EXPLORING INNOVATION IN GAS FLOW MANAGEMENT FOR ENHANCED ESP EFFICIENCY AND REDUCED DOWNTIME - A COMPREHENSIVE REVIEW OF LESSONS LEARNED AND CASE STUDIES

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ABSTRACT
This paper builds upon last year's presentation, which featured a case study showcasing the application of gas handling technology in the Midland Basin. With over 200 installations in the Permian Basin, this document expands on the insights gained from various applications, providing additional data that reinforces the operational principles and results presented in the previous year. In this paper, we delve into the intricate physical principles governing the gas handler's functionality in regulating free gas flow before reaching the ESP intake. Through the presentation of three case studies, we illustrate how these adjustments have significantly enhanced project profitability.

The first case study examines a Delaware well completed in the Bone Spring, notorious for historical gas and sand challenges. The regulator was installed alongside the second ESP, with an expected liquid production of 1,200 BFPD and a GLR of 1,000 SCF/STB. The second case study focuses on a well completed in the Middle Spraberry producing 375 BFPD and a GLR of 800 SCF/STB. Considering the production rates, a rod pump conversion was contemplated. The final case study explores a well also completed in the Middle Spraberry, producing 370 BFPD and a GLR of 2,400 SCF/STB with a history of sand and gas issues. Initially considered for gas lift conversion, the lack of facilities led to the reinstallation of the ESP to postpone the conversion to a rod pump and maintain higher production. In all case studies, we evaluate sensor parameters, presenting the before-and-after scenarios of production rates and drawdown.

As unconventional reservoir development matures, the challenges related to well production increase. In recent years, there has been a significant uptick in the discussion surrounding gas slugging and gas-related issues. This paper compiles experiences from several installations with this technology and provides analysis of the ESP performance. This groundbreaking technology represents a pioneering approach by regulating gas below the pump's sensor, distinguishing itself as the first of its kind in its class.

GAS SLUGS: PROBLEM DESCRIPTION

The decline in bottomhole pressure caused by fluid production generates changes in flow regimes within the casing. In conventional reservoirs, these changes take time; however, as observed in the past decade, unconventional reservoirs undergo faster transitions due to accelerated bottomhole pressure decline. These rapid changes can occur in less than a year and affect the performance of artificial lift systems. Typically, the rate of free gas production is not high in the early production stages and does not pose a problem for Electric Submersible Pumping (ESP) systems. But due to the rapid changes described above, the amount of free gas at the bottom of the well increases, leading to gas flow as a continuous phase known as gas slugs (Figure 1).
These gas bubbles flowing with the liquid phase affect the well's liquid production in various ways, and the severity of the problem will depend on the size of the bubbles and
the type of pumping system used. Regarding the pumping system, ESPs' performance is significantly degraded when free gas is significant in the well. These gas bubbles can cause excessive motor overheating due to poor heat transfer from the motor to the surrounding medium, resulting in frequent shutdowns, short run times, and overall low liquid production (Figure 2). Frequent shutdowns and restarts

can shorten the equipment's lifespan and lead to premature failures requiring workover interventions and additional operation costs.

Regarding bubble size, various factors influence their size in multiphase flow in a production system as described above. These factors will determine the severity of the problems caused by free gas in ESPs:

1. Initial Conditions (PVT): The size of gas bubbles in multiphase flow can depend on the initial conditions of the system. For example, the reservoir pressure compared to the bubble point will determine the presence of free gas at the reservoir and the amount of free gas into the wellbore.

2. Flow Regime: The flow regime within the multiphase system plays a crucial role in determining gas bubble size. Different flow regimes, such as slug flow, annular flow, or stratified flow, have distinct characteristics and can lead to variations in gas bubble size. (Figure 3)

3. Fluid Properties: The physical properties of the gas and liquid phases, such as their densities, viscosities, and surface tensions, influence bubble size. For instance, higher gas viscosity or lower liquid viscosity can lead to smaller bubbles.

4. Pressure and Temperature: Changes in pressure and temperature can affect the phase behavior of the fluids and, consequently, bubble size. Increasing pressure can lead to smaller bubbles, while decreasing pressure may cause them to expand. Conversely, increasing temperatures cause the gas to expand and form bigger bubbles.

5. Turbulence: Turbulence in the flow can break up large gas bubbles into smaller ones. Conversely, lower turbulence levels may allow gas bubbles to coalesce and become larger (Figure 4).

6. Interfacial Forces: The forces acting at the gas-liquid interface, such as surface tension, can influence bubble size. High surface tension tends to promote the formation of smaller bubbles.

7. Flow Obstacles and Geometry: The presence of obstacles or changes in the flow line geometry can impact gas bubble size. Sudden expansions or contractions in the pipeline can lead to bubble coalescence or breakup.

8. Chemical Additives: The addition of certain chemicals, like surfactants, can alter the surface tension and interfacial properties, potentially leading to changes in bubble size.

9. Coalescence and Breakup: Gas bubbles in multiphase flow can coalesce (combine) or break up due to collision and interaction with other bubbles. Coalescence leads to larger bubbles, while breakup results in smaller ones.

The understanding of the above factors is important to mitigate the harmful effect of the free gas in the well production and extend the lifespan of the ESPs.

