Maximizando la producción en pozos gasíferos producidos por bombeo electrosumergible utilizando software inteligente de control de gas de variadores de velocidad: caso histórico en Colombia

Heidy Serrano
heidy.serrano@ecopetrol.com.co
Ecopetrol

Jesús Prada
_jesusantonio_prada@oxy.com_
OXY

John Chira
john.chira@bakerhughes.com

Alexandra Díaz
Alexandra.Diaz@bakerhughes.com

Camilo González
camilo.gonzalezartunduaga@bakerhughes.com

Bhorman Rodríguez
bhorman.rodriguezgiraldo@bakerhughes.com
Baker Hughes

Información del artículo: recibido: enero 2017-aceptado abril 2017

Resumen

Maximizar la producción en pozos de alto contenido de gas con levantamiento artificial, es uno de los más grandes desafíos que los operadores enfrentan diariamente. La acumulación de gas al interior de una bomba electrosumergible, (BES), genera una condición llamada “bloqueo por gas”, la cual previene la producción de fluido y conlleva a la detención del sistema. Múltiples paradas y eventos frecuentes de bloqueos por gas afectan el tiempo de vida de los sistemas de BES.

Se ha diseñado una solución pionera en la industria para resolver los problemas ocasionados por bloqueos por gas en sistemas BES: un variador de velocidad que incluye un software para control de gas que puede mitigar y despejar bloqueos por gas, manejar el draw down para minimizar los daños en la cara de la formación, y evita los bloqueos por gas durante periodos extendidos de producción de conglomerados de burbujas de gas a alta presión para mejorar la producción.

Este artículo presentará los resultados de la implementación del software de control de gas del variador de velocidad en un pozo de alto contenido de gas en Colombia. Este caso histórico presenta un pozo maduro con recobro secundario por inyección de agua.La operación del sistema BES fue monitoreada antes y después de la activación del software de control de gas. Los siguientes beneficios significativos en confiabilidad del sistema BES y en incremento de producción fueron obtenidos: incremento del 14% de producción diaria, operación estable, temperaturas de operación en fondo más bajas sin eventos de parada por alta temperatura de motor, una presión de admisión de la bomba más baja, (disminución de 170 PSI), y cero paradas del sistema debido a bloqueos por gas.

Palabras clave: Pozos gasíferos, bombeo electrosumergible, control de gas, variables inteligentes.

Maximizing production in gassy wells produced by electrical submersible pumping utilizing variable speed drive's intelligent gas control software: case history in Colombia

Abstract

Maximizing production in high gaswells produced with artificial lift systems is one of the greatest challenges operators face daily. The accumulation of gas inside an Electrical Submersible Pump (ESP) creates a condition called "gas locking", which prevents fluid production and leads to system shutdown. Multiple shutdowns and frequent Gas Locking negatively affect the runlife and profitability of ESP systems. However, the impacts of gas accumulation in ESP applications can be mitigated by implementing intelligent frequency control software included in Variable Speed Drives (VSD's) specifically designed to control and protect ESP's.

Has designed a first-to-industry intelligent solution to solve the problems caused by gas locking in ESP systems: a variable speed drive with built-in gas control software that can mitigate and clear gas locking, manage draw down to minimize formation face damage, and avoid gas locking during extended gas slugs to improve production.

This paper will present the results of the variable speed drive's gas control software implementation in a high gas well in Colombia. The case history presents a mature well with water injection secondary recovery. The ESP system operation was monitored before and after the VSD's gas control software activation. The following significant benefits in ESP reliability and increased production were achieved: 14% of daily production increase, stable operation, lower operating downhole temperatures with no high temperature events, lower pump intake pressure (decrease of 170 PSI) and zero system shutdowns due to gas locking.

Keywords: Gassy wells, submersible pumping, gas control, smart variables.

