REDUCING PIP BELOW 600 PSI BREAKING AND SEPARATING THE GAS SLUGS THROUGH THE APPLICATION OF AN INNOVATIVE GAS SEPARATOR TECHNOLOGY IN ESP: CASE STUDIES IN THE PERMIAN BASIN

Carlos Loaiza, Chevron
Gustavo Gonzalez, Shivani Vyas, Odessa Separator Inc.
Roger Maxim, Summit ESP

ABSTRACT

High gas-liquid formation ratios appear as the fluid level decreases and as a result, a significant decrease in pumping efficiency is seen in the ESPs. This problem forces frequent shutdowns in the pump because the gas is incapable of adequately cooling the motor and this forces the companies to maintain high fluid levels to avoid the formation of free gas at the pump intake, which increases the PIP and limits the production of fluid. A new and innovative downhole gas separator has been introduced in recent applications to treat gas slug's problems. For these applications, a shrouded ESP with a double stage of gas separation connected to the bottom of the shroud as intake was designed to break and separate gas slugs and avoid gas entering into ESPs by forcing free gas to go around the shroud and produce through the casing. The gas separator uses an innovative design to break the gas slugs in the annular section between the casing and the tool, (additionally) with the internal dual flow system, the separation efficiency increases while it creates a chamber lift filled with free gas liquid.

With this new system, the fluid is now forced to pass through an additional gas separator which helps to separate gas and keep lower PIP than usual, promoting fluid production in the wells. This work presents the application of this new technology on 2 Wells with gas problems and the PIP behavior is presented as an improvement after the installation of the New Gas Separation Technology.

INTRODUCTION

Wells with a high gas – liquid ratio have become more and more common over the years. Normally this is related to either exposed gas sands, secondary gas cap, producing below the bubble point pressure and/or depleted reservoirs where water injection projects have been applied and the values for the water cut are high[1]. In order to make a profit, the oil companies have to produce a large amount of fluid to achieve a positive NPV (Net Present Value) and the Electro submersible pump facilitates high flow rates making this artificial lift system one of the most important in the present market. The ESP has proved to be an efficient means of producing fluid from Oil and Water wells, however, the presence of free gas does affect the functionality of the heart of the ESP, the centrifugal pump; the pump rotational speed decreases which drastically reduces the pump efficiency. Research and tests have shown that when the free gas to liquid ratio reaches approximately 10% by volume at the pump, the performance of the pump deteriorates. At lower ratios, the pump can be expected to perform very well without difficulty[2].

This work presents a revolutionary system that works in conjunction with the ESP to handle high GOR and GLR wells. This system combines the use of both static and centrifugal gas separation techniques, to maximize the efficiency of the system and prolong the life of the ESP. The new technology includes the ability to handle both solids and gas problems inside of a well using an encapsulated ESP to force the fluid to flow in specific patterns, thereby manipulating the fluid to behave in a predictable manner to achieve the desired results.

WELL CONDITIONS

This specific research work will focus on wells that are producing with a pump intake pressure over 600 psi. Normally wells with high GOR and GLR present gas occupying space that should be occupied by liquid, which causes a low pump efficiency. As we can see in figure 1, 35% of the ESP failures in the Permian basin are related to motor heat caused by the presence of gas in the impeller of the pump[3], therefore the well's operator decides to maintain a high PIP with a high fluid column but restringing the lifting capacity of the system. The use of the New Gas Separation Technology will allow us to reduce the PIP smoothly until we reach a possible PIP interval of 200 to 600 psi depending on the conditions of each well and maintaining motor parameters consistently. It is important to mention that there are some factors that are crucial to take into consideration, such as whether the well is vertical or horizontal. Nowadays, most of the wells with high fluid volumes are a product of fracturing a horizontal zone which causes an intermittent gas fluid production, as test and simulation has proved a slug flow is the most common in horizontal sections[4], this research will present all these conditions and how it was analyzed to implement a new technology that can handle high GOR and GLR and at the same time maintain a low PIP, in order to maximize pump efficiency.

NEW GAS SEPARATION TECHNOLOGY

It is important to empathize that it is imperative to separate as much free gas as possible before the gas reaches the pump intake, otherwise, the gas lag behind in the lower pressure areas of the pump stages eventually will fill and block the pump stages which can end up in a shutdown of the ESP[2] system. The New Gas Separation Technology presents a special design that separates gas through three separation stages; before the separation stages a shroud needs to be installed to restrict the fluid to flow towards the first stage of separation, the shroud is an encapsulation body that increases the velocity of the fluid and also ensures optimum motor cooling and extended system run life, especially at lower rates. The flow path is redirected to the Intake section (Tubing Screens), the fluid flowing downwards looking for the screen intake generates a natural gas separation associated with the relation between the casing and the specific diameter of that section.

(1) The screen section which is made up of a screen jacket is placed over perforated tubing with EUE thread with a different diameter option such as 2-3/8", 2-7/8" and 3-1/2". The screen section comprises a tubing screened in V manufactured on 304-stainless steel mesh where the fluid enters thought and by mechanical action, the gas bubbles collide and then flow down inside the housing of the tubing screen (Figure 2). On the next separation section, the bubbles would be bigger so it would be easy to separate the fluid from the gas by the action of gravitational forces and the difference of density.

The next section (2) can be described as the stage where most of the gas separation takes place and it is a design of two gas separation sections of 24 ft each, one that possesses a special geometry that facilitates a dropdown pressure due to Venturi effect that is caused by the change of diameter in the pipe from a smaller diameter to a bigger diameter as we can see in figure 3. This change of diameter between Neck and Body turned reducing the velocity of the fluid less than 0.5 ft/s using Bernoulli's principle and providing all the conditions for the gas bubbles to rise up to screen section and migrate to the casing. Additionally, while the fluid is flowing through the separation chambers, it passes through a modified coupling system, which is an innovative and essential component as shown in figure 4. This simulates the impeller of the ESP and was designed to print a circular movement to the fluid, producing the necessary turbulence to promote the coalescence of gas bubbles again making the migration towards the outlet points much easier.

After passing through the separation sections, the fluid enters the last stage of gas separation i.e. into a centrifugal separator. This centrifugal separator is responsible for creating a centrifugal effect that separates the gas bubbles before the fluid enters the dip tube as shown in figure 5. When the fluid enters the last separation section before entering the dip tube, it is conditioned in such a way that it maintains its velocity of 1 ft/ s. When the fluid enters the dip tube with this velocity the pressure drop forces the free gas to get back in solution and enters the dip tube as solution gas. The same velocity maintained through the dip tube helps the motor to get an effective cooling process and avoid shutdowns due to overheating in the system. As a rule of the thumb, maintaining a flow velocity greater than or equal to 1 ft/s ensures effective cooling of the pump motor, since the surrounding fluid is quickly recirculated, and a hot surrounding environment is avoided. The whole assembly is shown in figure 6 and 7 highlighting the flow path of the fluid.