ESP VORTEX REGULATOR: FUNCTIONALITY & OPERATION PRINCIPLES

Given the problems caused by the free gas flow before the pump intake, the ESP Vortex Regulator is installed below the pump sensor, preventing excessive free gas flow that causes motor overheating. This purpose is achieved by conditioning the production fluid, changing the flow regime from slug to dispersed bubble. The flow regime depends on pipe diameter, fluid properties, flow velocity, and phase fraction. The Vortex Regulator utilizes different mechanisms to effectively disperse the gas phase within the aqueous phase, producing a continuous liquid phase where smaller bubbles are dispersed, known as the dispersed bubble flow regime.

The main mechanisms acting in the Vortex Regulator to produce these flow regime changes are:

1. Flow Obstacles and Changes in Geometry

2. Turbulence
3. Bubble Breakup
4. Interfacial Forces

As explained in the previous section, there are several phenomena influencing the size of gas bubbles, and the purpose of the Vortex Regulator is to combine the above principles to create the greatest dispersion of gas volume within the liquid phase. The Vortex Regulator features a section where liquid is stored by gravity. This section is known as the liquid pool. By incorporating a cup-type packer, an obstacle is created that forces gas to flow from the top of the tool to the liquid pool, where phases contract and the expansion of the gas phase is prevented before flowing to the motor. The bubbles are then dispersed by the turbulence created in the vortex and then flow through the inner tube. At the top of the tool, the Surge Valve creates a check point that increases the interfacial force between the phases, producing greater bubble dispersion. The surge valve system allows bleeding of the liquid through the surge valve to incorporate more liquid into the mixture once the fluid is in the inner tube. The set pressure of this valve is adjusted with the well column to have a greater or lesser flow depending on the amount of gas in the well. The flow path of the system is shown in Figure 5.

LESSONS LEARNED

Through the installation of hundreds of devices, different parts of the design have been analyzed based on the downhole conditions to improve the Regulator performance and maximize fluid conditioning based on the mechanisms explained earlier. The main points to consider based on these analyses are summarized below:

1. Considering gas and sand problems simultaneously: The presence of sand associated with production fluid is very common, and analyzing a problem individually without evaluating the flow of solid particles can lead to issues. The internal mechanisms of the Vortex Regulator were designed to maximize flow areas while minimizing pressure drops due to friction. With the turbulence effect created by the vortex to break gas bubbles, sand separation occurs, which if not considered, can promote sand flow towards the internal tubing and the Surge Valve (Figure 6). To address this challenge, two methods were used. One is to use tail pipes to store solids and prevent flow towards the pump. The second method involves using the nozzle, a device that allows running the Vortex Regulator without tail joints, maximizing the annular flow area towards the regulator while directing sand production towards the wellbore.

2. Surge Valve Setting Pressure: The increase in the free gas at the bottom of the well increases the amount of liquid required to generate effective dispersion and an optimal change in flow regime. To increase the available liquid volume, the internal setting pressure of the Surge Valve was modified, maintaining its primary function of controlling flow velocity using the fluid column above it while generating a bypass to the internal tubing that favors gas dispersion (Figure 7). Through this modification in high GLR wells, better results have been achieved without modifying the original length of the tool.

3. Liquid Pool Volume: Like the previous point, in wells with high GLR (>1,800 SCF/STB), the need for a greater volume of liquid within the tool to generate the expected dispersion was identified. In this case, increasing the liquid pool volume from 20' to 44' was considered, increasing the standard volume by over 100%. This design modification has optimized wells with very high free gas volumes (>88%), where the use of pumps with optimal designs and highly efficient gas separation systems has been required.

4. Isolation Method - Cup Packer: The seal created by the packer ensures the proper functioning of the equipment by preventing direct flow of free gas towards the pump. In wells with a tortuous trajectory (high DLS), excessive wear on the cups can occur. To prevent these damages before reaching the installation depth, a higher resistance elastomer with internal metal structure was included in the design. Additionally, in special cases, swellable materials are used to guarantee the seal even in the most challenging applications.

5. Metallurgy: To extend the tool's lifespan and ensure its reuse in case of reinstallation, two approaches have been used: one is adapting capillary tubing through the packing without causing damage to the cup that compromises effective sealing, thereby extending chemical treatment throughout the entire BHA. The second option is the use of coated parts with stainless steel components to guarantee a long lifespan and reuse if required.

CASE STUDIES

Case Study 1: Adapting for Dynamic Flow Conditions at the Delaware Basin

During the artificial lift planning process for a set of new wells intended to produce from the Bone Spring formation, and after reviewing all available information such as production type curves, fluid properties, and depletion behavior of offset wells, an operator determined that employing an Electrical Submersible Pump (ESP) represented the most viable solution to maximize the wells' profitability for their initial 6-12 months of production, before transitioning to its end-of-life artificial lift method.

The first ESP (Figure 8 – ESP Run #1), utilizing a 4000 bfpd series pump equipped with two Vortex Gas Separators and two motors in tandem, was installed on 11/4/2021. The ESP operated smoothly for three months until changes in flow conditions led to severe slugging events in the well, resulting in:

- The ESP system experienced gas lock and shutting down on multiple occasions.
- Flow occurring through the casing of the well.
- Considerable proppant flowback due to destabilization of the proppant pack caused by dynamic pressure changes and fluid conditions.

