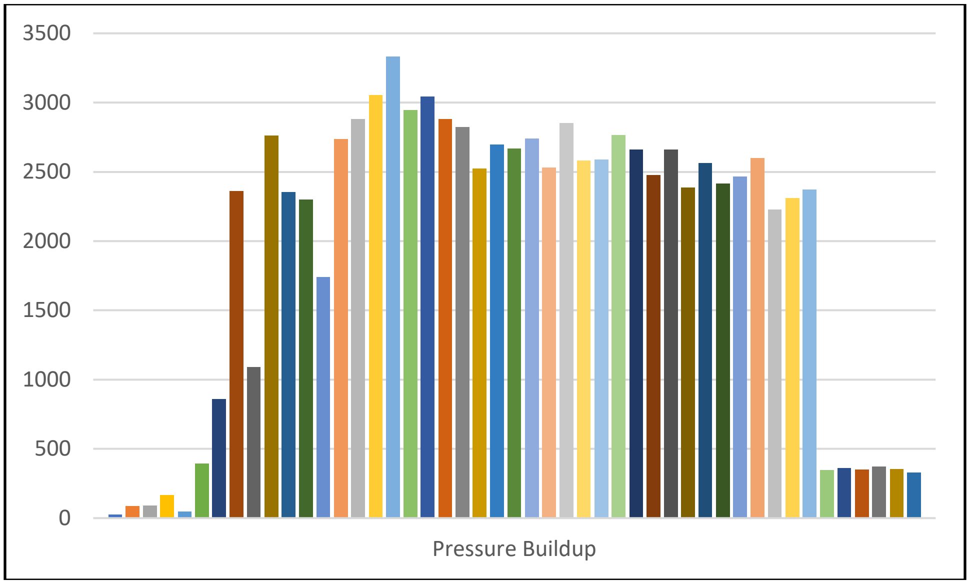
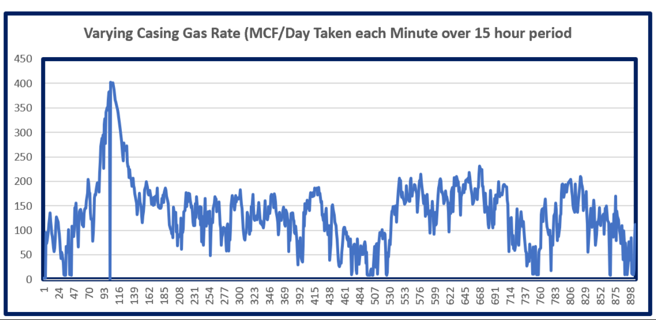


FIGURE 11: Casing gas rates from Pressure Buildups every 10 minutes for 12 hours with fluid level increasing from 2,704 ft to 7,611 ft.

Dynamic ESP Casing Gas Rates Captured via MVT



Timestamp	Comparable GS Flow Rates
5/12/2021 18:19	2.708403457
5/12/2021 18:20	2.802735753
5/12/2021 18:21	2.860828042
5/12/2021 18:22	2.782901488
5/12/2021 18:23	95.99070311
5/12/2021 18:24	72.95080662
5/12/2021 18:25	79.11791325
5/12/2021 18:26	98.47662807
5/12/2021 18:27	113.6525345
5/12/2021 18:28	123.5259819
5/12/2021 18:29	135.8888519
5/12/2021 18:30	119.2993891
5/12/2021 18:31	107.2958171
5/12/2021 18:32	93.5522747
5/12/2021 18:33	87.55685627
5/12/2021 18:34	63.74472499
5/12/2021 18:35	56.87545896
5/12/2021 18:36	63.33862245
5/12/2021 18:37	83.05587888
5/12/2021 18:38	108.6962628
5/12/2021 18:39	127.170428
5/12/2021 18:40	123.4034371
5/12/2021 18:41	117.2667682
5/12/2021 18:42	102.9419267
5/12/2021 18:43	93.10886264
5/12/2021 18:44	77.44584024
5/12/2021 18:45	55.14976323
5/12/2021 18:46	42.49020875
5/12/2021 18:47	55.75534165
5/12/2021 18:48	50.37517905
5/12/2021 18:49	33.89851123
5/12/2021 18:50	8.849455789
5/12/2021 18:51	8.44846487
5/12/2021 18:52	8.46319221

Timestamp	Comparable GS Flow Rates
5/12/2021 20:02	401.7685793
5/12/2021 20:03	400.4146671
5/12/2021 20:04	399.6475124
5/12/2021 20:05	401.1078787
5/12/2021 20:06	394.1667509
5/12/2021 20:07	386.820631
5/12/2021 20:08	376.1866808
5/12/2021 20:09	366.2112665
5/12/2021 20:10	362.1615171
5/12/2021 20:11	351.2250137
5/12/2021 20:12	346.5493226
5/12/2021 20:13	339.3072724
5/12/2021 20:14	330.6685638
5/12/2021 20:15	321.9559121
5/12/2021 20:16	312.0459437
5/12/2021 20:17	302.9605508
5/12/2021 20:18	281.3659143
5/12/2021 20:19	267.3262239
5/12/2021 20:20	252.6086426
5/12/2021 20:21	241.6984892
5/12/2021 20:22	278.6292887
5/12/2021 20:23	268.0525017
5/12/2021 20:24	266.037519
5/12/2021 20:25	263.0005503
5/12/2021 20:26	272.8787827
5/12/2021 20:27	239.222188
5/12/2021 20:28	229.5924568
5/12/2021 20:29	230.5603909
5/12/2021 20:30	207.494638
5/12/2021 20:31	224.4757247
5/12/2021 20:32	210.094192
5/12/2021 20:33	202.6232958
5/12/2021 20:34	189.9530554
5/12/2021 20:35	201.1051226
5/12/2021 20:36	206.5196872
5/12/2021 20:37	191.0044813
5/12/2021 20:38	185.9071469
5/12/2021 20:39	174.5528841
5/12/2021 20:40	161.5864313
5/12/2021 20:41	155.3929317

FIGURE 12: Dynamic Casing Gas Rates Captured