Introduction

Electrical submersible pumping (ESP) systems are a form of artificial lift developed, installed and operated to help operators companies to maximize production flow rates while reducing investment. This technology provides an effective and economical means of lifting fluids for different well and reservoir conditions. Operators are using more often ESP technology in their fields as flexibility of this technology has led them to produce almost all conditions including abrasives, high gas-oil-ratio, high temperature, viscous and higher depths. Furthermore, every year new advances are presented and tested in the field, to overcome those new production challenges that operators have to face to increase production and optimize operational costs. All these reasons motivate operators to increase year after year the share of ESP among other artificial lift technologies.

When approaching a high gas application, there are three different strategies that must be considered to select and size adequately the well completion and the ESP to produce the required flow rates expected by operators. These strategies are in accordance with a defined flow path of processes, such as avoiding, separating and handling free gas.

Avoiding is defined as performing all the necessary modifications in the well completion in order avoid the entrance of free gas into the pump intake, therefore avoidingfrom any harmful effects. Examples of this strategy are: setting the equipment below perforations andinstalling inverted shrouds, diptubes, gas avoiders or even reducing the flow rates. The second strategy refers to separating; this implies the use of a gas separator, a device used for expelling the low density fluid into the casing annulus after entering the ESP admission. Finally, the handling strategy refers to all those methods and procedures used to increase the ability of the pump to handle gas and to reduce all harmful effects when gas has already entered the pump. Several technologies for gas handling have been developed such as charge pumps, multiphase pumps and special operation control modes among others.

Although there is a great variety in technologies available in the market to improve ESP performance when high gas is present, some limitations are still present as some of them have their own restrictions and work on particular effects but they do not constitute a complete solution premium control technology has been developed to complete the gas handling portfolio, adding stability as an important component: allowing shutdown reduction and production maximization at variable operating conditions, such as those present in high gas applications. In addition, an invaluable resource has been added which let operators detect and react to gas lock conditions automatically, with no interventions at the well site. These features assure a higher production, higher runlife and a better and improved recovery in those reservoirs with dynamic changes, such as gas unconventional or high gas applications.

Occidental de Colombia in partnership with Ecopetrol have developed a test in a special well, informally called "the impossible well" in the field La Cira-Infantas, as it produces a very high amount of gas and all traditional resources available were not able to control production and gas effects. After 30 days of test, operational parameters improved significantly adding more production, better drawdown and fewer shutdowns to this well.

Overview of La Cira - Infantas field

La Cira-Infantas field is located in the Middle Magdalena Valley, near Barrancabermeja, Colombia, South America. It is one of the oldest oil producer fields in Colombia. **Figure 1** shows location of the field in Colombia. The Tropical Oil Company discovered the field with Infantas 2 well in December 1917. Then, production was initiated in 1918. Tropical Oil Company became an affiliate of the Standard Oil Company in 1919, and the concession reverted to the Colombian government in 1951.