It is crucial before running The New Gas Separation Technology to check all the items on the design criteria[4], Figure 8. shows the information that needs to be provided alongside the well deviation survey, failure and intervention report, sand sieve to determine the best slot size to filtrate sand and any information related to the well history to have a good understanding about the global issue and provide the best solution.

The first change that the New technology needs in order to be installed is the shroud, as it was mentioned before, the shroud plays a crucial part in the success of this new system because this ensures the proper cooling of the motor but in order to do that it has to be a minimal distance between the Shroud ID and the Motor OD, in order to achieve an effective heat transfer. If the distance is too short the fluid will not be enough to cool the motor neither will be if the distance is too long and velocity cannot achieve optimal values. Depending on the casing size there is some minimal distance between the OD of the Motor and the ID of the shroud, and the casing drift and the OD shroud (See figure 9). As it is well known, each company manages its own standards but the thickness of the shroud in the market is normally 0.15 and 0.30 inches and based on this information a minimum distance of 0.195 inches is required between the Motor OD and the Shroud ID, to attain the minimum velocity to obtain an adequate electrical motor cooling.

Right below the shroud connection the intake section would be installed, there are 2 tubing screens of 50 Slot each, which is the one recommended for this specific application, however, if the conditions require a different slot size it can be modified to enhance sand separation. The length of each Tubing screen is 23.5 and an 1814 in^2 of total open area 907 in^2 each screen section (2-7/8" Tool), the diameter of this tool will depend on the casing and flow rate that the well manages (See table 1), it is important to highlight that the volume management can be higher increasing the total open area in the intake which is totally possible. Depending on the fluid rate and the well conditions the technology data model advises a maximum velocity of 0.24 in/sec to achieve best operational conditions which are approximately 3780 BFPD, nonetheless, with a total open area of 2721 in^2, the 0.24 in/sec velocity condition correspond to a flow rate of 5700 BFPD.

The main separation section is composed of two bodies with standard connections (2-3/8", 2-7/8" and 3-1/2") and different sizes for the diameter of each Body; the greater the diameter is the slower would be the velocity of the fluid flowing through the separation section tool, however, this tool is restricted by the casing size. Depending on specific conditions of the well, the best configuration would be chosen. (Table 2).

The centrifugal desander which is the last stage of the New Gas separation technology, contains a helix inside of the tool that generates a centrifugal movement due to the flow of fluid, that creates a centrifugal force, which then optimizes the gas separation and separates the smallest sand particles which pass through the tubing screen, the helix size will depend on the relationship between the ID of the tool and the OD of the helix and the flow rate of the well. Below the centrifugal desander, it is imperative to calculate the right amount of mud joints that will stockpile all the sand that will be separated, this calculation is based on the sand production rate of the well.

Regarding the process of breaking the slug as it is shown in figure 10. In the process 1 – 4 The New Gas separation technology breaks the gas slugs before this reaches the pump intake, on stage 1 we have the Fluid and Gas coming out from the perforations, due to the high presence of gas a gas slug flow is created as we can see in stage 2, this behavior is really common in horizontal wells, a slug flow is created caused for the free gas and the geometry of the well, in stage 3 when the mixture of fluid and gas enters the gas separation system using the 50 slot intake section the coalesce of the gas bubbles starts and part of the slug will break, and then on stage 4 the configuration breaks the slug remaining and it forces the gas to enter to the gas separation system or to flow through the casing. With this process, the system breaks and separates the gas before it enters in the tool configuration

CASE STUDIES

WELL A

The well is located in the Permian Basin of Yoakum County, Texas, it is a horizontal well drilled through the formations of Salt, Tansil, Yates, 7 Rivers, Grayburg and Sand Andres with a total vertical depth of 9820 ft. The well had an electrical submersible pump 338 series SF1750AR 316 stage. All the information used to analyze this specific case before running the New Gas Separation Technology is in Table 3. According to the sensor parameters on figure 11, the motor temperature for the last 4 months has an average of 182.3 F with a max. of 279.9 F. Elevated temperatures indicates a high presence of free gas due to the heat transfer in presence of gas is slower than in presence of liquid. Let's consider that for every 18F of operating temperature increase, the life of insulation material is reduced by 50%[5].

The presence of high free gas around the pump is the reason why the variables of the sensor show a high variation is some periods. The effort made by the pump to produce the fluid is increased and the power demanded to these conditions is higher[6]. There is an increase in the PIP as well, most likely product of a bigger fluid column which means a lower efficiency of the pump caused by the presence of gas or the limitation of the operator to increase the motor frequency and reduce the fluid column which will produce a higher gas release, in the last month as we can see there is a 200 psi increase from july-3 to july-29, all these symptoms drive the investigation to find a solution that stabilizes the motor parameters and decrease smoothly the PIP to achieve better efficiency.

The configuration for this specific well according to the ESP isolation concept explained before is showed in figure 12. And the description of each stage and part of the tool is presented in table 4.

WELL B

The well is located in Permian Basin of Andrews County, TX. All conditions are summarized in Table 5. This well had a history of high motor frequency showing a continuous fluctuation in between 47-65 Hz portraying large variation in motor current from the presence of lower density fluid i.e. free gas. The motor temperature ran a high of 280 F hotter than normal motor temperature indicating the presence of gas. While the pump intake pressure had a high of 752.5 psi indicating a gradual decrease in fluid production and increase in gas; resulting in the requirement of larger energy to load the fluid into the pump intake as shown in Figure 13. The solid lines in the figure blow indicate the average behavior of the well, while the shaded areas indicate the variation in the same period.

The same configuration was run for well B (Table 5), The well geometry before installation of new gas separation tool consisted of ESP unit with 456 motor series of O.D. of 4.56" and intake 400 series into a casing 5-1/2" with a drift of 4.767". An intake section of 338 series with motor 375 series with 3.75" on ESP was recommended with a shroud of thickness 0.15". This gave a linear distance of 0.195" on each side between shroud ID and pump motor O.D. and 0.1925" (Figure 14.)

RESULTS:

After the installation of the New Gas separation technology, we achieve the next improvements in Well A.