Excessive shutdowns caused by gas locking events reduced the daily production of the well to a third of its previous stable production, ultimately leading to mechanical failure of the ESP after 111 days due to solids (proppant) accumulation inside the pump. Driven by oil prices and well economics, the operator compared ESP versus Gas Lift systems' depletion capabilities and opted to install a second ESP system in the well.

The second ESP (Figure 8 – ESP Run #2) was installed on 3/10/2022. This time, a 1750 bfpd series pump equipped with two Vortex Gas Separators, a Gas Handler, two motors in tandem, and a gas regulator below the ESP system was installed to:

- Control the amount of free gas entering the ESP intake.
- Enhance the gas handling capabilities of the ESP system.
- Reduce proppant flowback by stabilizing flow conditions.
- Mitigate gas locking events and associated shutdown cycles.
- Restore production to its previous baseline.

With this second ESP run, overall stable production was achieved and sustained for 140 days until all the mud joints installed on the well became filled, starving the ESP system with solids once again. This led to a second mechanical failure related to solids production. During this ESP run, runtime increased by 27% compared to the previous run, and well production was re-established.

A third ESP (Figure 8 – ESP Run #3) was installed on 8/18/22. This time, an extended flow range 1750 bfpd series pump equipped with two Vortex Separator, a Gas Handler, a single motor, and a Vortex Regulator with a modified intake section equipped with a sand screen was installed with the following objectives:

- Utilize the advanced gas handling capabilities of the extended range series pumps and adjust for new well conditions as higher amounts of free gas were expected.
- Reduce overall shaft loading by 20% due to the number of pumps, separators, and motors running in the hole.
- Control and reduce the number of solids entering the system to increase mud joints filling time.

- Maintain the production baseline achieved in the previous run by regulating the free gas before the pump intake.

This third ESP failed after 340 days from its installation, on 7/24/23, resulting in a 143% improvement from the previous run and a 206% improvement compared to the first ESP installation. The third run achieved record-low bottomhole flowing pressures of 392 psi and maintained well production levels along with its associated depletion profile.

Case Study 2: Continuous Improvement in Delaware Basin
Shortly after implementing the first ESP Vortex Regulator in the area, and with a better understanding of the dynamic flow conditions, a new field test was conducted. Two new wells were completed in the same formation using ESPs with extended flow range 3500 bfpd series pumps, along with associated gas handling elements such as gas handlers, gas separators, and gas regulators at the bottom. The first well failed 275 days after installation due to an operational issue unrelated to the flow dynamics of the formation. The second well (Figure 9) failed after 564 days of installation. This second ESP could produce the well from 2300 bfpd to 350 bfpd, with Gas Liquid Ratio (GLR) ranging from 180 – 1,900 scf/stb, depleting the well to record-low Pump Intake Pressures (PIP) of 498 psig. Both wells were converted to their end-of-life artificial lift systems afterward.

Case Study 3: One last ESP Run! – Efficiently producing ESPs below 400 bfpd in the Midland Basin.

Operators in the Midland Basin often find themselves in a challenging situation when transitioning from an initial artificial lift system to its end-of-life counterpart.

The decision should be straightforward, with economics guiding the choice. However, even after conducting a quantitative economic analysis, Production Engineers face several ever-changing factors beyond their control. Commodity prices, contractual production agreements, reservoir heterogeneity, detrimental effects of well interference, and offset well frac hits are common variables that can favor one artificial lift system over another at different times.

In the example illustrated below (Figure 10: ESP run 2&3), the decision was made to install a final ESP in a Middle Spraberry well after the current ESP system failed due to tubing damage. By this point, the well's total fluid production had fallen below 400 bfpd, with a GLR of 900 scf/stb and a rising trend. Analysis indicated approximately 35% free gas at the pump intake based on 24-hour well test data, with signs of consistent moderate to severe gas locking events according to ESP downhole sensor data trends.

A downsized ESP was installed, featuring a 750 bfpd series extended flow range pump supplemented by a 1750 bfpd series pump serving as a charge pump, gas handler, gas separator, and Vortex Regulator. This new configuration effectively managed the well's production without overheating or shutdowns due to gas locking. It successfully operated with fluid production down to 350 bfpd and adapted to handle increased gas influx (GLR of 1200 scf/stb) as more gas emerged before the ESP was removed due to tubing damage.

Following this failure, another ESP was installed with adjustments to pump sizing to accommodate the increased gas volume observed. Figure 11 zooms into the period between this last ESP run (ESP Run #2&3) and its previous installation (ESP Run #1). A deeper analysis of the ESP system's operation reveals that the gas regulator helps reduce the severity and magnitude of gas slugs that might otherwise overwhelm the ESP intake and exceed its gas handling capabilities. In this case, employing the gas regulator minimized electrical stress on the ESP system, as evidenced by reduced motor current swings.

Case Study 4: Slug Flow on High GLR Formations.
ESPs, depending on stage geometry, provide a certain amount of lift per stage, defined as head. As the wells deplete and more free gas emerges, additional gas enters the ESP pump intake, leading to head degradation. In some instances, head degradation can severely impact ESP systems, causing them to experience issues such as gas locking, loss of head, overheating, and shutdown. Additionally, under certain control algorithms, which adjust operating parameters (typically ESP frequency) based on measured inputs (usually motor or drive current), the ESP may oscillate around a specific PIP floor.

