MANAGEMENT OF GAS SLUGGING ALONG WITH SAND HANDLING TO IMPROVE ESP PERFORMANCE AND EFFICIENCY

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ABSTRACT

A dual purpose design is presented in this paper to face high gas presence and sand production conditions in petroleum wells with an Electric Submersible Pump (ESP) system installed. The results of this design's application in severely problematic wells, due to high gas and sand production, will confirm the importance of conditioning the fluid before it gets to the pump intake.

This engineered design consists of different stages from the isolation of the pump intake until the tubing bodies in charge of gas and sand handling. Engineering concepts were applied in the construction of this solution such as gas re-solubilization, changes of pressure and velocity, agitation, and vortex effect to finally present a design that is capable of breaking gas slugs into smaller gas bubbles that can be produced by the ESP system without impacting its performance, and at the same time separating fine solid particles (<250 microns) using centrifugal forces.

Case studies from wells located in the Permian basin will better explain the positive impact of selecting a proper downhole conditioning system to improve the ESP systems efficiency. A drastic improvement on the sensor parameters will also illustrate the effect of handling the gas and sand before the pump intake, which also leads to one of the most important consequences: A decrease in the number of shutdowns, which in turn decreases non-productive time, resulting in positive impact of fluid production. Additionally, the flexibility of this design is significant, since it allows it to be installed in a wide range of fluid production, gas-liquid ratio, tubing and casing sizes.

The novelty of this new design is the addition of the surge valve below the packer, which accomplishes multiple purposes: to avoid surging in the well, to allow testing the packer to assure it is properly set, and finally, allow chemical injection below the packer.

INTRODUCTION

The Wolfcamp shale has oil and gas formations extended along the Permian Basin and developed since the early 20th century with vertical wells, however, in the last two decades, the focus has changed looking for greater production through horizontal wells with greater production zones. These formations can be found in the Midland, Delaware, and Central basin platforms at different depths. According to information on the USGS2, just in the Midland basin, Wolfcamp contains around 20 billion barrels of oil, 16 trillion cubic feet of associated natural gas, and 1.6 billion barrels of natural gas liquids distributed in Wolcamp A, Woldcamp B, Wolfcamp C, and Wolfcamp D.

The wells installed with the new technology were drilled and completed Lea County in the Delaware basin and Midland County in Midland Basin (Figure 1). The production profile of the wells produced in this area is characterized by a high initial fluid production with high water cut, low GLR, and high sand production because of the flow back of the frac sand. The conditions change rapidly because of the well depletion using ESPs in the initial completion. Typically, in 3 or 6 months, the profile will pass to a steady fluid production with medium to low water cut and high GLR. At this point, the sand production will depend on the type of producing formation and the consolidation degree of the rock

This kind of profile and the use of ESPs bring common problems such as gas and low volumetric efficiency in the pump. Several operators in the Permian basin face these problems and use the traditional solution such as gas handler in the ESP or mix pump stages to compress the free gas inside the vanes of the impellers, however, when the percentage of free gas at the pump intake is significantly high (>80%), it is difficult to obtain satisfactory results. The new technology introduced in this paper and proved through multiple applications strikes this problem before it reaches the pump intake and forces the gas slugs to disperse into the liquid modifying two characteristics of the fluid: the solubility of the gas and the flow regime.

GAS SLUGS PROBLEM DESCRIPTION

As a result of the massive implementation of horizontal wells due to their advantages, the problems for gas slugs were also generalized along the Permian basin. The flow regimes in a horizontal well are classified as stratified smooth, stratified wavy, slug, elongated bubble, dispersed bubble, and annular. Figure 3 shows the representation of the 6 types of flow regimes and the relation with the liquid and gas velocity in the horizontal section of the well. For two-phase gas-liquid flow in a horizontal well, the most likely flow regimes for toe-up and toe-down wells are stratified and slug flow, respectively. For stratified flow, gas flows on the top portion of the well, and liquid flows on the bottom portion of the well. The gas-liquid interface remains flat for the low gas and liquid flow rate. The interface becomes a crescent shape as gas and liquid flow rates increase causing the liquid phase to climb up along the periphery of the pipe. The liquid level in a stratified flow regime increases as the flow inclination angle increases and decreases otherwise.

Intermittent flow and elongated bubble flow occur when the in-situ gas flow rate is low and becomes slug flow when the in-situ gas flow rate is high. Both slug and elongated bubble flow can be characterized as an alternating flow between the liquid phase occupying the entire flow cross-sectional area and the liquid film that has a gas bubble flow on top. In the case of slug flow, the liquid phase entrains some gas bubbles inside but, there is no gas bubble entrained inside the liquid phase for elongated bubble flow. When the fluids reach the vertical section of the well the flow regimes are similar to those in the horizontal section except for the stratified flow because there is no lower side of the pipe which the densest fluid prefers. This fact implies that when the slugs are created in the horizontal section, they will move through the casing, passing for the curve to the pump that is installed in the vertical section, so despite the fluid column accumulated in the well, when the flow regime is ruled by slugs, the pump will receive frequents amounts of free gas that will degrade its performance (Figure 4). Additionally, we are including a video of a lab test made with Texas Tech University to understand the gas slugs behavior downhole from the horizontal to the vertical path.