- The average fluid production of the well before the New Gas Separation installation was approximately 800 BFPD after the installation, the well-produced an average of 1100 BFPD until the monitoring activity ended (9 months).

- The pump intake pressure has been reducing (Figure 15) from 600 psi to 294.6 psi since the tool's installation. This could mean, a reduction in the fluid column due to the higher efficiency of the pump.

- After the installation, motor temperature not only has been stable for a longer period, else it has kept a lower value passing from 193 F to 122 F after the installation.

- The reduction and balance in the motor temperature will reduce the risk of problems due to scale deposition around the motor and the pump intake.

- The increase in the motor voltage is caused by the increase in the frequency of the pump. This behavior is normal when the motor frequency is increased to get more production of fluid.

- Less free gas at the pump intake means less effort and power requirement to lift the fluid volume for this reason even when the motor frequency increased the motor current has maintained stably without severe oscillation.

In general, an excellent performance is shown in the sensor parameters, proving the effects and capacity of the new gas separation tool combined with the ESP installation.

After the installation of the New Gas separation technology, we achieve the next improvements in Well B (Figure 16).

- The well had an average fluid production of 600 BFPD and after the New Gas Separation technology, the well presented an average fluid production of approximately 900 BFPD for 8 months Figure 18.

- The PIP before the installation presented a maximum value of 752 psi, after the installation of the new Gas separation technology, it was possible to reach 549 psi, which indicates a reduction on the fluid column due to the increase on the pump efficiency (Figure 17).

- After the tool's installation, the motor temperature has been stable for a longer period of days in between 135.5 F to 146 F compared to constant fluctuation between 179.3 F and 292.6 F. Average motor temperature has almost dropped by almost 100 F

- After the tools installation, the fluctuation on the motor frequency has changed. Motor frequency has been constant at an average of 45.12 hz, whereas the last month before installation of tools, a dramatic fluctuation was observed at 65 hz causing the ESP to shut down after every several hours. Motor frequency has been observed to remain stable lately, which prevents ESP shutdown, increasing pump efficiency in last month.

CONCLUSIONS:

- The application on WELL A and WELL B it was possible to reduce the free gas and increase the efficiency of the pump decreasing the PIP of both wells.

- By applying the New Gas Separation Technology, it was possible to reduce the amount of free gas entering into the pump measured by the stabilization of the motor temperature and the motor frequency.

- The encapsulated system keeps the motor, cool, and prevent slugs of gas entering into the pump intake directly keeping the operation of the system stable. The design of the shroud should be appropriately selected in accordance with the O.D. of the casing and O.D. of the pump motor.

- New tools such as The New Gas Separation Technology has proved to be an efficient gas separator using multiple gas separation stages.

- New technologies such as the one presented in this research improve the run life of problematic wells with high gas content, that presents multiple shutdowns due to poor cooling or maintaining a high PIP to prevent producing gas but limiting the well capacity, by preventing shutdowns and increasing the lifting efficiency the project can attain a positive NPV in terms of lifting cost, if the problem at hand is caused by free gas.

REFERENCES

1. Gustavo Gonzalez, Randy Simonds, Diego Pinto. Odessa Separator Inc, “Static Gas Separation Increases ESP Efficiency in Colombian Field” SWPSC 64 Annual Meeting, 2017.
2. A Simple Method for Predicting Gas/Oil Ratio (GOR) of Electric Submersible Pumping (ESP) Oil Wells, Said K. Salem (King Saud University) | Osman F. Osman (Petronas Carigali Sdn Bhd) 2013, SPE Saudi Arabia Section Technical Symposium and Exhibition, 19-22 May, Al-Khobar, Saudi Arabia.
3. D.W. Kimery and J.C. Saponja, R.C. Chachula, C. Jensen. Breaking the 800 psi ESP PIP Barrier: how to prove flow-conditioning technology can dramatically improve ESP performance in horizontal wells 2017.
4. Odessa Separator Inc. http://www.odessaseparator.com.
5. Gabor Takacs. Electrical Submersible Pump Manual 1st Edition, 2009.
6. S. K. Salem, O. F. Osman. A Simple Method for Predicting Gas/Oil Ratio (GOR) of Electric Submersible Pumping (ESP) Oil Wells, SPE 168062-MS. 2013
7. Steven C. Kennedy, Zachary T. Madrazo, Cristin Rhinehart, Brian Hill, Chelsea M. Grimm, Chris Smith. New ESP Gas Separator for Slugging Horizontal Well,
8. Alhanati, F. J. S.: Bottomhole Gas Separation Efficiency in Electrical Submersible Pump Installations. Ph.D. Dissertation, University of Tulsa, 1993

Table 1. Fluid velocity through the screen section

50 Slot Tubing Screen Section	
2-7/8"	
Flow Rate (Bfpd)	Fluid velocity (in/sec)
3200	0.1981
3000	0.1857
2500	0.1547
2300	0.1423
2100	0.1299
2000	0.1238
1800	0.1114
1600	0.0990
1500	0.0929
1400	0.0867

Table 2. Gas separation section Neck-Body diameters

Gas separation Section Neck	Gas separation Section Body
2-3/8"	3"
2-7/8"	3-1/2"
	4"
	4-1/2"
3-1/2"	4-1/2"
	5-1/2"

Table 3. Well Conditions WELL A

WELL CONDITIONS WELL A		
CASING	5-1/2	IN
CASING DRIFT	4.653	IN
TUBING	2-7/8	IN
AVERAGE FLUID RATE	1470	BFPD
TARGET OIL PRODUCTION	170	BOPD
TARGET WATER PRODUCTION	1300	BWPD
GAS FLOW	510	MCFD
WCUT	88	%
GOR	3000	SCF/STB
GLR	347	SCF/STB
API	32	
PUMP INTAKE	4777	FT
BOTTOM PUMP	4855	FT
LL	3677	FT
TOP OF PERFS	5600	FT
KOP	4800	FT
THP	350	PSI
CHP	150	PSI

Table 4. New Gas Separation technology configuration for WELL A

Well A
2-7/8" x 23.5' x 50 Slot INTAKE SECTION
2-7/8" x 23.5' x 50 Slot INTAKE SECTION
2-7/8" x 3-1/2" SEPARATION SECTION
2-7/8" x 3-1/2" SEPARATION SECTION
2-7/8" x 2' VORTEX GAS SHIELD W/ DUAL FLOW W/ HELIX 2.8

