OPTIMIZING ESPS: GAS AND SAND FLOW MANAGEMENT FOR ENHANCED UPLIFT

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ABSTRACT

This paper introduces a multi-layered application to tackle two major challenges in unconventional wells within the Permian Basin: gas slugs that disrupt electric submersible pump (ESP) operations, and sand fallback during ESP shutdowns, which can cause equipment failures like plugged pumps and broken shafts. These issues reduce efficiency, increase downtime, and drive-up operational costs.

The solution features a gas handler system that regulates free gas flow before it reaches the ESP intake, converting slug flow into dispersed bubble flow. It also incorporates a sand fallback management system, installed above the ESP discharge, which prevents sand settling in the pump stages during shutdowns caused by different factors. The system supports surface injection rates of more than 8 barrels per minute, enables detailed inspection and repair post-retrieval, and accommodates flow rates up to 15,000 BPD with sand concentrations as high as 23,000 mg/L.

Four case studies from the Delaware Basin, where ESP operations were historically hindered by gas and sand, demonstrate the system's effectiveness. Following the installation of the gas flow management tool below the ESP and the sand fallback regulation tool above it, production increased significantly, and operational stability improved. By extending ESP runtime and minimizing premature failures, the solution enhances profitability and reduces the carbon footprint of operations.

FIELD BACKGROUND AND CHALLENGES

Located in the Delaware Basin, this reservoir is currently being developed by Apache and consists of multiple wells utilizing ESPs, to enhance oil production. However, in recent years, the field has faced challenges related to gas and ESP performance. As a result, many wells have experienced depletion, with production rates declining to below 1000 barrels of fluid per day.

GAS SLUGS: PROBLEM

The decline in bottomhole pressure due to fluid production alters flow regimes within the casing. In conventional reservoirs, these changes occur gradually; however, in the past decade, it has been observed that unconventional reservoirs experience much faster transitions due to a more rapid bottomhole pressure decline. These swift changes can take place in less than a year and impact the performance of artificial lift systems.

During the early production stages, free gas production rates are typically low and do not significantly affect Electric Submersible Pumping (ESP) systems. However, as bottomhole pressure declines rapidly, the volume of free gas at the wellbore increases, eventually leading to gas slugs—continuous phases of gas flow (Figure 1).

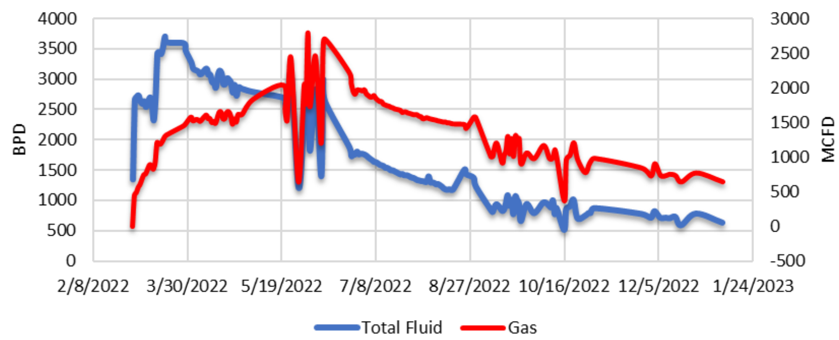

Figure 1 Accelerated fluid depletion in unconventional reservoirs.

The presence of gas bubbles in the liquid phase influences liquid production in different ways, with the severity depending on bubble size and the type of pumping system used. In ESP systems, significant amounts of free gas can severely impact performance. Gas bubbles reduce heat transfer from the motor to the surrounding fluid, causing excessive overheating, frequent shutdowns, shorter run times, and overall lower liquid production (Figure 2). Repeated shutdowns and restarts not only decrease equipment lifespan but also increase the risk of premature failures, necessitating workover interventions and raising operational costs.

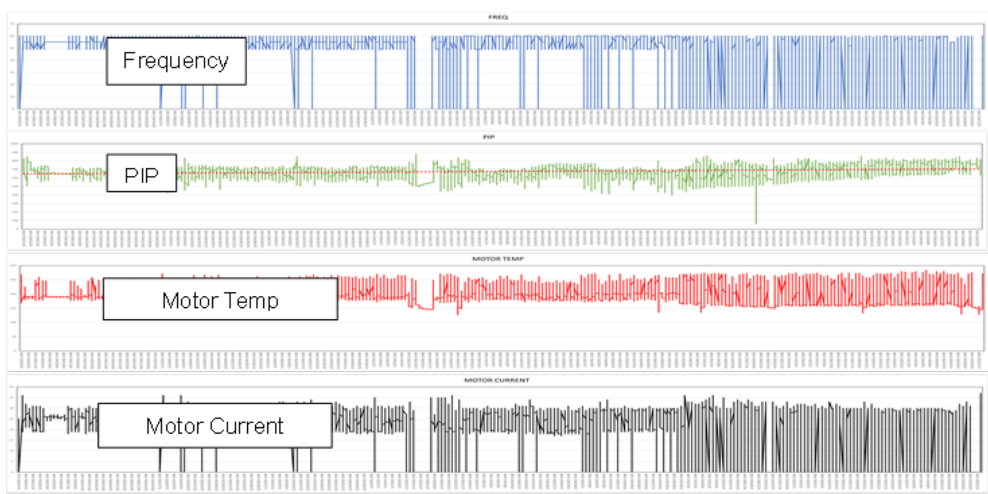

Figure 2 Impact of recurrent shutdowns on pump performance.