This latter effect has recently been identified and is currently under analysis in the field. Figure 12 illustrates a well completed in Wolfcamp A initially equipped with an ESP featuring an extended flow range 4000 bfpd series pump, which failed due to tubing damage. Before the failure, the well's PIP reached approximately 1,100 psig, a low limit that could not be surpassed.
Subsequently, a decision was made to employ a downsized tapered ESP design, utilizing a 1750 extended flow range pump series, with a 3500 bfpd extended flow range series pump serving as a charge pump, gas handler, gas separator, and Vortex Regulator below the ESP. Shortly after implementation, the low PIP limit of 1,100 psig was surpassed, and the well is currently producing at a PIP of 920 psig, effectively managing the increasing gas volume released naturally as the well depletes.

Figure 13 zooms into the period between the last ESP run (ESP Run #2&3) and its preceding installation (ESP Run #1). Upon closer examination of the ESP system's operation, we can discern that employing the Vortex Regulator aids in mitigating the severity and magnitude of gas slugs that might otherwise pass directly through the ESP intake, occasionally surpassing the ESP's technical capabilities for gas handling. In this instance, the utilization of the Vortex Regulator minimizes electrical stress on the ESP system, as evidenced by the reduction in motor current swings.

CONCLUSIONS

- There are several factors affecting the gas bubble sizes and through the understanding of these factors, improvement can be made to the production strategy and downhole equipment in order to reduce the gas bubble size and disperse gas slugs into the liquid phase.

- The fundamental function of the Vortex Regulator is dispersing the gas bubble into the liquid phase, preventing excessive free gas flowing around the motor. This purpose is achieved by conditioning the production fluid, changing the flow regime from slug to dispersed bubble.

- Multiple applications have proven the effectiveness of the tool performance and have allowed the assessment of the challenges increasing the understanding of its operations in different downhole conditions and improve the existing design mitigating these challenges to increase the chances of succeed in every application.

- Considering a multi-faceted approach that combines the proper design of the Vortex Regulator with the ESP will yield the best achievable results. The proper overall design starts with a correct pump sizing.

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TABLES AND FIGURES

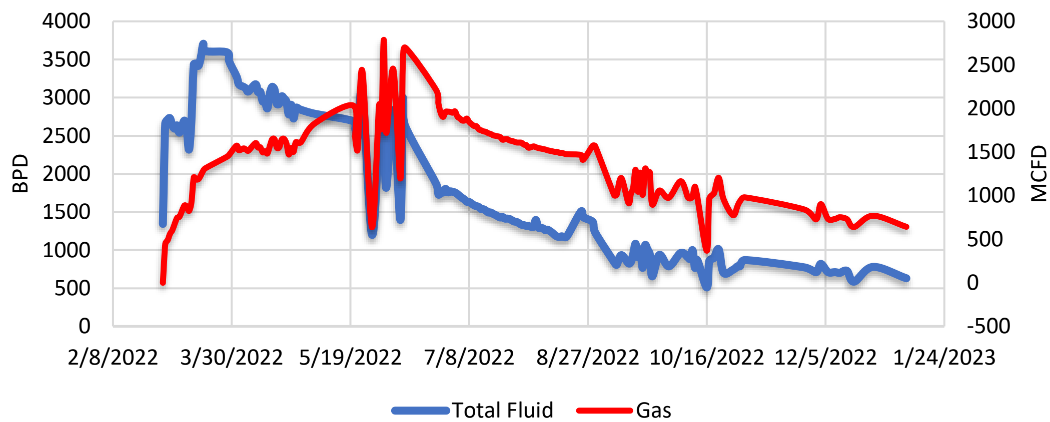


Figure 1 Rapid fluid declination-Unconventional reservoir.