Table 5. Well Conditions WELL B

WELL CONDITIONS		
CASING	5 1/2	IN
CASING DRIFT	4.767	IN
TUBING	2 7/8	IN
AVERAGE FLUID RATE	1000	BFPD
AVERAGE OIL PRODUCTION	60	BOPD
AVERAGE WATER PRODUCTION	940	BWPD
AVERAGE GAS FLOW	650	MCFD
WCUT	94	%
GOR	12500	SCF/STB
GLR	650	SCF/STB
API	39	
PUMP DEPTH	8370	FT
FLAP	1300	PSI
TOP OF PERFS	8581	FT
THP	350	PSI
CHP	0-500	PSI

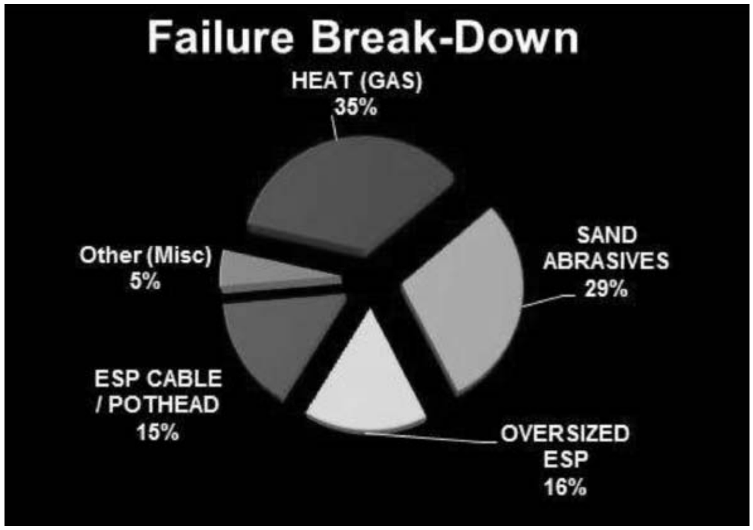


Figure 1. ESP failure analysis from a Permian operator

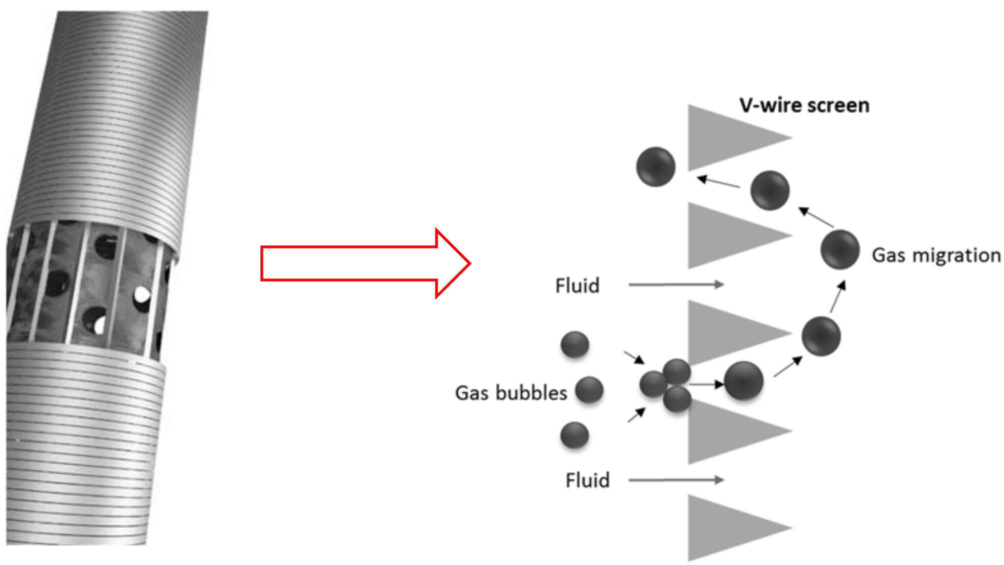


Figure 2. Intake Section (Tubing Screen) Coalescence Concept

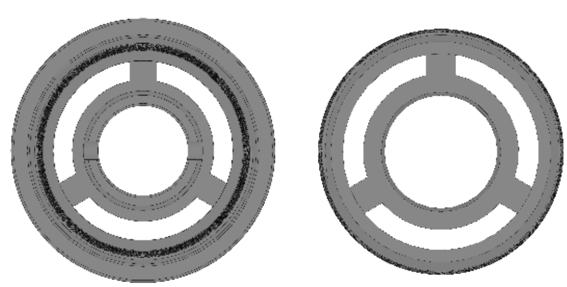