When the free gas enters the impellers, the performance of the pump stages is highly affected; first, we will notice a reduction of the head developed by the pump compared to the manufacturer curve. Second, the area available for the liquid is reduced because the gas is expanding and occupying space inside the vanes of the impeller. Because the gas phase is lighter than liquid, it tends to move on the low-pressure sides of the impeller vanes, whereas liquid flows at the high-pressure sides. Small gas bubbles are pushed by the liquid flow toward the diffuser; this is the situation when low amounts of gas enter the pump. As explained previously this is bubble flow and dispersed fine bubbles are moved by the liquid without any slip between the phases. As free-gas volume at the pump intake increases and more small bubbles enter the impeller, the bubble flow is now transformed in slug as a result of the coalescence of the gas bubbles. When the size of these large gas bubbles reaches a critical value, gas becomes stagnant at the impeller intake causing further accumulation of bubbles and formation of a gas pocket. Gas pockets cause unstable operation of the pump stage called surging characterized by the sudden discharge of liquid and gas slugs from the pump and leading to severe equipment failures. If these pockets are not transferred by the liquid flow toward the impeller discharge at a sufficient rate, they will grow in size and can finally completely block the liquid flow through the impeller, and gas lock occurs4. Figure 5.

Summarizing, since the drilling and completion, the well starts with an initial high fluid production, high water cut and low GLR, eventually these turns into a steady production with medium to low water cut and high GLR until the flow reaches the slog pattern flow, then the gas accumulation in the impellers will lead to gas lock and finally to the ESP failure. Of course, before the ESP fails, we need to mention the low productivity of the well because the phenomena described previously that will end in drastic problems like a broken shaft, motor burn, motor grounded, seals damaged, etc.

GAS HANDLER: VORTEX REGULATOR

The Vortex Regulator is a device developed to control the multiphase nature of fluid flowing in the vertical section of the well, where gas flows independent of the liquid phase and therefore more quickly reaches the inlet of the pump. As explained in the previous sections, this phenomenon causes multiple problems and reduces the production of wells installed with ESPs.

This new device is installed below the pump sensor and consists of 5 sections as explained in figure 7. The inlet section, isolation section, pressurization, surge control section and separation of solids section along with the outlet section. The 5 sections are combined to create a unique effect near the pump inlet, delivering an almost homogeneous, single-phase mix of production fluids to the pump. The gas slugs flowing with the liquid are initially retained by the isolation section and accumulated in the neck above the inlet section. In this area, the first mixture of the liquid with the gas is produced when both slugs collide and enter through the slots of the system. The gas slugs are dispersed becoming an elongated bubble flow. The above mixture enters the device and flows downwards, pressurizing the mixture and causing the smallest gas bubbles to re-solubilize and disperse in the elongated bubbles flow created outside the device. The bubbles dispersion is enhanced with the help of the solids separation section where a helix generates a centrifugal force in the fluid, dissipating the bubbles and separating the solids. The homogenized fluid mixture turns into a bubble flow with small and resolubilized bubbles flowing with the liquid. The re-solubilization process of the gas bubbles is optimized by a smaller inner pipe connected to the top of the helix. Over there, the pressurization reaches its maximum value, which increases the solubility of the gas in oil. Table 5 shows how the change in Rs is in this section of the tool and shows how, in addition to the dispersion of the free gas bubbles, there is a re-solubilization of the gas phase within the liquid phase. Finally, the fluid enters the Surge control section which was developed over 2 years back that has internal baffles to confirm resolubilization of gas into liquid phase, along with a unique valve system that helps in maintaining the fluid level above the pump and reduce surging of gas slugs. This device helps in controlling the amount of gas that passes through this equipment which in turn guarantees re-solubilization of gas bubbles that enters this equipment going through the 4 stages of controlling gas slugs.

The inner pipe oversees communicating the sections above and below the packer and it will take the homogenous fluid to the outlet section above the packer (Figure 7). The homogeneous fluid mixture is discharged into the annular fluid column. The almost homogenous mixture will flow upwards to the pump where the gas handlers and gas separators will create a combined effect that would get rid of any significant free gas effects on the pump within the impellers. For the proper design of this device in each well, it is important to consider the following points:

1. Isolation section size. This size is chosen based on casing diameter and weight, depth, and flowing well pressures.
2. The isolation cup material is selected based on temperature and gas and fluid composition
3. The distribution of the slots in the inlet section should guarantee a sufficient open area for the expected fluid volume but be able to disperse the gas slug
4. The diameter of the internal pipe depends on the required pressurization. At higher % of free gas, greater fluid pressurization should be sought
5. The helix is designed for the amount of fluid and the severity of sand production. These two factors are used to choose the pitch area. The device must be connected just below the sensor, as close as possible to the pump intake

In wells installed in deviated areas or just at the KOP, it is important to consider the use of centralizers or swivel tools to ensure correct centralization of the pump and eliminate excessive vibration in the pump shaft. Centralizers can be installed above the pump and below the pressurization and solids separation section. The swivel tool can be installed between the sensor and the outlet section and below the solid separation section

FIELD APPLICATION

Since the start of the development of Well A located in the Delaware Basin in the Wolfcamp A, gas has been a problem for the production performance. Figure 8 shows the sensor parameters of the well, 8 months before the OSI Vortex Regulator was installed. The Motor temperatures were maintained at high temperatures of 200 °F when the ESP was operating, and the gas strongly affected motor cooling. It was clear on how much of a struggle it was for the pump to restart and maintain smooth ESP performance, PIP depletion curve etc. This new condition, with a more depleted field, limited the decrease in PIP due to gas interference in the pump. This intermittency in the operation of the pump and the low fluid recovery caused the analysis of the field conditions to determine what the problem was and how to optimize the operation of the pump.

After reviewing the field diagnosis and evaluating the specific behavior of the well spudded until the third quarter of 2021, it was decided to start the implementation of OSI Vortex Regulator. The design of each well was independently evaluated to decide each of the criteria related to the previous section. In general, the design considered the mechanical state of the well, expected production conditions, and severity of the problem.