Utilization of a Gas Regulation system for ESPs

The abovementioned advancements have one thing in common which is the utilization of a shroud to encapsulate part of the ESP system. Utilization of shrouds involves downsizing of ESP motors which limits HP that certain wells cannot afford. This innovation to handle gas on ESP wells is designed to regulate gas rather than separating it which in turn allows operators to use their desired ESP design with no limitation. It connects below the sensor and has 4 main gas regulation sections that condition the fluid before it flows around the motor.

The system comprises of 4 key sections:

1. **Triple Seal Packer**: The packer directs fluid from the perforations into the pressurization chamber. It features three elements: two oppositely facing cups and a central elastomer cylinder as shown

in Figure 3. The cups utilize bottom-hole and hydrostatic pressure to compress the elastomer, creating an effective seal to prevent gas leakage.

2. **Pressurization Chamber:** This Chamber comprises of an oversized body as shown in Figure 11. (left) that has engineered slots with precise dimensions cut into it that is the intake to the ESP. The oversized body can have an ID of 3”, 3.5”, 4” based on design selected.
3. **Centrifugal Regulator:** The regulator is made of precise vanes cut at an angle for fluid flow that induces a centrifugal force as shown in Figure 3.
4. **Surge valve:** The surge valve is made of 2 valves that control the surge using a silicon carbide ball and bevel springs as shown in Figure 3 that allow back flush through the triple seal packer when needed.

Figure 3 Gas Handler Components

The regulation processes its thanks to the Triple Seal packer that allows Gas Slugs to mix with the fluid that it carries thus acting as the 1st stage of the gas regulation process where the slugs are broken down into smaller gas bubbles. The gas bubbles along with the liquid then enter the pressurization chamber where the fluid velocity is decreased using the oversized chamber which in turn increases pressure using the Bernoulli’s principle that allows smaller gas bubbles to get entrained back in the solution. The Centrifugal regulator is the 3rd stage where the centrifugal force induced, further breaks gas bubbles into dispersed bubble flow before it enters the dip tube that is connected to the surge valve. The surge valve controls the surge by adding time when hydrostatic pressure increases more than the bottom hole pressure which allows slugs to mix with liquid. These 4 stages of mixing finally let homogenous flow exit out above the packer thus allowing effective motor cooling as shown in Figure 4., which further prevents high motor temp shutdowns on ESPs.