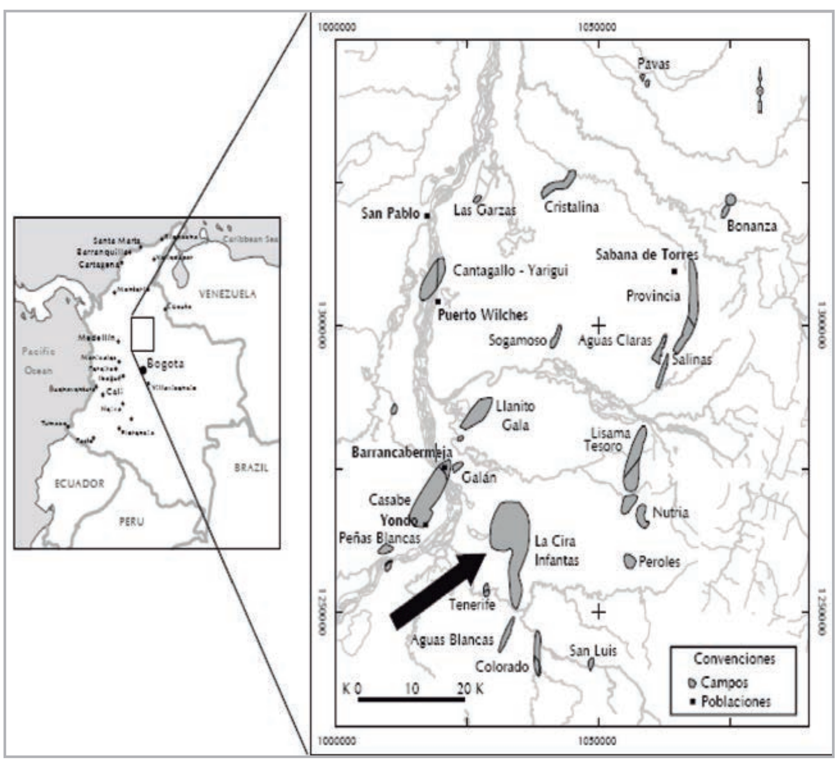

Figure 1. Localization of field Cira-Infantas.

Initially, most of the wells production was achieved by natural flow, and then artificial lift methods were implemented, starting with Gas Lift and later using beam pumps. Field production reached about 65,000 BOPD in 1940; however, current production has declined to approximately 39,000 BOPD. A water injection project was initiated in 1957 in order to recover reservoir pressure and enhance oil recovery. The waterflood showed a favorable response, and the project was successfully expanded to other areas of the field.

Ecopetrol and occidental agreed to pursue a phased approach in the partnership. The partnership started in 2005.

From a structural point of view, La Cira-Infantas is composed of two structures: in theNorth, which is an anticline called the Cira, and in the South, called the Infantas. As an important feature, the Infantas structure is structurally higher than the Cira structure. La Cira-Infantas field produces from A (Colorado), B and C sands (Mugrosa). Approximately 90% of the production and reserves are associated with C sands. Reservoir pressure has been estimated to be about 1450 psi at a datum of 3,300 ft. The API gravity of the oil produced range from 27.9 at Infantas to 21.4 at La Cira. The initial GOR in the field was estimated to be 150 SCF/STB. The most important issue to remark is that the reservoir pressures have decreased to around 200 psi in some areas.

Currently, La Cira-Infantas field has around 1900 wells which count for all different well trajectories and well purposes, such as deviated producers, vertical producers, deviated injectors and vertical injectors. This field produces nowadays from C sand (mugrosa formation), which consists of 400 to 500 feet of section about 50% sand.

The artificial lift systems used currently are the beam pump and PCP in number of wells. However, more ESPs have been used in the last years in order to increase production according to expectations and overcome new restrictions, such as gas production and high deviated wells where conventional systems have demonstrated to have limitations, has installed more than 150 ESP have been installed since 2009.

Effects of gas in applications with ESP

The purpose of the ESP is to lift and produce the fluid to surface at the required flow rate by the operator. Some limiting factors are the available space downhole in the well and the fluid properties when evaluating wells with high gas-oil ratio; these two factors need to be handled by the technology installed downhole. However, the presence of free or dissolved gas in the column is not necessarily a negative concern: gas lightens the fluid gradient (density of the mixture) in the tubing and therefore reduces the pump load with an effect equivalent to a gas lift; in other words, more gas into the fluid requires less discharge pressure to be generated by the pump. The real challenge when operating with ESP in high has-oil ratio is, moving the gas from the annular space to the tubing through the pump with any harmful effect.

In centrifugal pumps, multiphase fluids do not remain homogenous due to the difference of density between the liquid and gas phase, segregating them very quickly and generating several challenges that need to be handled by the pump, such assignificant performance degradation.

1. When the fluid has more gas, the total volume of fluid handled by the pump, might increase dramatically and the lift produced by each stage will be reduced significantly according the pump curve. As a result, production at the surface might be affected. This effect is considered with a suitable selection and sizing.

2. When some gas bubbles segregate from the fluid, tend to group on the lowpressure side of the impeller. This gas pocket might interfere with the flow, leading to a reduced production at surface. **Figure 2** shows this condition is usually called "gas blocking". At this point, there is still production and different procedures to follow. If the effect worsens, a gas lock occurs.