Well B was in the Midland basin and was in the later stages of its well life, with GOR values as high as 2275 SCF/STB as shown in Figure 12. It started showing tremendous instability in pump performance as seen by the fluctuating sensor parameters in Figure 13., due to the high amount of gas presence in this well. Then In September 2021 it was decided that a new technology needs to be considered since the well had high ESP production potential. After evaluating the well conditions, it was decided to implement the OSI Vortex Regulator to maximize ESP performance in this well B

RESULTS

The implementation of the new technology in Well A started in the third quarter of 2021 and was monitored till the first quarter of 2022, i.e., 7 months before and after installation of the Vortex Regulator was monitored. The performance evaluation of the tool was made based on the parameters of the ESP sensor. Shutdowns, variations in motor current, variations in frequency, Motor temperatures, production data were analyzed. Figure 8 shows the sensor data for well A from the beginning of October 2021 i.e., after the installation of the Vortex Regulator. In general, the sensor parameters remained stable during the analyzed period. The frequency was kept constant at 50 Hz while the motor temperature did not go above 170 °F. The motor current and the voltage show a stable and constant behavior, that is why the presence of solids and gas interference is ruled out. Normally, gas and/or solids inside the pump stages generate large changes in the amount of power required by the motor. Compared to the behavior of the well analyzed in the previous section, the performance of this well maintains a much more stable trend with fewer shutdowns. Cumulative oil production was increased by 19% in the same period after the OSI Vortex regulator was installed due to lower shutdowns and smoother operating conditions as shown in Figure 9. PIPs were gradually reduced to 470 psi and were maintained without breaking gas at the intake shown by stable motor currents and temperatures as shown in Figure 10. Figure 11. Shows that “0” free gas was present in the production pump which further proves the application of OSI Vortex Regulator assisting in maintaining high ESP performance in gassy wells. Overall shutdowns in this period were monitored and was found to be 120% lesser shutdowns after installing the OSI Vortex Regulator i.e. 45% shut downs before the installation vs 17% after the installation of OSI Vortex Regulator.

In Well B, OSI Vortex Regulator was installed in November 2021, and as seen by the sensor parameters in Figure 14, overall, ESP performance was drastically increased due to less instability because of gas interference. Overall Motor temperatures were stable at 175 °F with less fluctuations compared to pre installation values. Motor Current was stable at 30 Amps, Motor Frequency was stable at 50Hz. After the installation of the OSI Vortex Regulator, it was possible to get higher overall production rate with lower stable frequency as seen in Figure 13. which highlights the drastic improvement in ESP performance after the installation of the OSI Vortex Regulator.

CONCLUSIONS

- Flow regime characterization is a very useful tool to identify problems and generate mitigation plans that reduce adverse effects on production. The information of the diagnostic model can be done for the entire field as shown in this paper or divided by regions depending on the formations, formation pressure, pad or even for each well and thus increase the level of detail and reduce the uncertainty.
- High formation pressure does not guarantee a single-phase flow in the well. Bubble pressure, field depletion curve, and percentage of free gas calculations at the pump intake should be considered to determine at what point free gas problems can occur. This is another option to create the best ESP design from the beginning of the production life of the wells.
- Wells with slug flow in the vertical section are highly susceptible to poor pump performance. Even adding gas separators and handlers to the pump does not solve the problem in cases where the percentage of free gas exceeds 40%.
- To deal with slug flows, the slug must be retained and dissipated into the liquid phase, in this way, the flow will pass from a slug to an elongated bubble flow. Pressurizing and centrifuging the flow helps to completely disperse the gas bubbles in the liquid and re-solubilize a fraction of the free gas. After this process, a bubble flow is obtained, and it can be easily managed by the pump.
- The use of the vortex regulator in the later stages of well life where gas formation increases, radically improves pump performance. The operating parameters were kept stable; therefore, the equipment's run life was greater.

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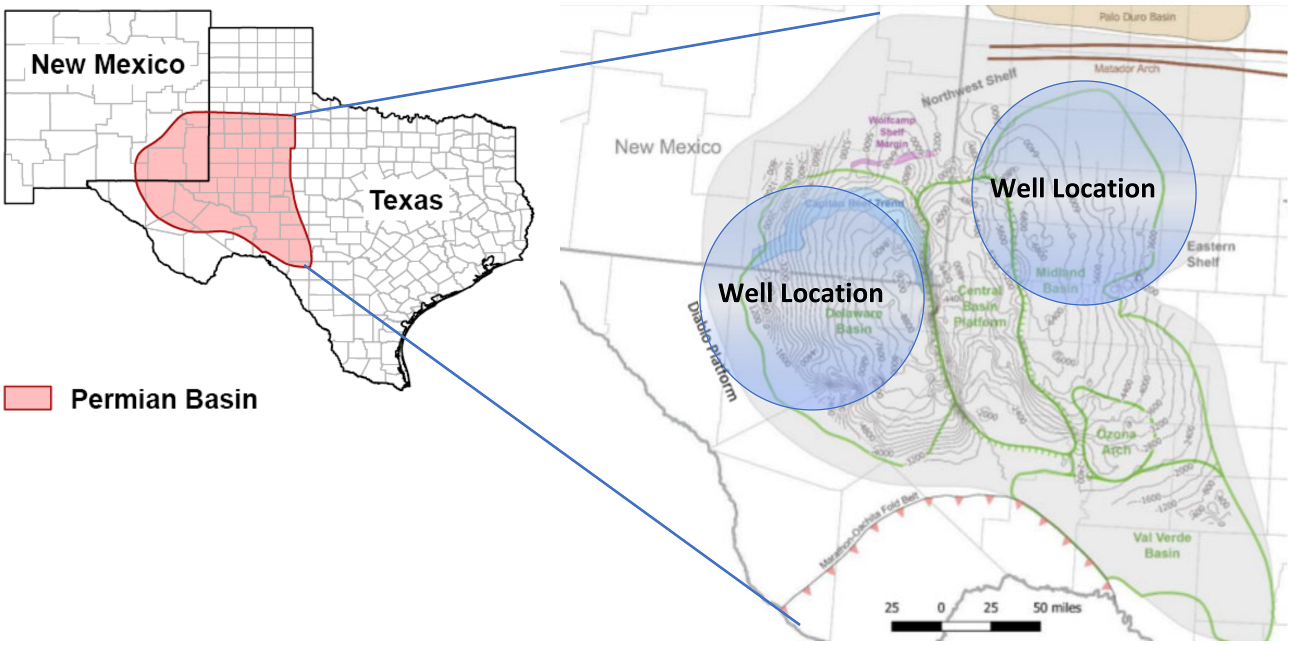