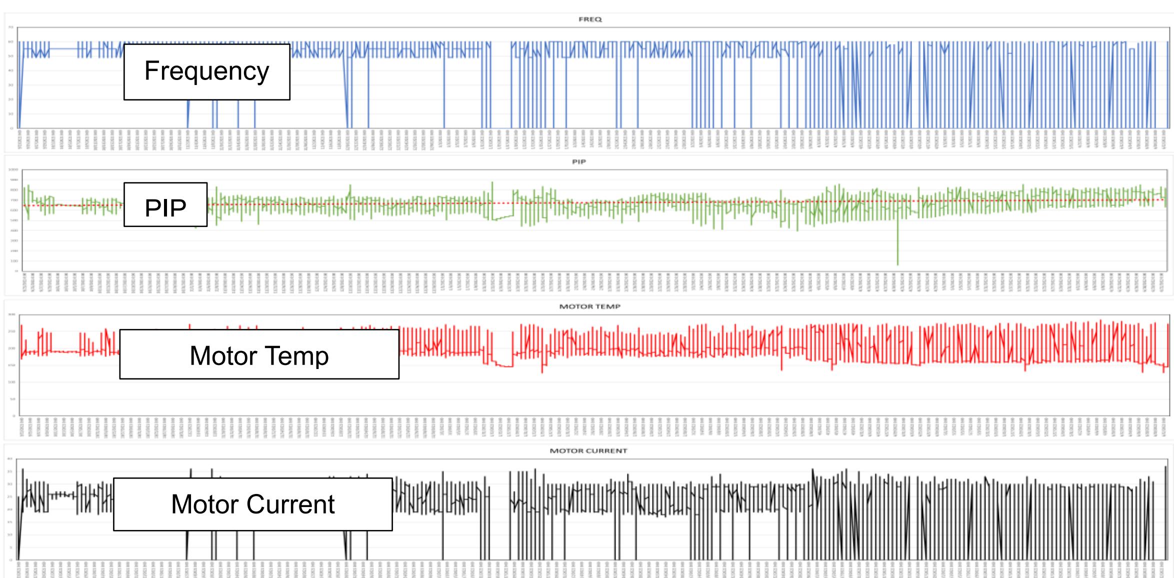


Figure 2 Pump performance under frequent shutdowns

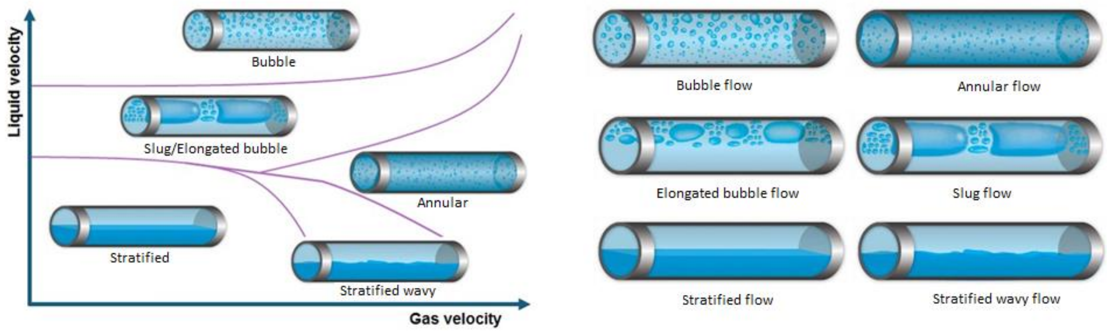


Figure *3* Flow Regimes-Horizontal pipe

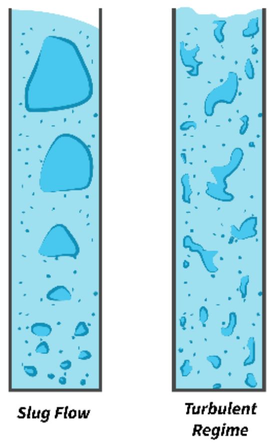
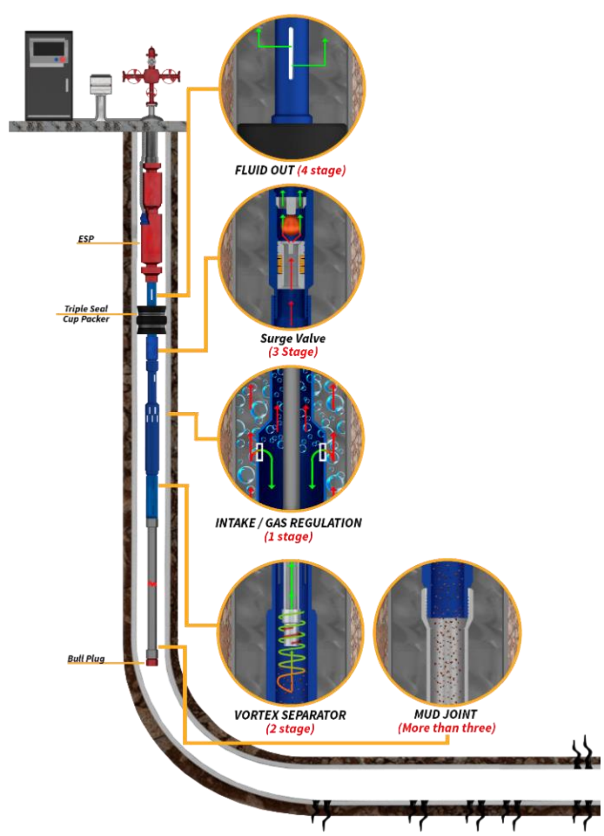