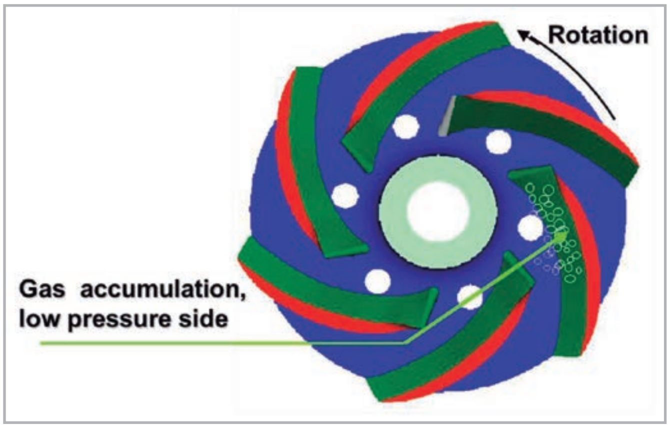

Figure 2. Gas accumulation in the low pressure side.

3. As gas accumulates in the low-pressure side, it might completely block the flow path in the vanes, avoiding any fluid moving through it. This point is called "Gas Locking". **Figure 3** shows this situation.

A secondary effect, called "surging" might be present. As the liquid production decreases, gas separation improves and higher pressures help recover lost performance and production, and the overall process starts again with accumulation of gas up to get a new gas locking, both processes repeat cyclically bringing in some important consequences to consider:

a. Loss of production at surface

b. The pump rotates without flow, generating a temperature increase in the motor, seal section, pump, motor lead and power cable as heat transfer from the ESP is eliminated. This might lead to a reduced runlife according to the Arrhenius life-stress model.

c. Loss of lubrication in the system components as dielectric oil, might have a lower temperature rating.

d. Crystallization of polymers if high temperature exceeds ratings.

e. Thermal cycling might deteriorate insulation and lead to failures.

f. Changes in tolerances and major wear.

Under this context, it is imperative to size, select and operate all ESP equipment avoiding the harsh effects of gas into pumps, as longer runlife and better performance is expected. Portfolios for avoiding, separating and handling gas must be mixed and used to get maximum performance in high gas-oil-ratios.

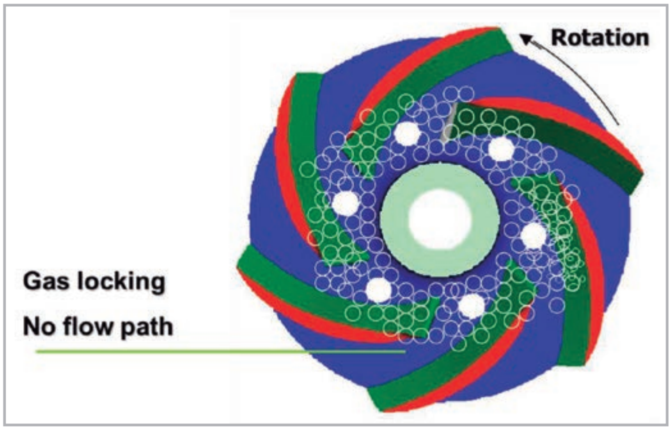

Figure 3. Excessive accumulation of gas in the impeller generating a gas lock.

Control modes and MaxRate™

Variable speed drives, used currently in the oil and gas industry, have different options to control ESP according the application and target of operation: There are mainly two control modes: Frequency mode and PID mode. When operating in Frequency mode, the controller will attempt to operate at the user programmed frequency with any feedback; it means that other operational parameters might be changing with no control. When operating in PID mode, the controller will attempt to vary its output frequency in order to maintain a given feedback (for example PIP or current). The setpoint of PIP or Current, dictates which control value or input signal will be used as the target that the controller will attempt to reach and maintain.