Figure 1 Wells Location (U.S.Energy Information Administration based on drilling Info)

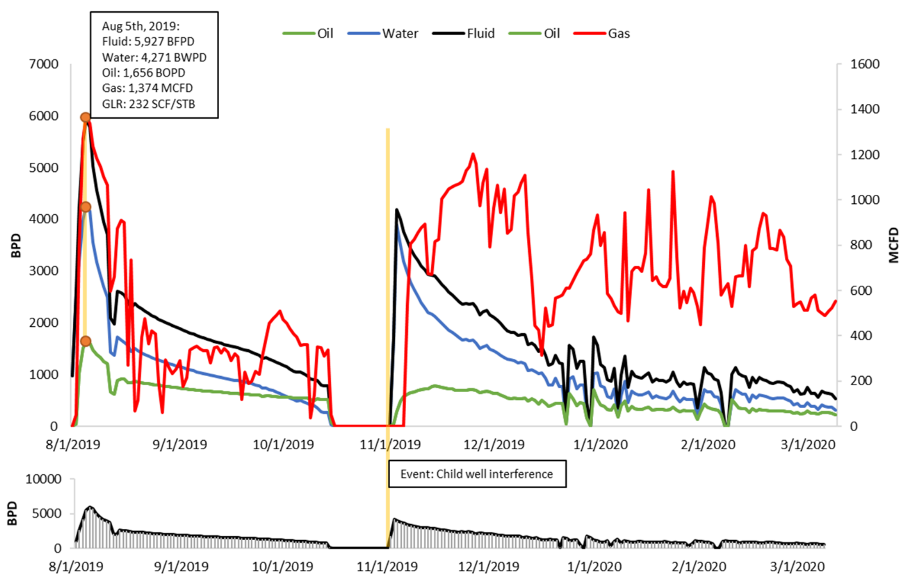


Figure 2 Production profile, Midland basin

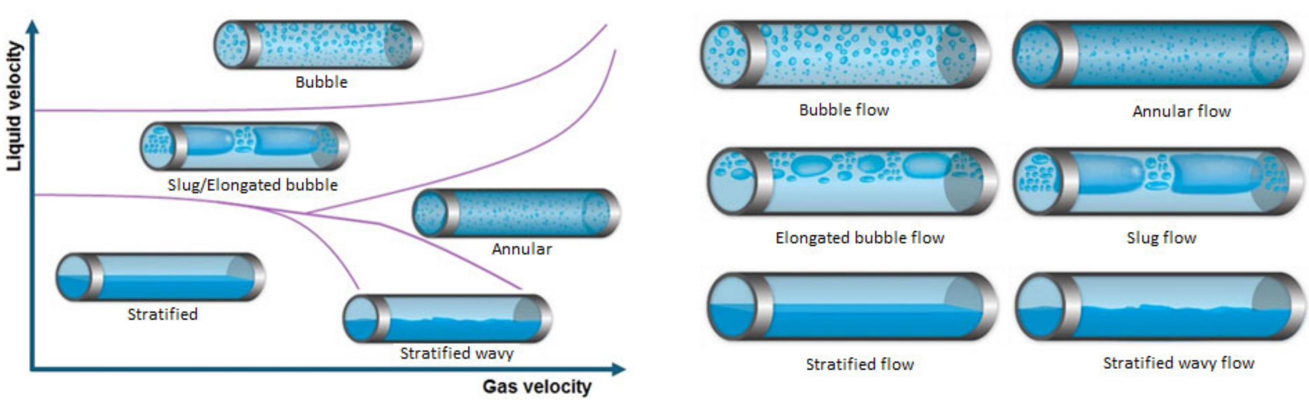
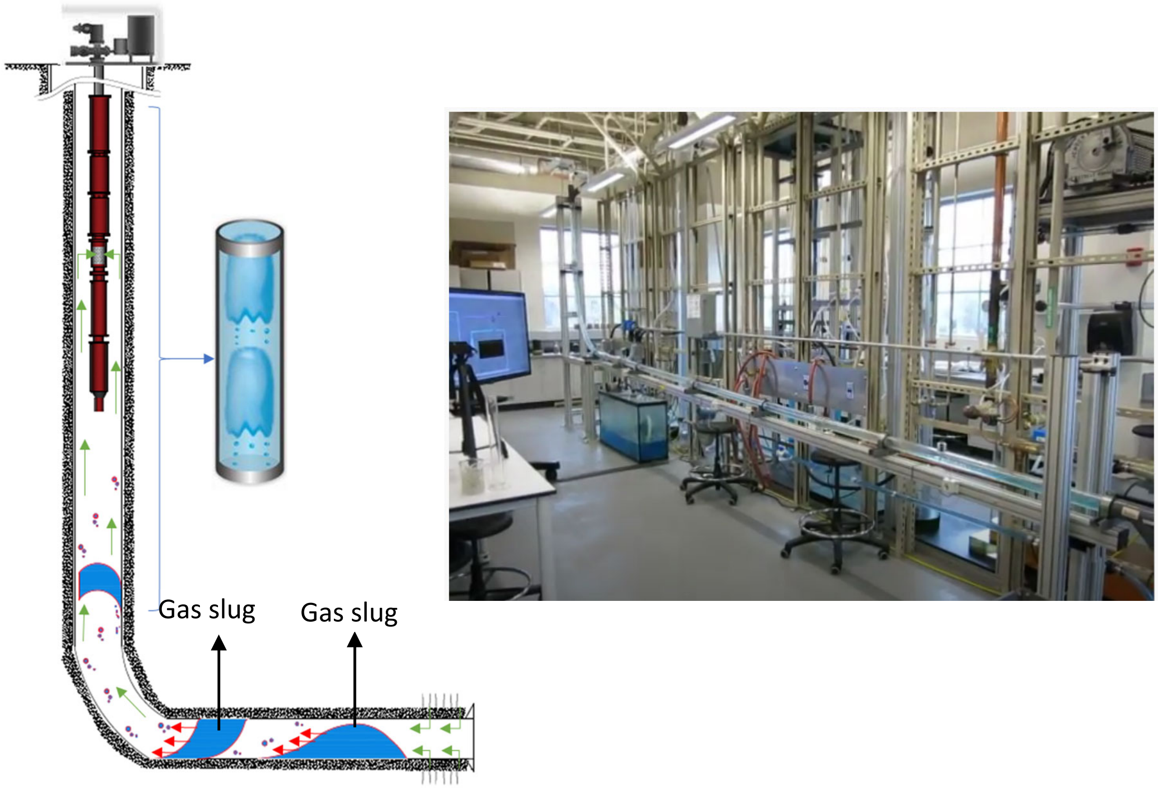