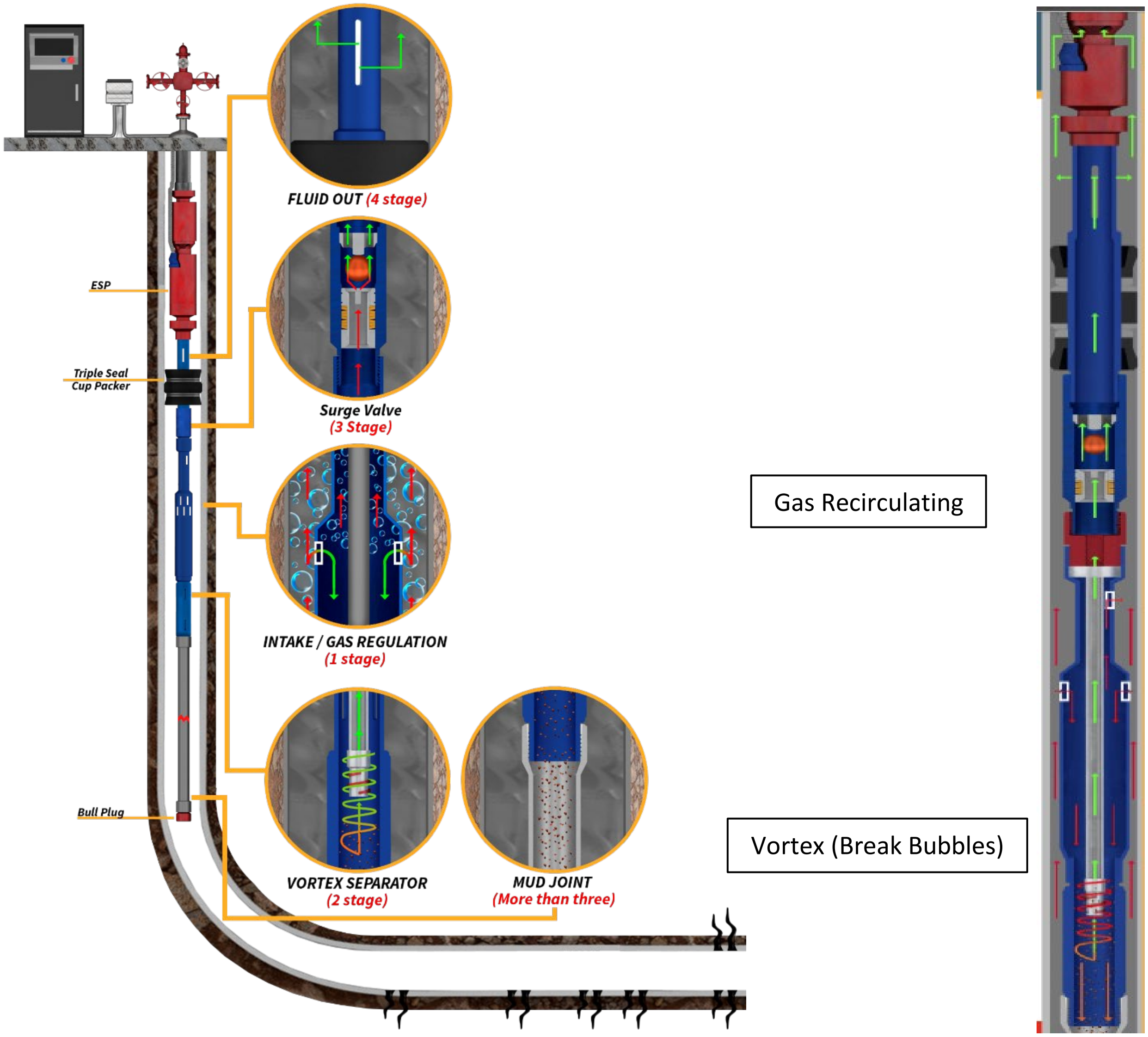

Figure 4 Wellbore Schematic (Left) and Flow Path (Right) through Gas Regulator

Design considerations: The presence of sand in production fluid is a common challenge. Addressing this issue without considering the flow of solid particles can result in complications, making it essential to account for sand production when designing the system. For wells with a high Gas-Liquid Ratio (GLR) exceeding 1,800 SCF/STB, an increased liquid volume within the tool is necessary to achieve effective mixing. To address this, the liquid pool chamber length was extended from 20 feet to 44 feet, more than doubling the standard volume. This design adjustment has proven effective in optimizing wells with high free gas content (>88%), requiring pumps with advanced designs and highly efficient gas separation systems. To enhance the tool's durability and enable reuse during reinstallation, stainless steel components with protective coatings are incorporated, ensuring a longer operational lifespan.

Utilization of a Hybrid ESP Sand Flowback Device

A hybrid device has been designed to control sand flowback by combining the best features of existing tools while addressing their limitations (Figure 5). This device features an extended and wider body (24 ft in the 350, 400, and 450 series), enhancing sand retention capacity. It also includes a longer internal screen with a patented inverted top roof design that redirects flow and prevents sand from entering the screen, keeping it contained within the device.

The internal screen remains clear of sand, with an open flow area aligned with the pump discharge, allowing gas to flow from the pump through the tool and into the tubing. This design also facilitates the injection of pump fluids (such as fresh water or chemical treatments) through tubing into the ESP pump, ensuring smooth restarts. Additionally, solids jet port fittings enable complete self-cleaning of the tool after restart.

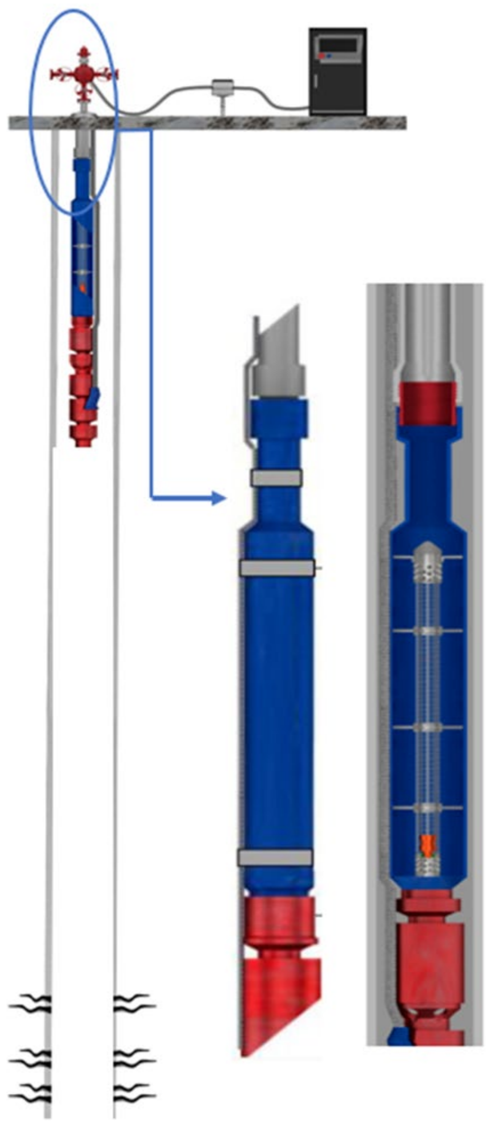

Figure 5 ESP SAND LIFT

Threaded adapters allow for easy disassembly, inspection, and refurbishment. In summary, this device:

- Enables pumping through the tubing (Figure 6).
- Protect pumps from sand flowback while keeping the discharge path clear for gas to escape through the tool and up the tubing.
- Ensure smooth and reliable restarts.

- It is fully refurbishable and reusable, requiring only minor component replacements due to the high-quality materials used.

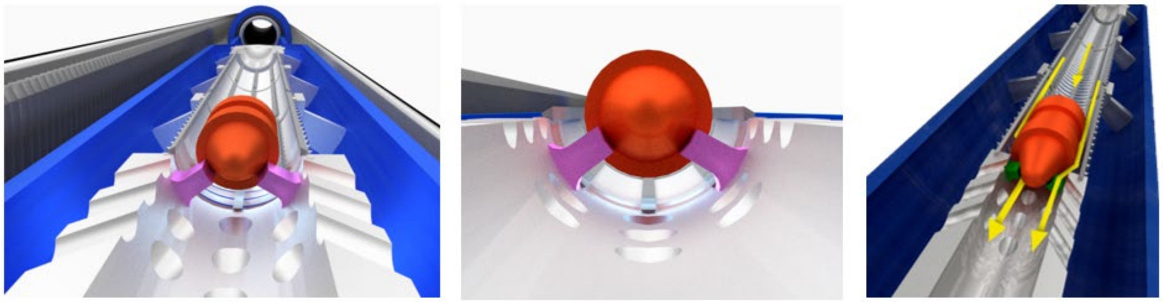

Figure 6 Open flow area aligned to the pump discharge.