When operating in high gas applications, the PID mode is often used to compensate the harsh effects of gas. A PID mode with PIP feedback might limit the amount of free gas inside the stages of the pump, as free gas is a direct result of operational pressure. Furthermore, when operating in a PID mode with current feedback, motor load will decrease as more free gas is handled and the output frequency will rise until frequency limit parameters are reached. The slight increase in frequency will further compress the gas and help to move it out of the pump.

A third operation mode has been introduced which is an intelligent and dynamic solution, designed to reduce all the harmful effects of high gas applications when operating an ESP system, while improving production and drawdown of the reservoir. This intelligent solution has been developed and consists of a software package to be installed in the variable speed drives. This software has two levels or modes of operation:

a. Gas control which adjusts the frequency of operation in the VSD automatically, in order to mitigate gas locking and pump shut down by running a sequence of steps according to the torque of the system, while optimizing production and allowing the operator to achieve maximum production. The GasControl functionality is based on a Hybrid PID control with two components: controlling drive output frequency using a PID control loop based on output amps, with the system trying to maintain a constant output current as demanded. This control loop reacts relatively quickly to changes in output current resulting from load changes due to potentially gas events. Also, a secondary control loop that attempts to monitor down-hole pressure at a much slower rate, and adjust the demand of the amps control loop to ultimately get the well down to the desired intake pressure level.

b. Gas purge which automatically makes multiples attempts to break the gas lock or pump shut down when these events occur. If the system determines the equipment is still locked after a defined number of attempts, the ESP will shut down to prevent any damage.

The software's algorithm is designedto sense a drop-in torque on the ESP system,indicating any gas lock event. This softwarethen,automatically, resets the VSD to slowthe ESP system down, to the point that fluidis no longer being produced to the surface when a back flow through the pump begins, and 'flushes' the gas bubbles from behind the impeller vanes. Once the gas lock is cleared, the VSD will speed up to previous frequency to reestablish pumping. The software also contains logic to manage draw down in challenging situations, such as horizontally completed wells and long duration gas slugging. By using this novel approach to downhole pressure targets and control loops, operators can automatically manage fluid levels and bottomhole pressure. This allows the well to produce longer, increasing ESP system up time and reliability.

Implementation procedure

The software implementation begins with the previous study of the behavior of the well with presence of gas in the ESP. During a gas lock event, the pump load decreases as indicated by the reduction of current and torque. This is caused by the accumulation of gas inside the pump. In this case, the pump is not able to lift fluid efficiently, the pump intake pressure, (PIP) increases and the motor temperature rises as the flow past the motor is virtually zero. This condition is seen at a stable operating frequency. Before the implementation of the software it is necessary to recognize and register the operational limits of current, PIP and motor temperature that indicate a possible gas lock. These values will be used to program the software.

An implementation protocol was created to identify the operational limits in each application:

1. Start with the frequency mode and operate at the frequency where the well is stable; gradually increase frequency per hour without exceeding the maximum operating frequency of the system. This maximum operational frequency is defined by the operational conditions of each application, and design limits such as flow level over pump, gas locking, mechanical loads and operating temperature limits permissible for the ESP system.

2. Operation in PID control mode with current as feedback, the setpoint value for this control will be the current value where the well begins to show gas interference when operating in manual frequency mode.

3. Activate the software using a target PIP andcurrent found in the previous stage, (PID control mode).

In order to ease and track all changes in the settings of the advantage variable speed drive and the software, remote monitoring services are used. This web platform let the engineers to communicate with the VSD and make all changes and calibrations remotely, with no need to be in well site. In addition, monitoring provides real time trends where operational parameters might be analyzed and new calibration decision might be taken. In this process, 24/7 monitoring team, applications engineer and surface controls engineer take actions to plan, execute, review and feedback the calibration process.

The test started in frequency control mode. Frequency was increased to a level where the system experienced symptoms of gas locking. Afterwards, it was decided to activate the next mode operation, PID control mode. It was observed that at 72 amps the system started to evidence gas issues.