Figure 3 Flow regimes in horizontal pipes (Source: Pipe flow 2)



https://www.youtube.com/watch?v=MKHpCggHtLc&feature=youtu.be

Figure 4 Gas slugs flowing to the pump

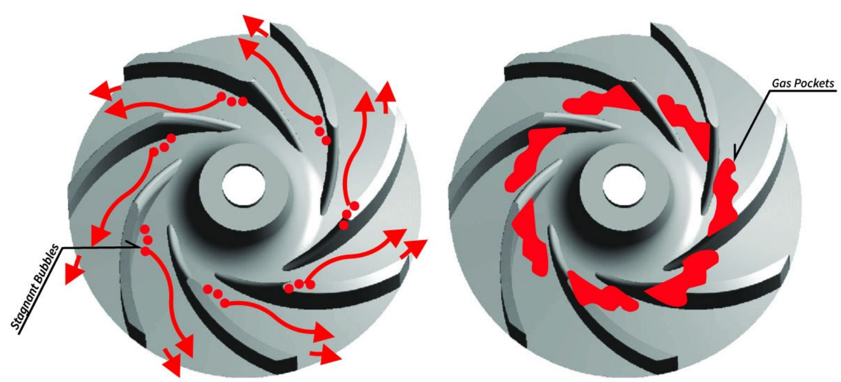


Figure 5 Gas effect on centrifugal pumps

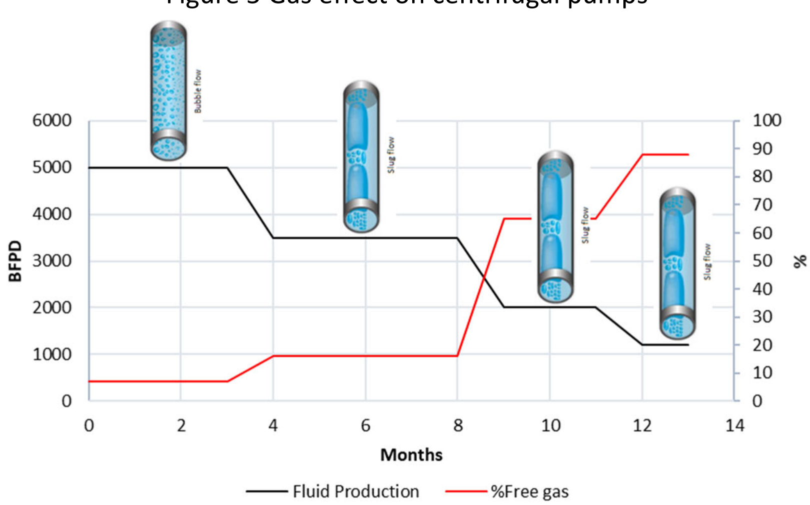


Figure 6 Field behavior

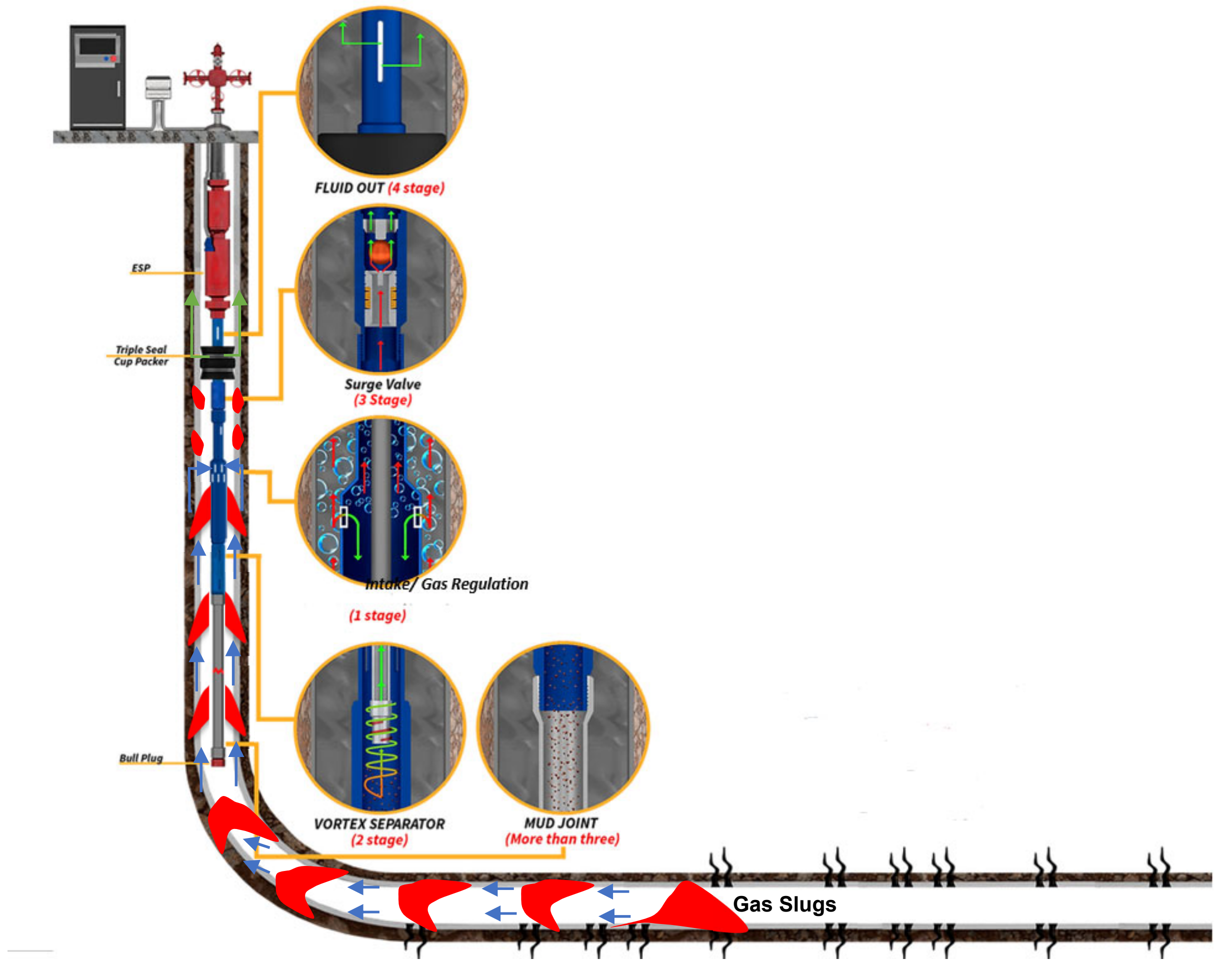


Figure 7 Vortex Regulator Sketch and flow path

Figure 8 Before and After Sensor Parameters of Well A

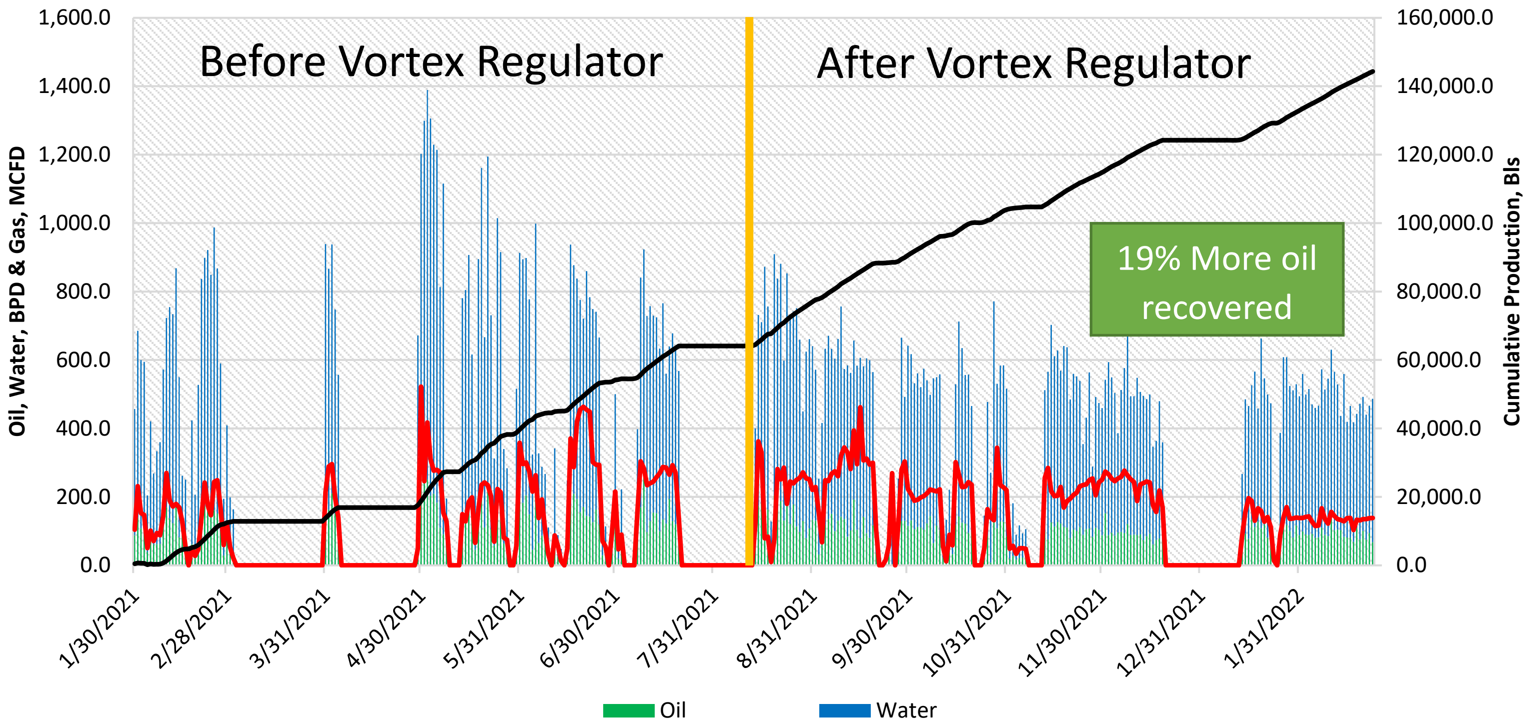


Figure 9 Before and after production values from Well A