During pump restart, the Sand Lift utilizes pump discharge pressure to expel fluid and solids from its chamber. The lower ports are designed as jet ports, effectively sweeping and breaking up surrounding solids. Computer simulations indicate that fluid velocity in these jet ports can reach up to 132 in/s. However, this effect depends on the pump achieving sufficient discharge pressure. If solids accumulate in the lower pumps and prevent adequate pressure buildup, the jetting mechanism will not activate. This highlights the necessity of using combined sand control systems both above and below the pump.

Once the system resets, fluid flows through the inner string, passes through the inverted mesh into the tool body, and then moves into the tubing. The inner string contains a dart that moves up and down depending on operational conditions. During pump restart, the dart clears the flow area inside the inner string, preventing sand accumulation in the mesh. After restarting, the dart moves upward, opening the flow path below it and settling at the top of the inner string in a designated "dart garage." The full operational sequence is depicted in Figure 7.

This tool's design allows production engineers to analyze its internal components after removal from the well, providing valuable data on solid types, volume, and the severity of downhole issues. All Sand Lift components are inspectable and replaceable without cutting the tool, facilitating easy inspection and reconditioning. This feature reduces costs by minimizing the need for new equipment purchases.

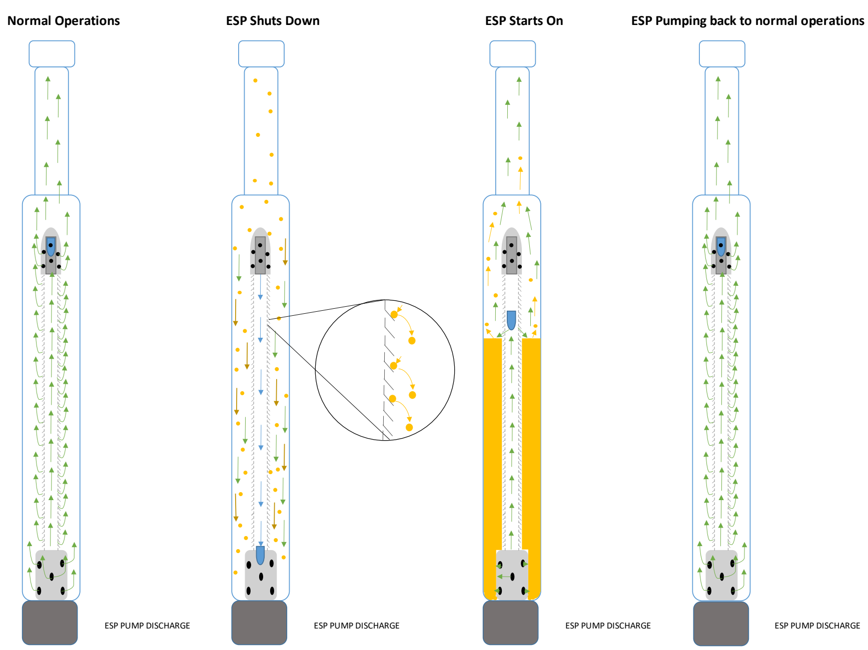

Figure 7 Sand Lift Operation

CASE OF STUDIES

Case Study 1

This case focuses on a well in the Permian Basin equipped with an electrical submersible pump (ESP). Before implementing gas separation and sand control technologies, an analysis was conducted using the data outlined in Table 1.

WELL CONDITIONS	
ALS:	ESP
CASING OD/WEIGHT:	5-1/2" - 20.00 lb/ft
CASING ID:	4.778 in
TUBING:	2-7/8" in
TOP OF LINER:	N/A
FLUID PRODUCTION:	925 BFPD
WATER CUT:	80.54 %
OIL FLOW:	180 BOPD
WATER FLOW:	745 BWPD
GAS FLOW:	440 MCFD
GOR:	2444.444 SCF/STB
GLR:	475.676 SCF/STB
Sensor Depth	N/A

Table 1 Well Data

Figure 8 shows the production of gas, oil, total allocated fluid, and water over time, with a notable change occurring in September 2024, when a gas separator and a sand control tool were installed. Before the installation, gas production fluctuated around 1,000 MCFD, while oil production remained relatively stable at approximately 200-300 BOPD. The total allocated fluid production hovered near the expected value of 925 BFPD. After the separator installation, gas production appears to have stabilized with fewer fluctuations, while oil production shows a slight upward trend. The total fluid production remains close to the expected 925 BFPD, indicating the separator's effectiveness in optimizing phase separation and good solids control.