The PID control mode started with a target current of 69 amps for achieving a PIP of approximately 450 PSI, but the well showed unstable conditions with oscillations between 60 Amp and 95 Amp. It should be noted that the current oscillation is directly related to gas interference within the ESP equipment. This current variation caused several shutdowns due to gas locking. Because of the highly unstable conditions of the system, on June 4th 2015, it was decided to start the software based on the previous data obtained with PID control mode.

Although the implementation with the frequency mode is possible, the limitations found were a clear indicator of the need to implement to an intelligent software package to control the gas in the well.

The values in the PID control mode were set in 70 Amperes and PIP in the control loop pressure in 620 PSI. After starting the control operation by means a the software, an immediate reduction in the oscillation of the intake pressure and in the frequency of stops because of gas blocking events was observed. However the purge module was also activated to remove the gas accumulated in the pump. This module was activated with a current setpoint of 71 Amperes; this value was adjusted during calibration with a final value of 69 Amperes. **Figure 4** shows the behavior of the well during the operation in frequency and PID mode.

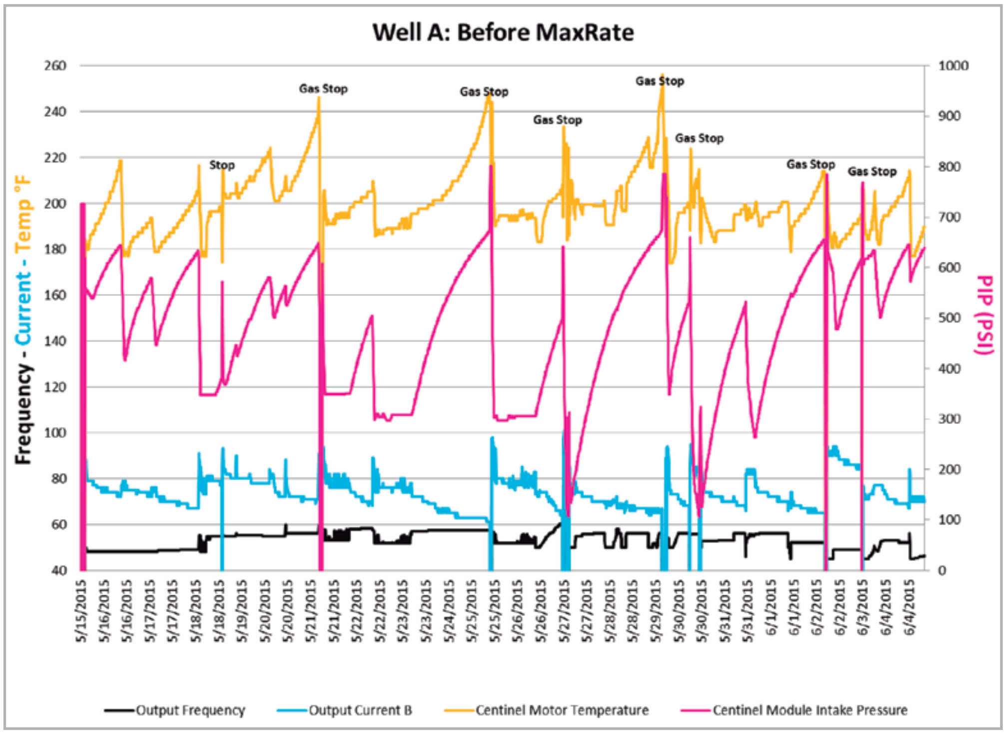

Figure 4. Operational trending in mode PID and frequency.

During the calibration procedure with the software some modifications were made to the parameters of maximum and minimum frequency, current setpoint and PIP, conjugated with the PID mode. The objective was to find out the stabilization point of the gas in the well through control software. For this reason, the software started with a setpoint of 620 psi of PIP and current of 70 Amp. The adjustments to proportional, integral and derivative gains were made gradually until stabilizing the well in a desired PIP.