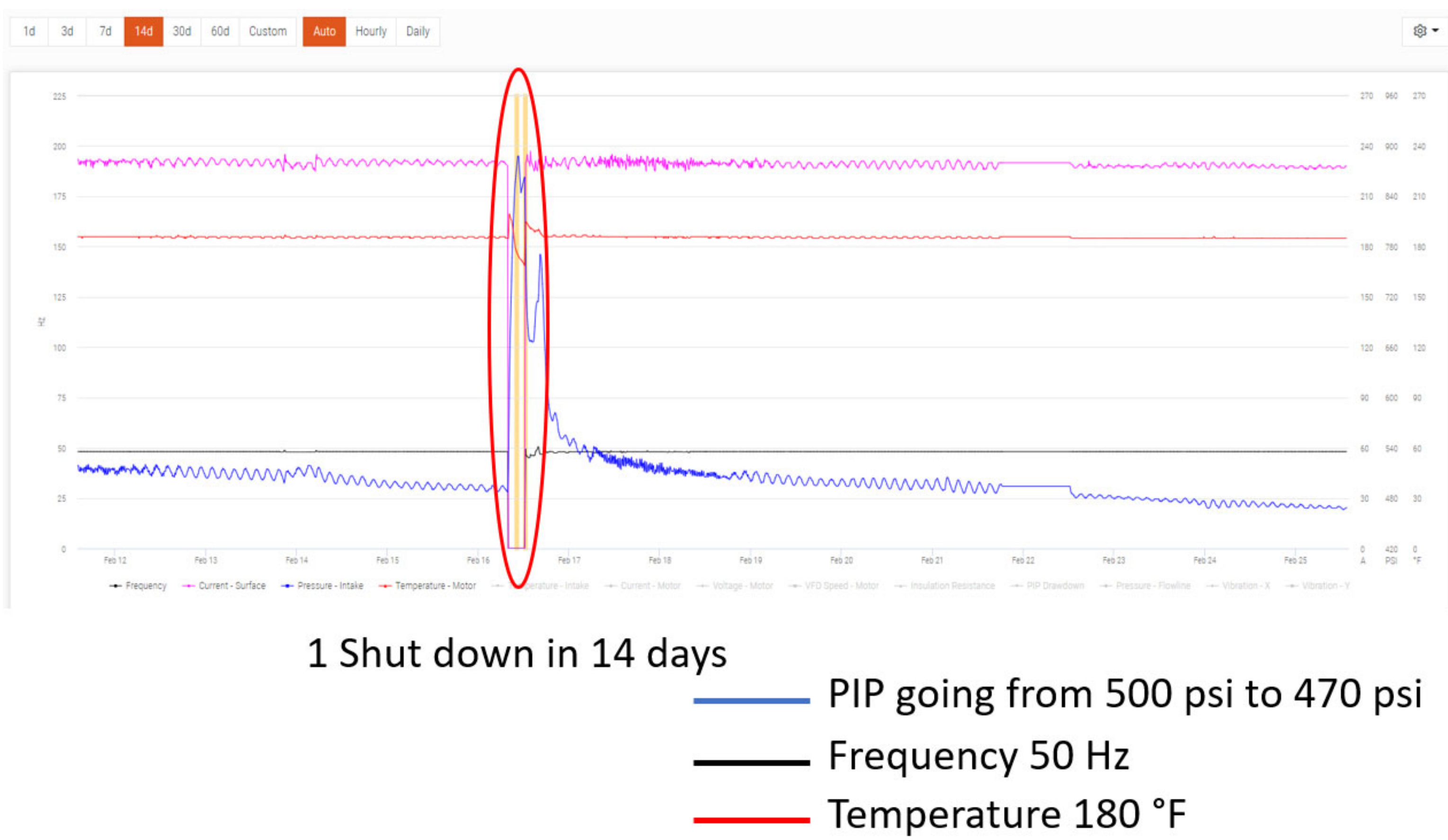


Figure 10 Vortex regulator latest performance evaluation on well A

	Intake	Separator 1 Discharge	Separator 2 Discharge	GKX Discharge	Charge Pump1 Discharge
Separator Efficiency (%)		50	40		
Natural Separation Efficiency (%)	0				
Rs (scf/bbl)	171.47	171.47	171.47	212.06	771.015
Bg (bbl/mcf)	4.734	4.734	4.734	3.883	0.562
Bo (bbl/stb)	1.119	1.119	1.119	1.138	1.433
Volume Of Gas (bpd)	576.36	288.18	172.91	127.1	0
Volume of Oil (bpd)	104.48	104.48	104.48	106.28	133.83
Volume Of Water (bpd)	373.6	373.6	373.6	373.6	373.6
Total Fluid Volume (bpd)	1054.44	766.26	650.99	606.98	507.43
Free Gas / GVF (%)	54.7	37.6	26.6	20.9	0
GOR (scf/stb)	1475	823.235	562.529	562.529	771.015
GLR (scf/stb)	295	164.647	112.506	112.506	154.203
Liquid Phase Density (lb/ft^3)	68.699	68.699	68.699	68.5498	66.7698
Gas Compressibility	0.895	0.895	0.895	0.87	0.422
Pressure (psi)	445.323	445.323	445.323	562.858	2343.795
Final Composite SpGr	1.1177	1.1177	1.1177	1.1177	1.1177
Final FLOP (ft)	1174.579				
Final Temperature (°F)	152	152	152	152.128	157.013