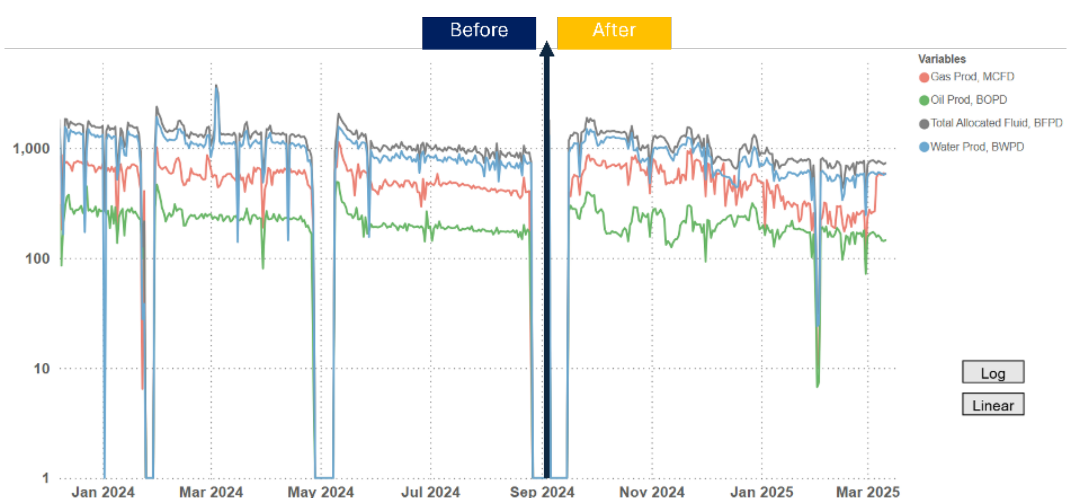

Figure 8 Daily Production Case Study 1

Figure 9 shows the frequency data of various parameters related to the system's performance over time, with significant changes noted after the installation of a gas separator and a sand control system in September. The average frequency appears steady at approximately 50 Hz, with noticeable fluctuations in August and September after installation it remained between 50 Hz and 55 Hz with some fluctuations. The motor temperature stabilizes around 180°F in both cases, showing a decline after the separator installation. The intake temperature maintains a steady range of 160°F in both cases, while the motor current averages approximately 37A, after the installation it remained between 45 A and 40 A with some fluctuations. Pressure in the tubing remains consistently low, around 5-10 PSI in both cases, and the casing pressure averages close to 2-5 PSI in both cases. The addition of the gas separator in September seems to have significantly impacted these parameters, contributing to smoother operation and reduced fluctuation in key metrics.

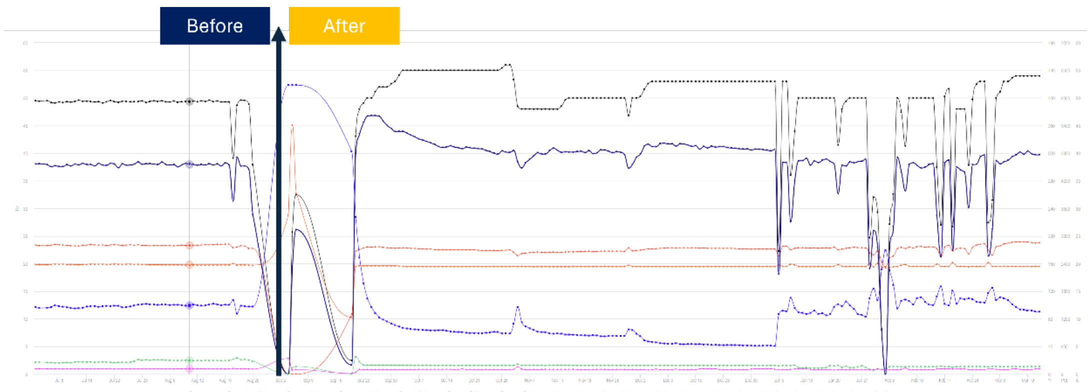

Figure 9 Sensor Readings Case Study 1

Case Study 2

This case focuses on a well in the Permian Basin equipped with an electrical submersible pump (ESP). Before implementing gas separation and sand control technologies

Figure 10 shows distinct trends before and after the installation of the gas separator in October 2024. From January to September 2024, the gas production averaged around 900 MCFD, oil production was consistent at approximately 300 BOPD, total allocated fluid maintained an average of 1,400 BFPD, and water production averaged about 1,100 BWPD. After the installation of the gas separator, from November 2024 to March 2025, gas production increased by approximately 10–15%, reaching an average of 1,100 MCFD. Oil production remained stable at 300-400 BOPD, while total allocated fluid and water production averages were largely unchanged, maintaining levels of around 1,450 BFPD and 1,100 BWPD, respectively. This indicates that the installation of the gas separator successfully enhanced gas extraction efficiency without negatively impacting other production parameters.