Figure 4. Modified Collar and Nipple with circular pattern slots

Figure 3. Separation Section

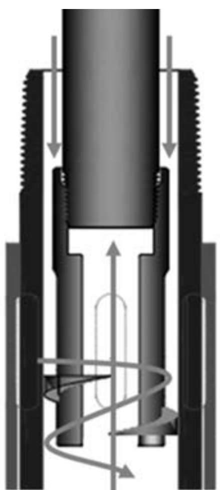


Figure 5. Centrifugal separator

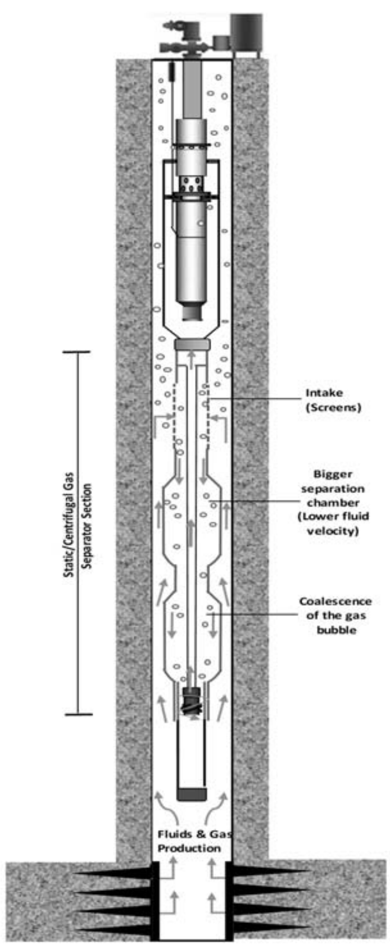


Figure 5. Flow path of the New Gas Separation Design

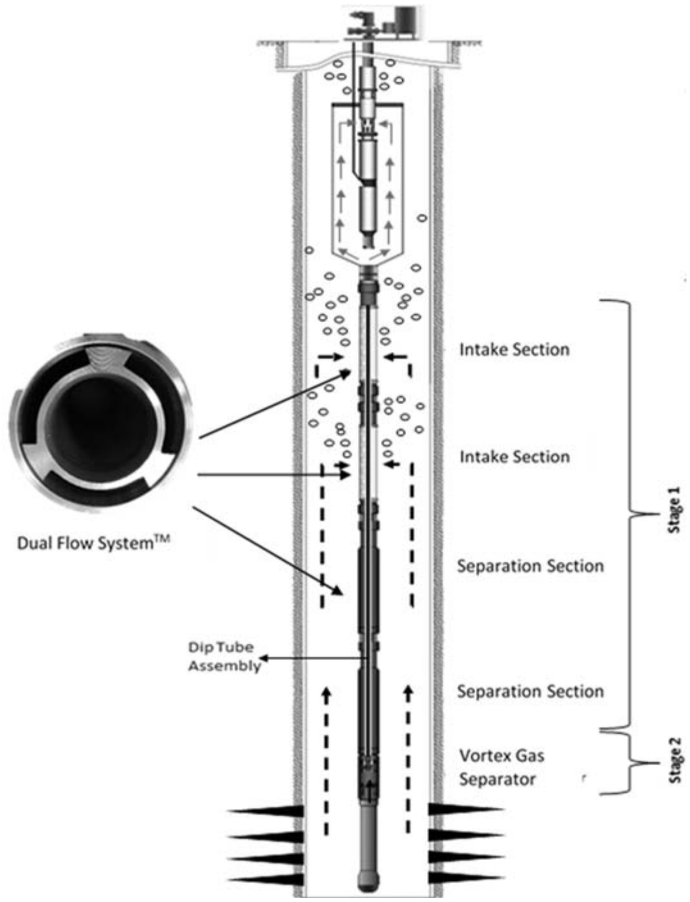


Figure 4. New Gas Separation Design Components

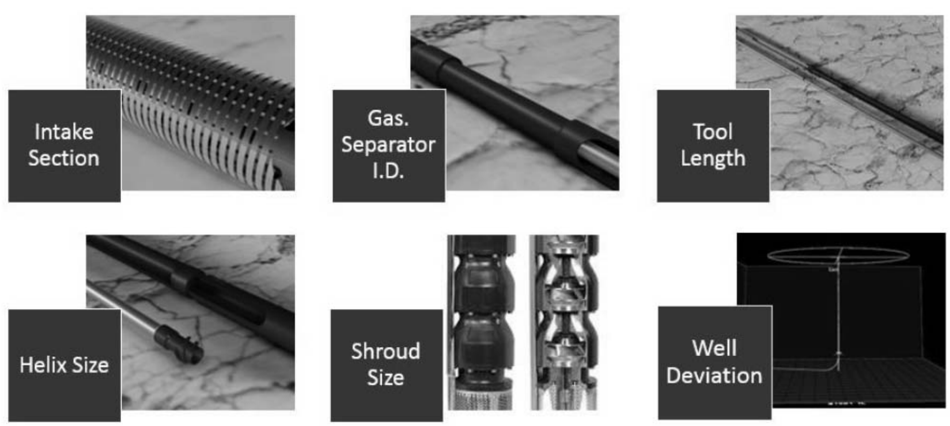
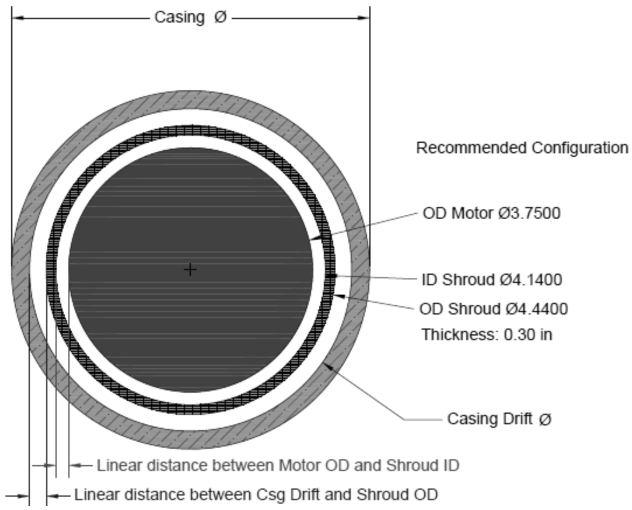


Figure 6. Design Criteria for New Gas Separation



CASING SIZE	Max. SHROUD O.D.	Max. MOTOR O.D.
9-5/8”	7-5/8”	5.62”
7”	5-1/2”	4.56”
5-1/2”	4-1/2”	3.75”