Figure 4 Effect of the turbulence in a multiphase system



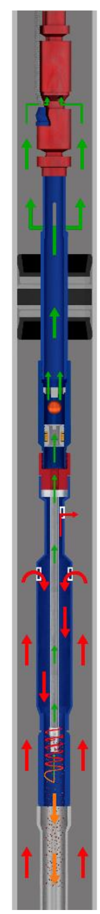


Figure 5 ESP Vortex Regulator Sketch and Flow Path

Figure 6 Sand accumulation inside the tool

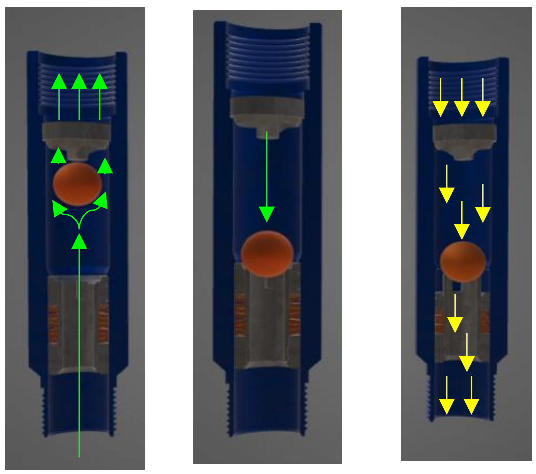
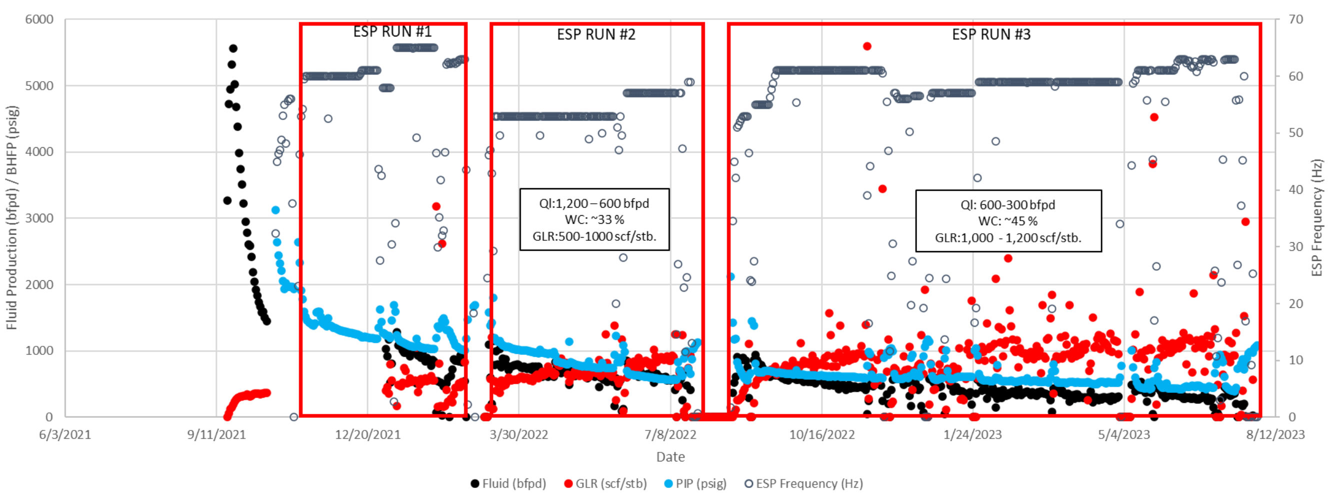
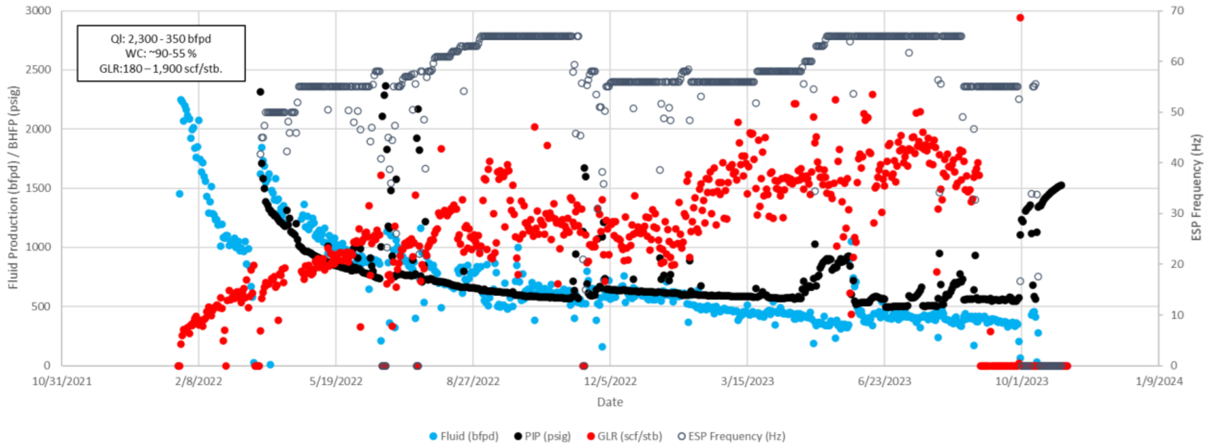