Figure 10 Shows free gas value in production pump as "0" in Well A

WELL CONDITIONS		
CASING 20#	5-1/2	IN
CASING DRIFT	4.653	IN
TUBING	2-7/8	IN
FLUID RATE	610	BFPD
WATER RATE	352	BFPD
OIL FLOW	258	BOPD
GAS FLOW	587	MCFD
WCUT	57.7	%
GOR	2,275	SCF/STB
GLR	963	SCF/STB
SENSOR DEPTH	8,177.87	MD FT

Figure 12 Well B Initial Conditions

WELL PRODUCTION RATE			
BEFORE OSI VORTEX REGULATOR			
DATE	OIL	WATER	GAS
8/6/2021	258	352	298
8/10/2021	209	284	275
9/13/2021	153	214	328
10/17/2021	196	267	446
AFTER OSI VORTEX REGULATOR			
DATE	OIL	WATER	GAS
12/22/2021	219	406	526

Figure 13 Well B Production Rate

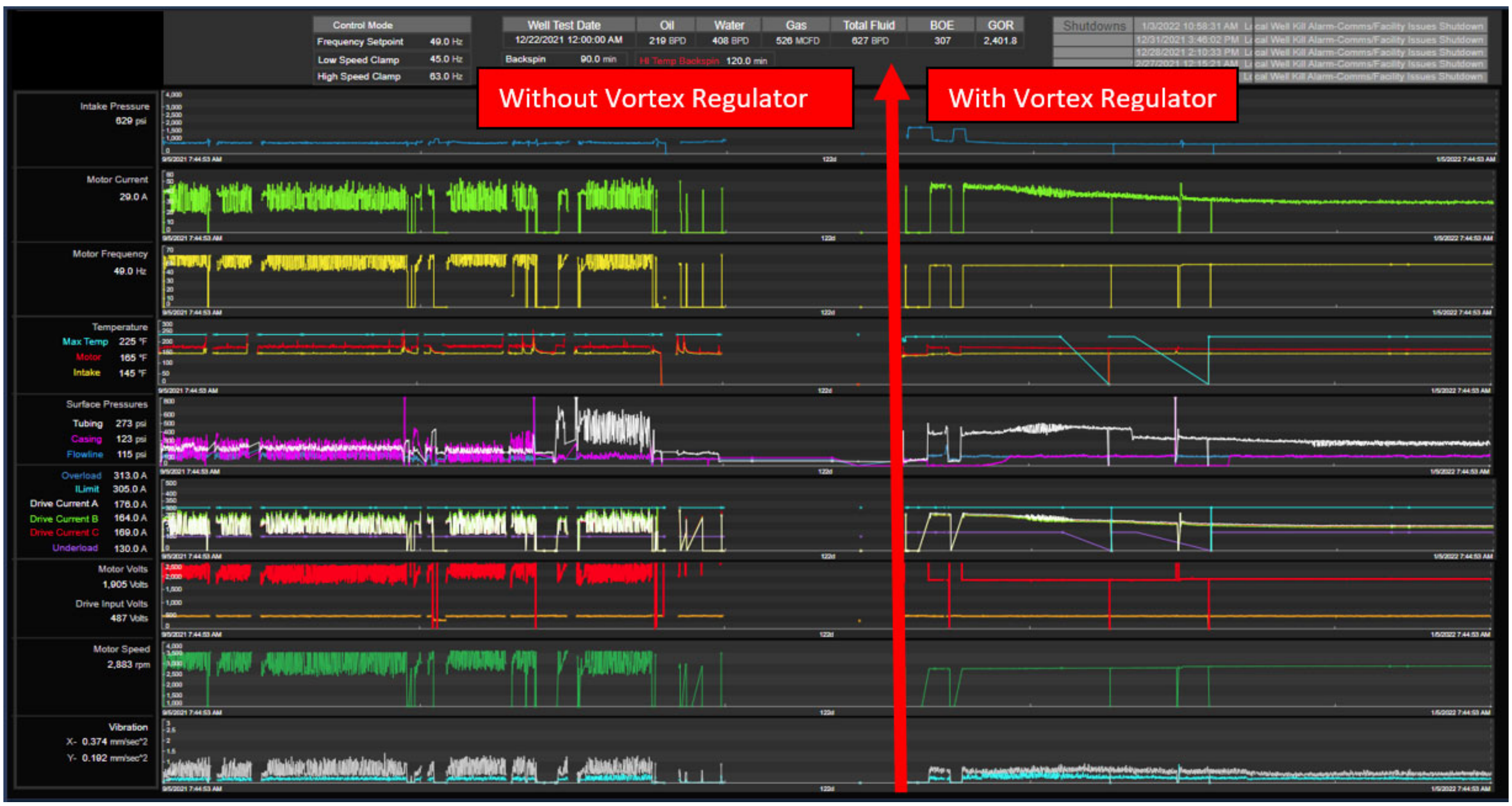


Figure 114 Before and after installation of OSI Vortex Regulator on Well B