Figure 7. Well Geometry Recommended for the New Gas Separation Technology

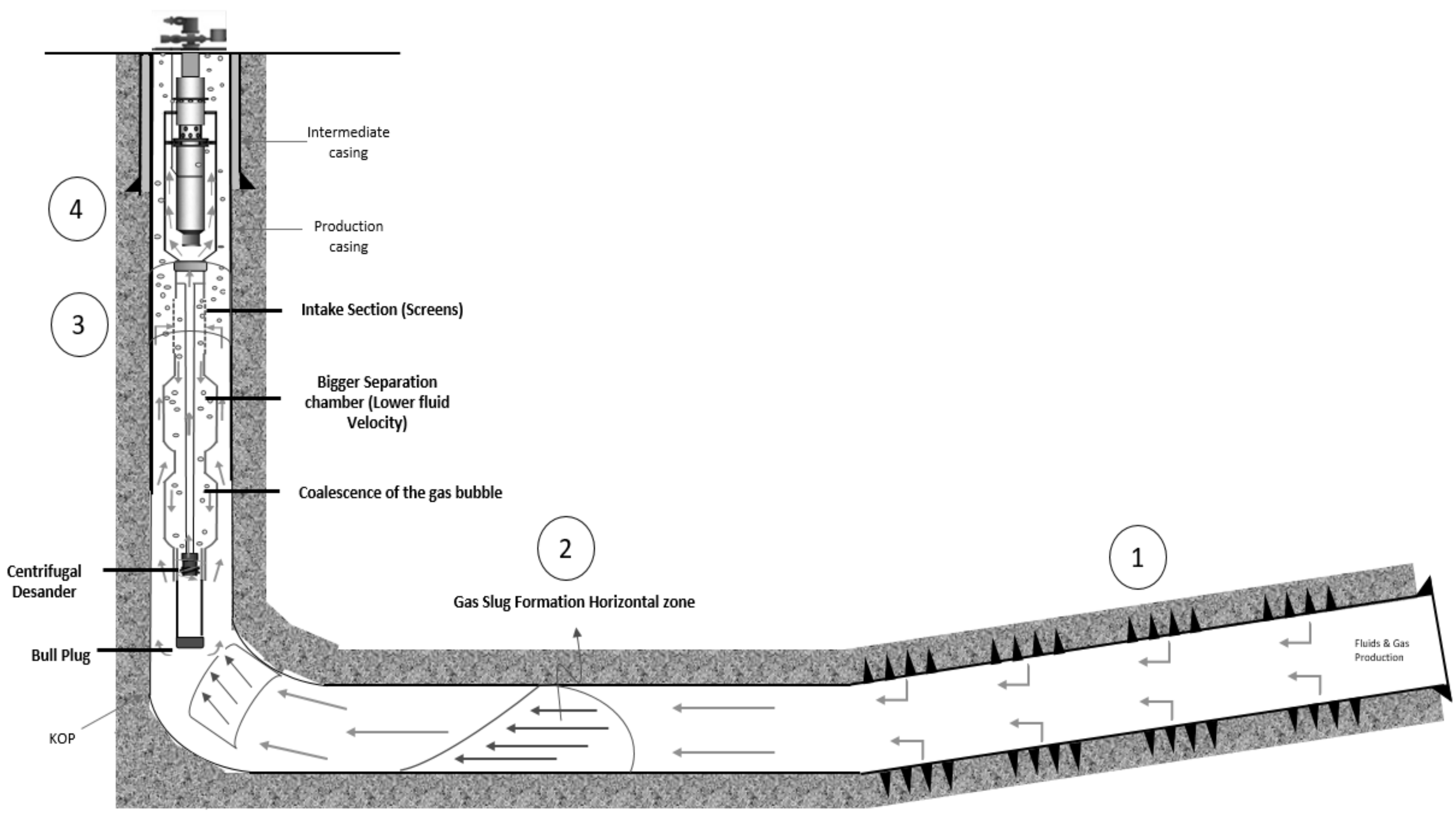


Figure 8. Breaking and separating Gas Slug with New Gas Separation Technology

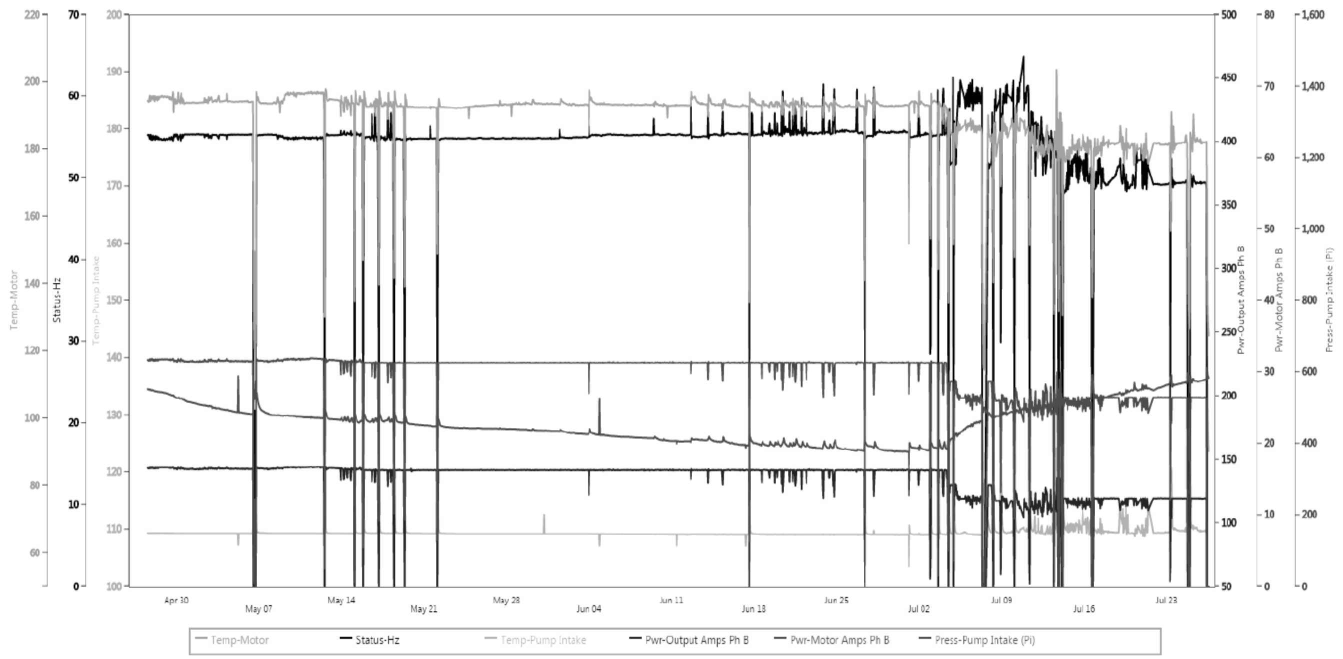


Figure 9. Well A Sensor parameters before New Gas Separation Technology

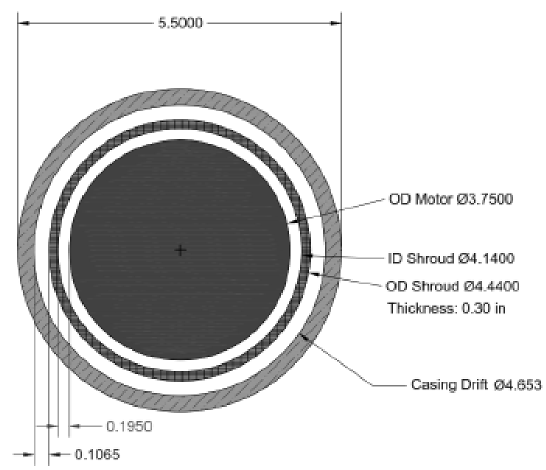


Figure 10. Well Configuration recommended for WELL A.