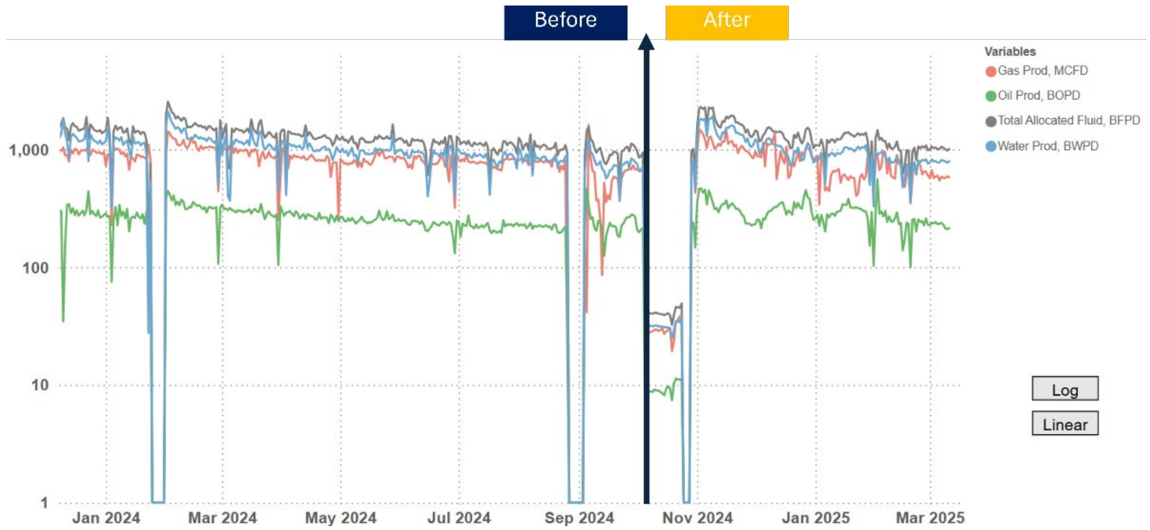

Figure 10 Daily Production Case Study 2

Figure 11 shows the sensor reading graph that displays various system parameters over time, with a notable change occurring after the installation of a gas separator at the end of October. Prior to the installation, the frequency fluctuated around an average of 42-45 Hz. Post-installation, the frequency stabilized closer to 50 Hz, indicating improved operational consistency. The motor temperature averaged lower than 45°F before the installation and increased to approximately 190°F. Pressure tubing and pressure casing both demonstrated marginal activity before the installation, but post-installation showed a more defined pattern: pressure tubing peaked around 1.2 psi, and pressure casing averaged approximately 2.5 psi, indicating improved fluid dynamics due to the gas separator. Overall, the installation of the sand control and the gas separation tools appears to have positively impacted system stability, efficiency, and performance consistency across all sensor readings.

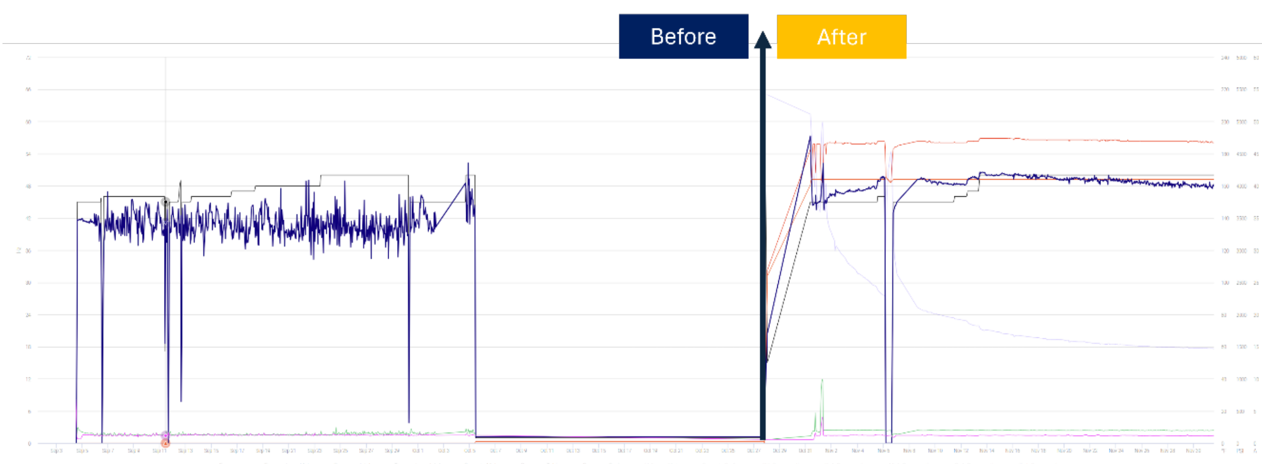

Figure 11 Sensor Readings Case Study 2 After Installation

Case Study 3

This case focuses on a well in the Permian Basin equipped with an electrical submersible pump (ESP). Before implementing gas separation and sand control technologies, an analysis was conducted using the data outlined in Table 2.

WELL CONDITIONS	
ALS:	ESP
CASING OD/WEIGHT:	5-1/2" - 23.00 lb/ft
CASING ID:	4.670 in
TOP OF LINER:	N/A
FLUID PRODUCTION:	775 BFPD
WATER CUT:	61.93 %
OIL FLOW:	295.04 BOPD
WATER FLOW:	479.96 BWPD
GAS FLOW:	335 MCFD
GOR:	1135.439 SCF/STB
GLR:	432.258 SCF/STB
Sensor Depth	10587.50 FT MD

Table 2 Well Data

Figure 12 shows fluid production trends over time, highlighting the installation of a gas separator in September 2024. Before the installation, total fluid production fluctuated, with oil production (green) averaging around 1000 and 500 BOPD, water production (blue) averaging around 1400 and 800 BOPD, and gas production (red) varying around 1000 and 800 MCFD. Following the installation, production was expected to stabilize at approximately 775 BFPD, oil and water production remained constant and even increased compared to the expected production value, with production values higher than 1000 BFPD. Gas production appears to have stabilized and even decreased with gas values below 100 MCFD, suggesting improved efficiency. The graph reflects the impact of the separator on gas management while maintaining steady fluid production.