Figure 7 Surge Valve Operation



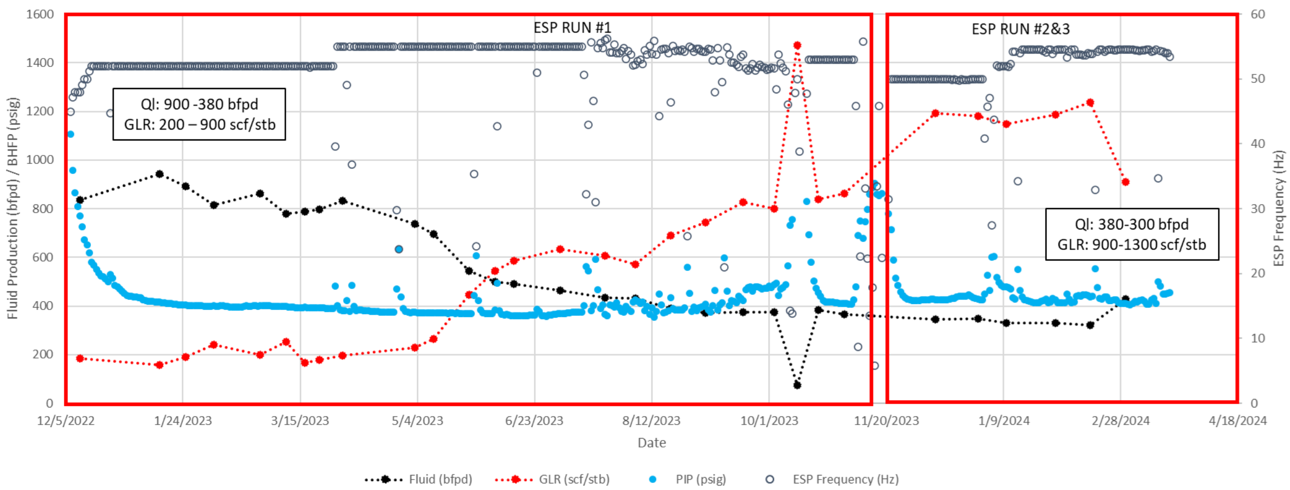
Install	Pull	Runtime (days)	Improvement vs 1st run	Failure Notes	Main Pump	Gas Handler	Gas Separator	Motor	Vortex Regulator	Lowest PIP
11/4/2021	2/23/2022	111		Broken Shaft / Solids	4300H - 243 STG	NA	2 VTX	348 HP / 2833 V / 78.5A	NO	1,003
3/10/2022	7/29/2022	141	27%	Broken Shaft / Solids	1750H - 400 STG	YES	2 VTX	288 HP / 2348 V / 78.5 A	YES	562
8/18/2022	7/24/2023	340	206%	GDH / Solids	17.5H - 372 STG	YES	1- 2S VTX	204HP/ 2695V / 48.5 A	YES	392

Figure 8 Bone Spring Formation Case Study No. 1



Install	Pull	Runtime (days)	Failure Notes	Main Pump	Gas Handler	Gas Separator	Motor	Vortex Regulator	Lowest PIP
3/25/2022	10/10/2023	564	Low/No Flow - ALS Conversion	35H - 253 STG	YES	1 - 2STG VTX	336 HP / 3270 V / 65 A	YES	498

Figure 9 Bone Spring Formation Case Study No.2



Install	Pull	Runtime (days)	Failure Notes	Main Pump	Charge	Gas Handler	Gas Separator	Motor	Vortex Regulator	Lowest PIP
12/6/2022	10/16/2023	314	HIT	17.5H -372 STG	NA	NA	2 VTX	204HP/ 2695V / 48.5A	NO	350
10/17/2023	11/20/2023	34	HIT	7.5H - 250 STG	17.5H - 90 STG	UNB GAS	2 VTX	204HP/ 2695V / 48.5A	YES	407
11/21/2023	3/20/2024	120		17.5H -372 STG	NA	UNB GAS	2 VTX	204HP/ 2695V / 48.5A	YES	405

Figure 10. Low Flow ESP. Middle Spraberry Case Study

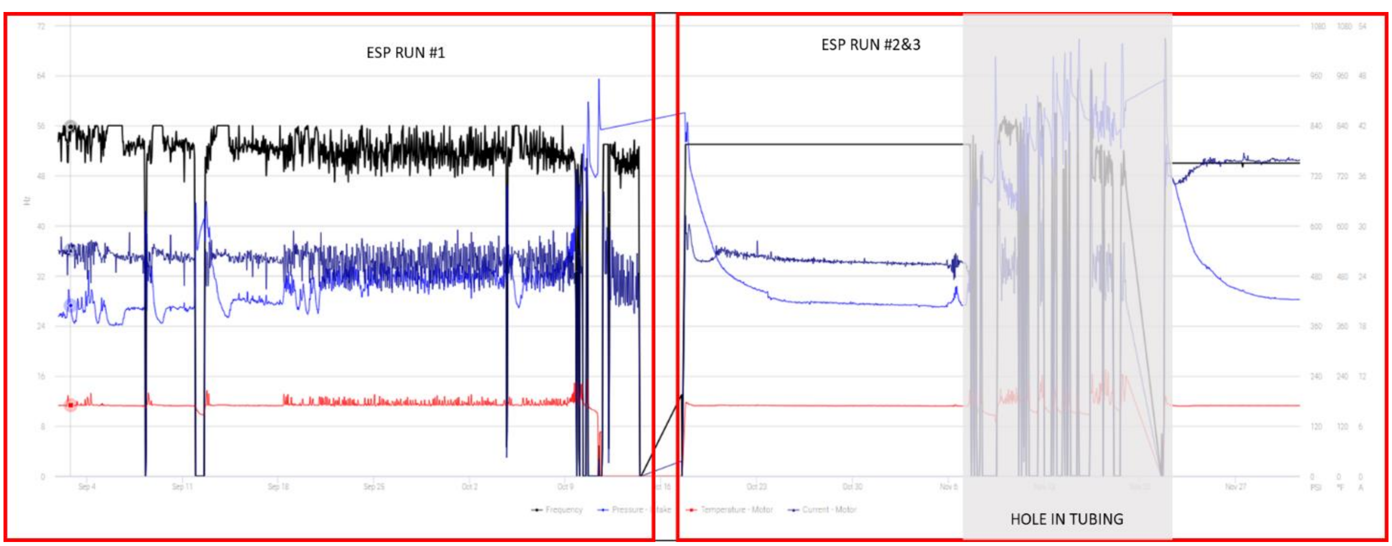
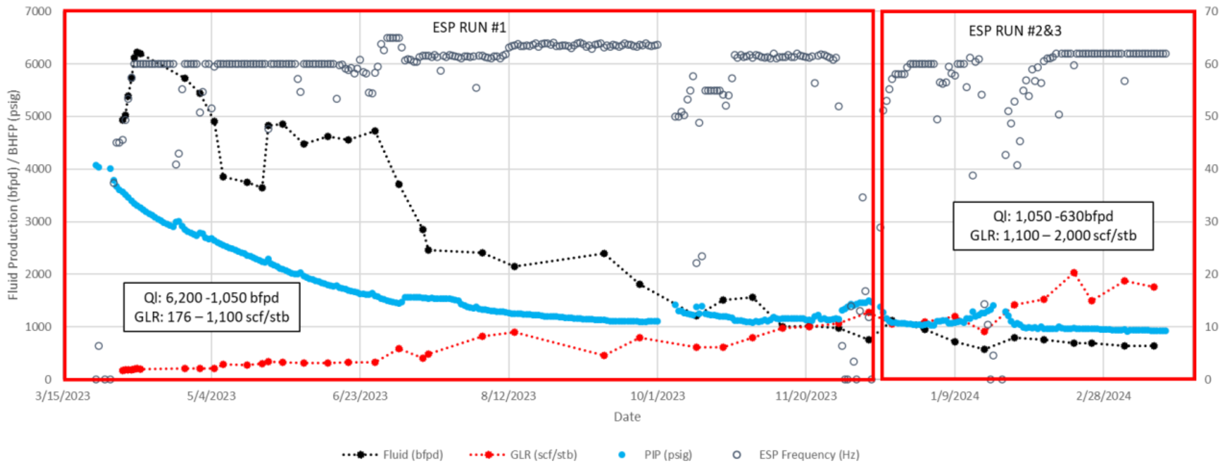