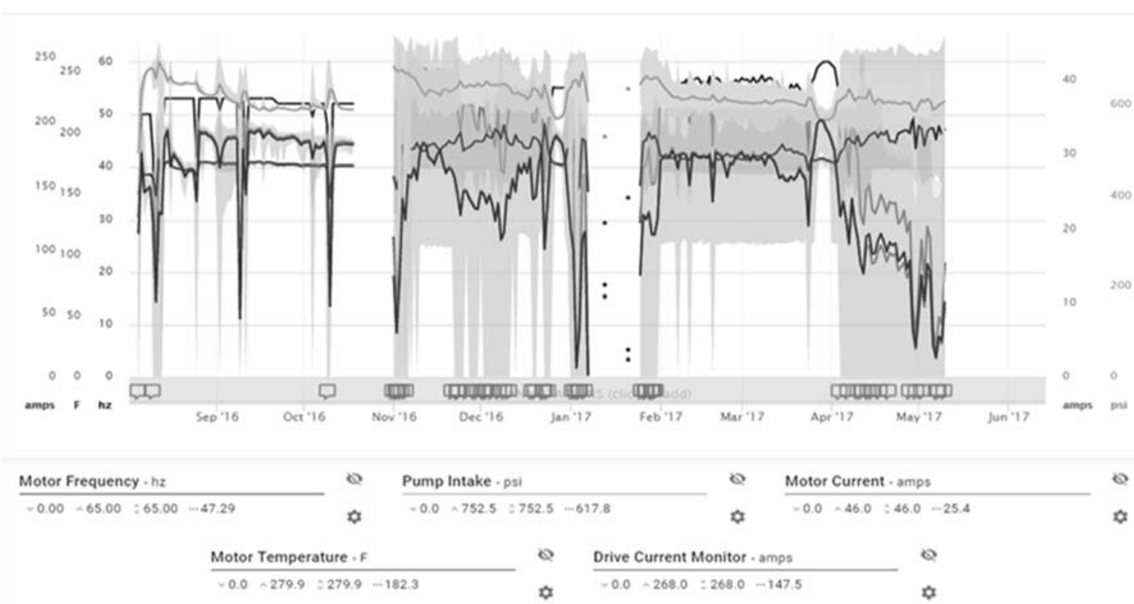


Figure 11. Well B Sensor parameters before New Gas Separation Technology

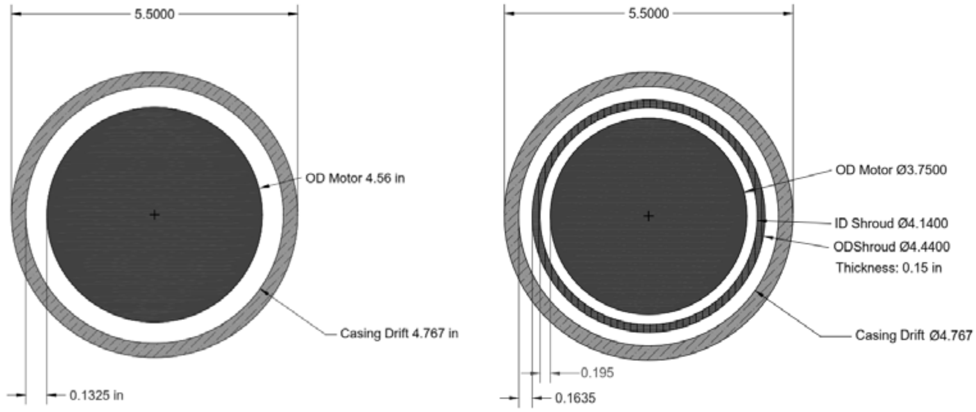


Figure 12. Well Configuration for WELL B Before and After the installation of The New Gas Separation

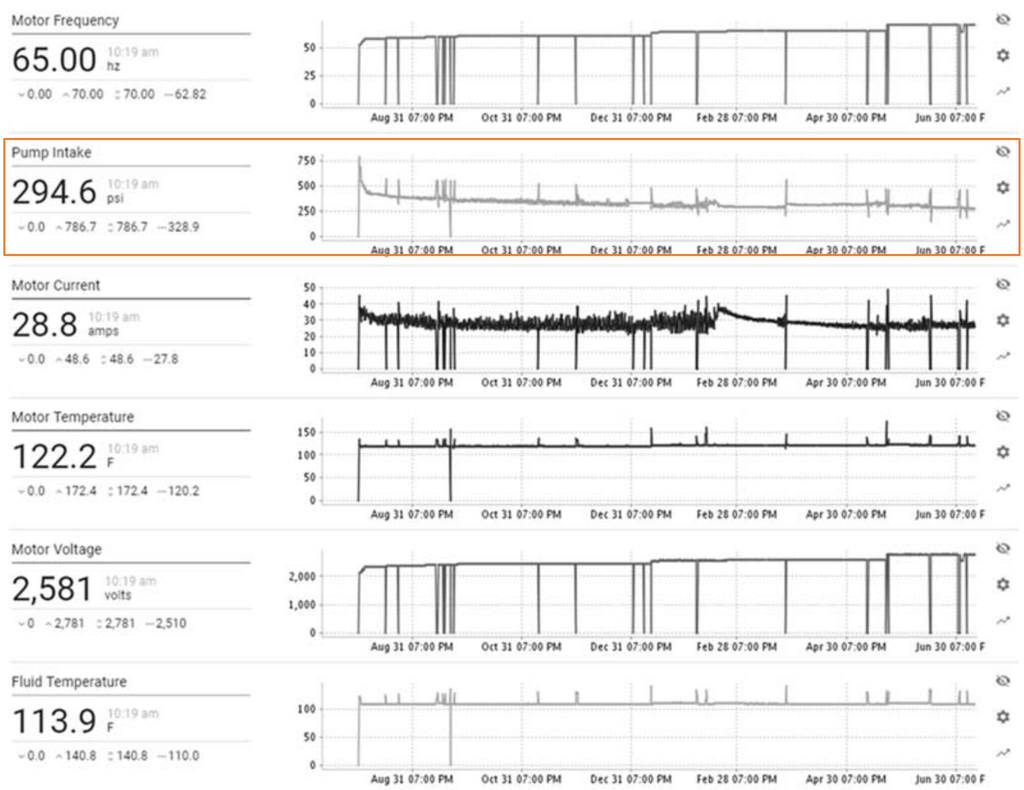


Figure 13. Well A sensor parameter AFTER New Gas Separation Technology was installed