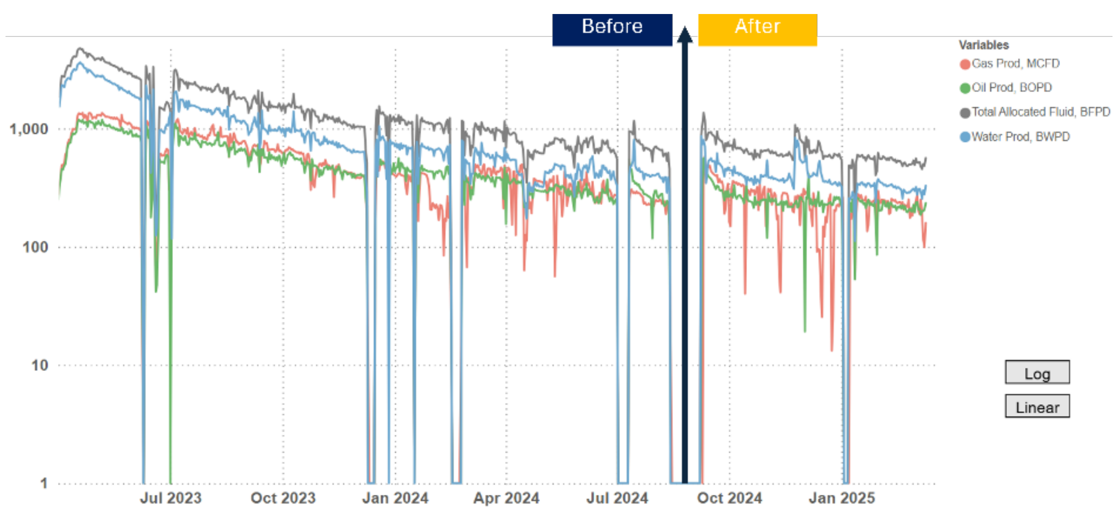

Figure 12 Daily Production Case Study 3

Figure 13 shows a sensor reading graph a noticeable change in system behavior following the installation of a gas separator and a sand control tool in September. Prior to this, the pump intake pressure averaged around 1.5–2 psi, with small fluctuations. After the installation, the pump intake became more stable, maintaining a lower but consistent average of 1–2 psi, likely due to improved gas handling efficiency. The motor frequency before September was somewhat irregular due to frequent system stops, averaging around 45–50 Hz, but post-installation, it remained consistently at 56 Hz, indicating a stable operation.

The motor temperature averaged around 200–210°F before the upgrade, after de installation it stabilized at a slightly lower average of 190–195°F. Similarly, the motor current showed erratic behavior before September, ranging from 20–60 amps and averaging about 35–40 amps. Post-installation, it stabilized within a narrower range of 45–45 amps, reflecting more efficient and balanced electrical performance. Overall, the data suggests that the new tools install significantly improved the system's stability and operating efficiency.

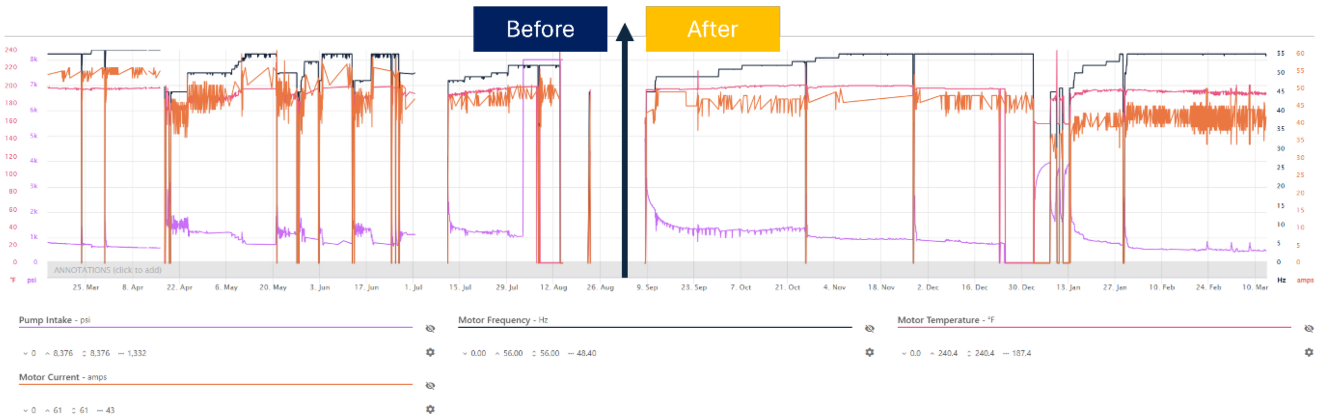

Figure 13 Sensor Readings Case Study 3

Case Study 4

This case focuses on a well in the Permian Basin equipped with an electrical submersible pump (ESP). Before implementing gas separation and sand control technologies, an analysis was conducted using the data outlined in Table 3.

WELL CONDITIONS	
ALS:	ESP
CASING OD/WEIGHT:	5-1/2" - 23.00 lb/ft
CASING ID:	4.670 in
TUBING:	2-7/8" in
TOP OF LINER:	N/A
FLUID PRODUCTION MAX:	592 BFPD
WATER CUT:	59.645 %
OIL FLOW:	238.9 BOPD
WATER FLOW:	353.1 BWPD
GAS FLOW:	189.7 MCFD
GOR:	794.056 SCF/STB
GLR:	320.439 SCF/STB
Sensor Depth	10,292.8 FT MD

Table 3 Well Data

Figure 14 shows fluid production trends over time, highlighting the installation of a gas separator and sand control tools in February 2024. Before the installation, total fluid production fluctuated, with oil production (green) averaging around 200 and 300 BOPD, water production (blue) slightly above 600 BWPD, and gas production (red) varying around 500 and 100 MCFD. Following the installation, production was expected to stabilize at approximately 592 BFPD, oil and water production remained constant and even increased compared to the pre-installation data and the expected production value, with production values close to 1000 BFPD. Gas production appears to have stabilized and even decreased with gas values below 100 MCFD, suggesting improved efficiency. The graph reflects the impact of the separator on gas management while maintaining steady fluid production.