Figure 11 depicts the behavior of PIP and motor current (A) with and without the use of the Vortex Regulator in a low-flow Middle Spraberry well.



Install	Pull	Runtime (days)	Failure Notes	Main Pump	Charge	Gas Handler	Gas Separator	Motor	Vortex Regulator	Lowest PIP
3/23/2023	12/13/2023	265	HIT	43H - 292 STG	NA	NA	2 VTX	382HP / 3360 V / 73A	NO	1,100
12/14/2023	1/25/2024	42	HIT	17.5H -372 STG	35H - 93 STG	UNB GAS	2 VTX	347 HP / 3060 V / 73 A	YES	1,040
1/26/2024	3/20/2024	54		17.5H -372 STG	35H - 93 STG	UNB GAS	2 VTX	347 HP / 3060 V / 73 A	YES	920

Figure 12. Breaking through low PIP barriers Wolfcamp A

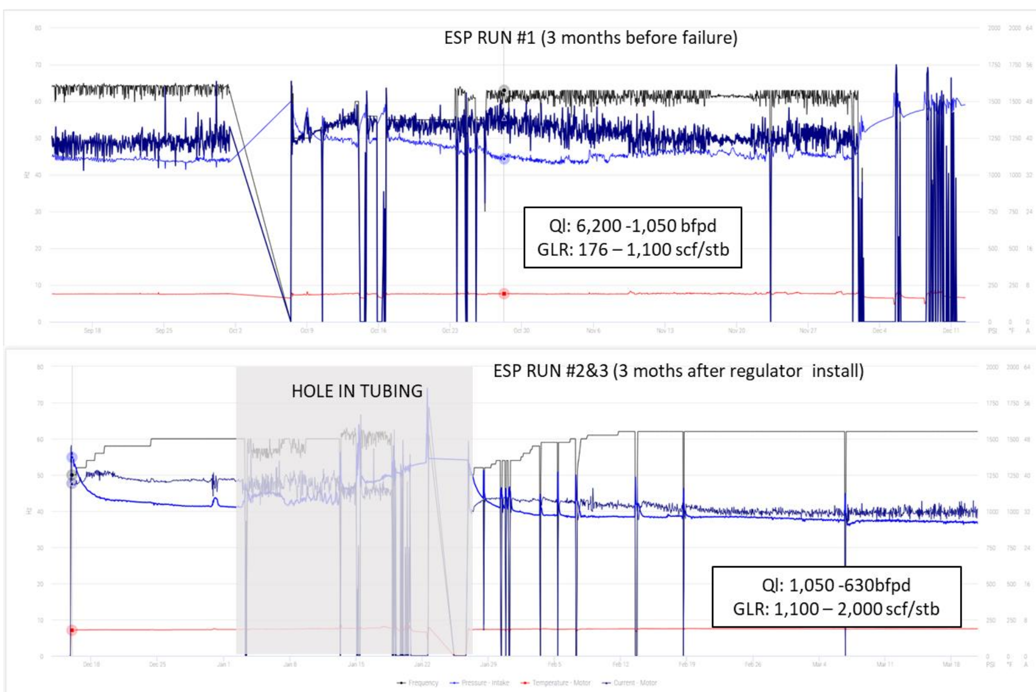


Figure 13. High GLR - Slug Formation - ESP Vortex Regulator Application Wolfcamp A