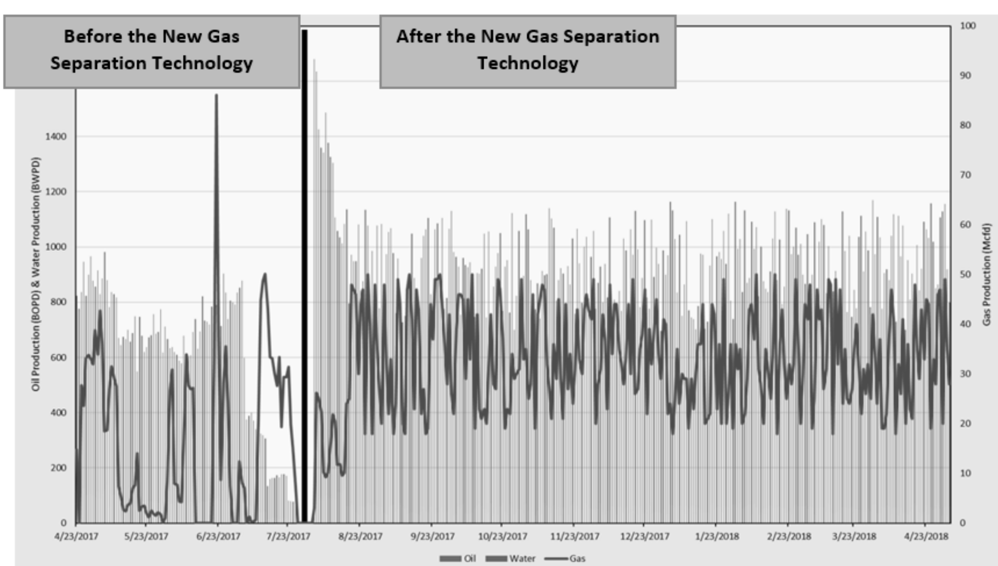


Figure 14. Production of Well A. Before and After the New Gas Separation Technology

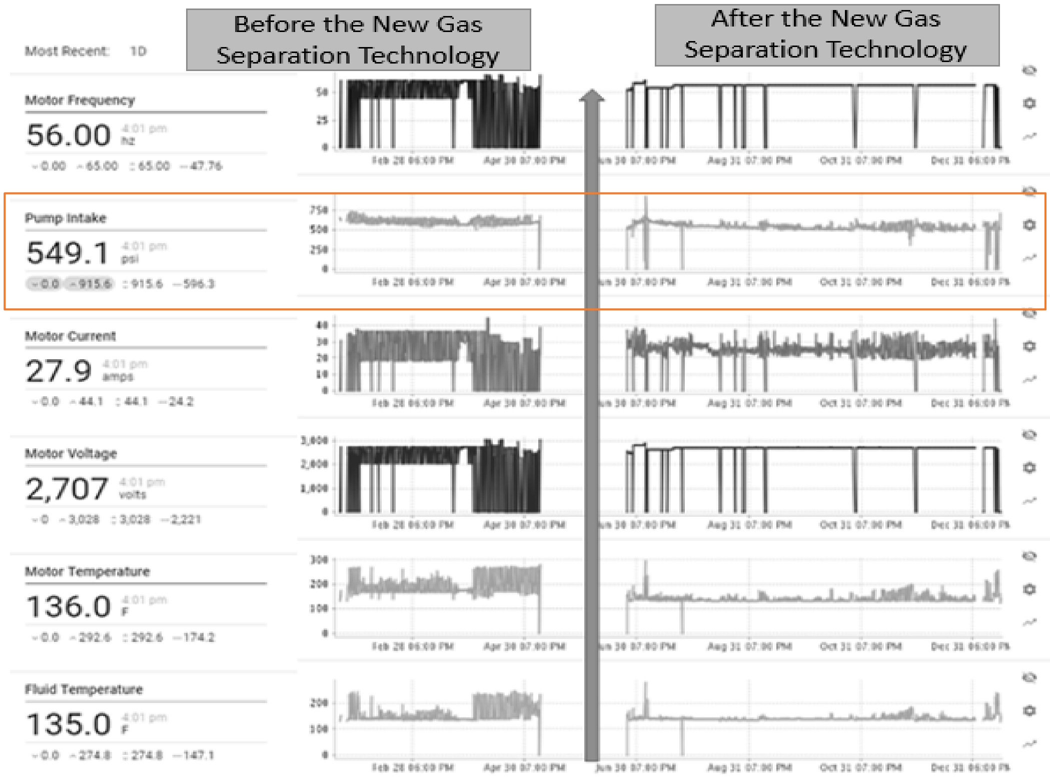


Figure 17. Well B sensor parameters BEFORE and AFTER New Gas Separation Technology was installed

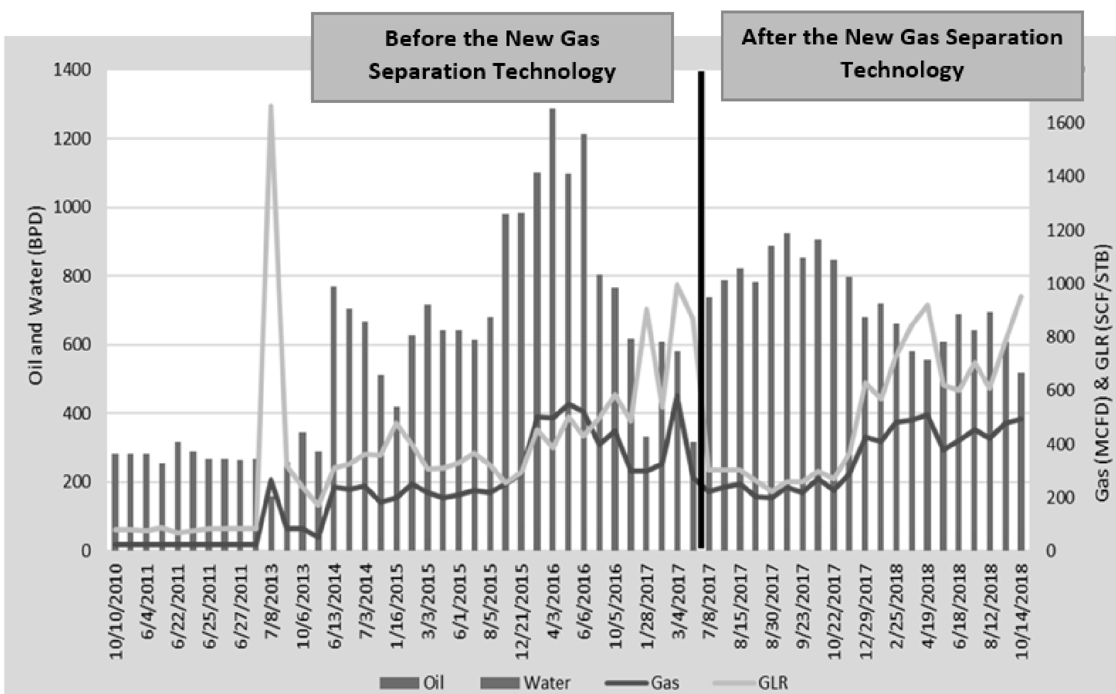


Figure 158. Well B sensor parameters BEFORE and AFTER New Gas Separation Technology was installed