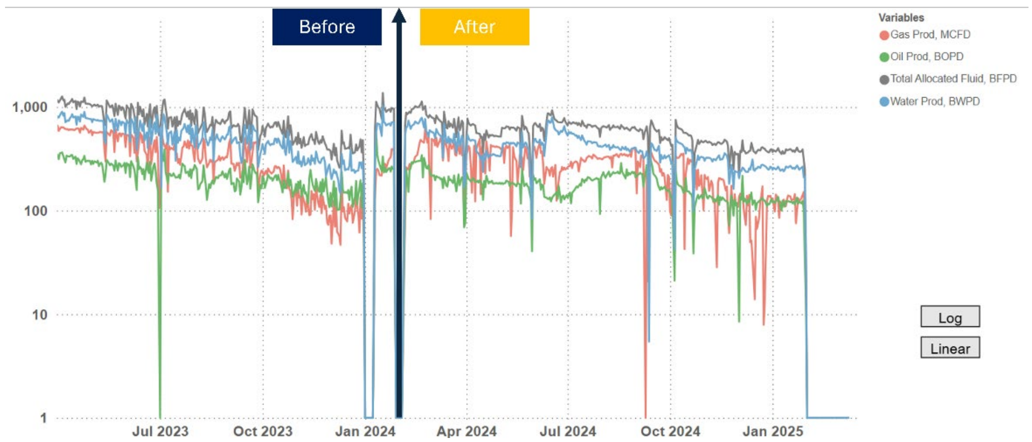

Figure 14 Daily Production Case Study 4

Figure 15 shows multiple parameters of the frequency inverter over time, with a notable event occurring in February involving the installation of new tools. Key average readings include the following: Frequency maintained an average around 60 Hz with occasional drops, indicating a stable operational range. The motor temperature remained consistent, averaging near 150°F, while temperature intake stayed around 120°F, showing reliable intake conditions. Motor current averages near 30 A, reflecting steady energy consumption, the installation of the gas separator appears to have contributed to enhanced stability and efficiency, particularly by reducing anomalies and fluctuations after February.

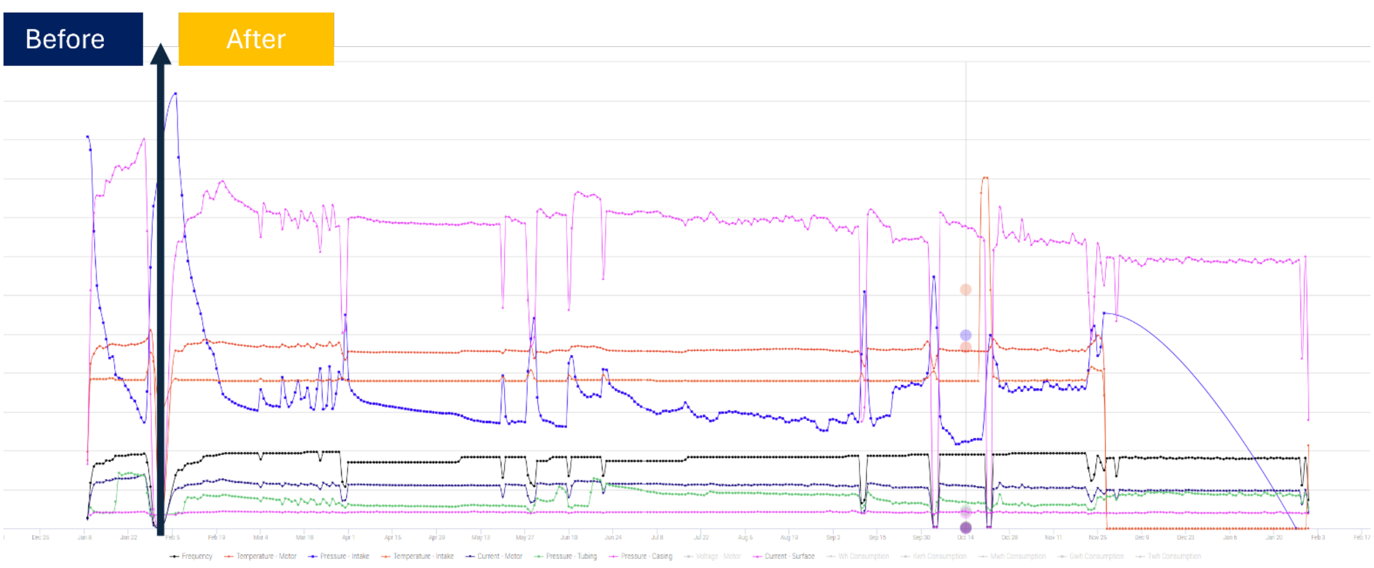

Figure 15 Sensor Readings Case Study 4

CONCLUSIONS

- Various factors influence gas bubble sizes, and by understanding these factors, production strategies and downhole equipment can be optimized to minimize bubble size and disperse gas slugs into the liquid phase.
- The primary role of the Vortex Regulator is to disperse gas bubbles into the liquid phase, preventing excessive free gas from circulating around the motor. This is accomplished by conditioning the production fluid and transitioning the flow regime from slug flow to a dispersed bubble state.
- Numerous applications have demonstrated the tool's effectiveness, enabling a better understanding of its performance across different downhole conditions. This has facilitated the refinement of its design to address operational challenges and enhance success rates in various applications.
- Adopting a comprehensive approach that integrates the proper design of the Vortex Regulator with the ESP will yield optimal results. Achieving an effective overall design begins with accurately sizing the pump.

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