On June 5th, some adjustments were performed to PIP setpoint gradually, adjusting a reduction to reach the PIP setpoint of 450 PSI also adjusting the maximum frequency to 52 Hz. However, an erratic behavior of the current was observed and fluid lifting loss, indicated by the increase in PIP of over 600 PSI. On June 8th, a new change was made in the pressure setpoint adjusting the value to 350 PSI with the same conditions in the current and the maximum frequency set points. The range of frequency was expanded to 2 Hz with respect to the maximum setpoint frequency.

After implementing these changes, the well began to show a decrease in PIP with oscillations between 400 PSI and 250 PSI. During the next day, additional adjustments were performed on the frequency range, in order to maintain the PIP close to 250 PSI, which is the new PIP setpoint from the day June 20, 2015. **Figure 5** shows the behavior of the different variables during the calibration procedure with the software.

Once the well parameters oscillate around 250 PSI, the gains were increased to improve the speed of the response of the algorithm to dynamic changes of the well. With these settings the well PIP stabilized around 250 PSI.

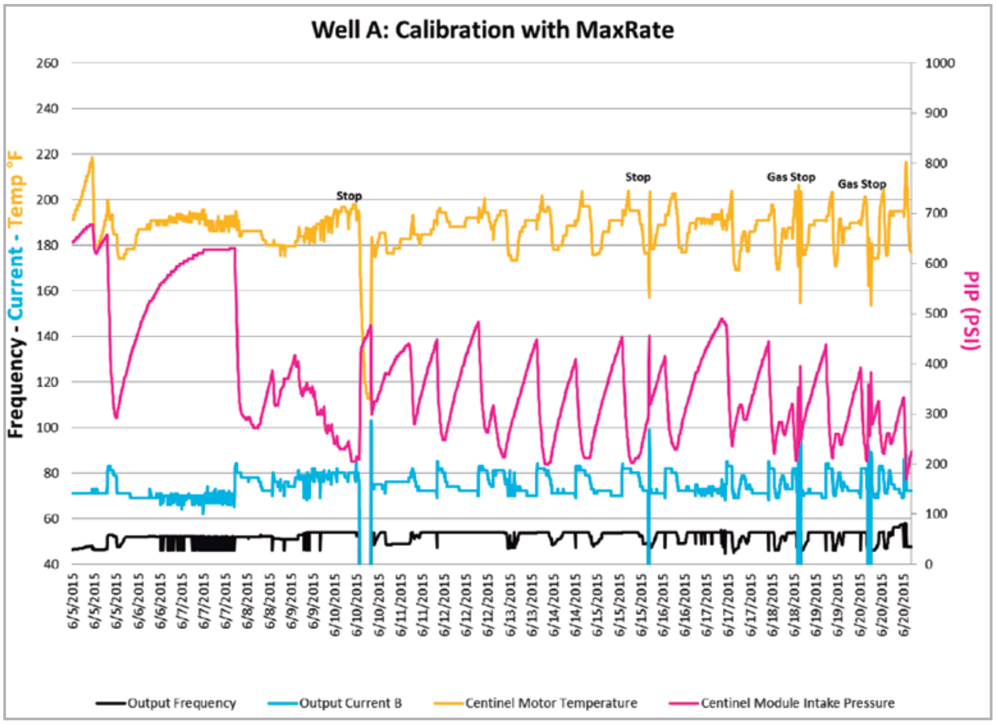

Figure 5. Operational trending whilecalibration.

Results

When the well was stabilized around 250 PSI, this operational point was considered as the optimal setting for system operation under the software mode. Initial interpretations considered that the pressure where ESP presented gas locking was close to 150 psi; however, it was found that it actually was close to 300 PSI in real measured well conditions.

The well was monitored for 45 days after finding the equilibrium variables to avoid gas locking by independent action of the software on the well. **Figure 6** shows the behavior of the well during these 45 days, some potential gas blocking events are observed, which were correctly mitigated with the intelligent software package, and only one (1) stop due to field power supply failure.

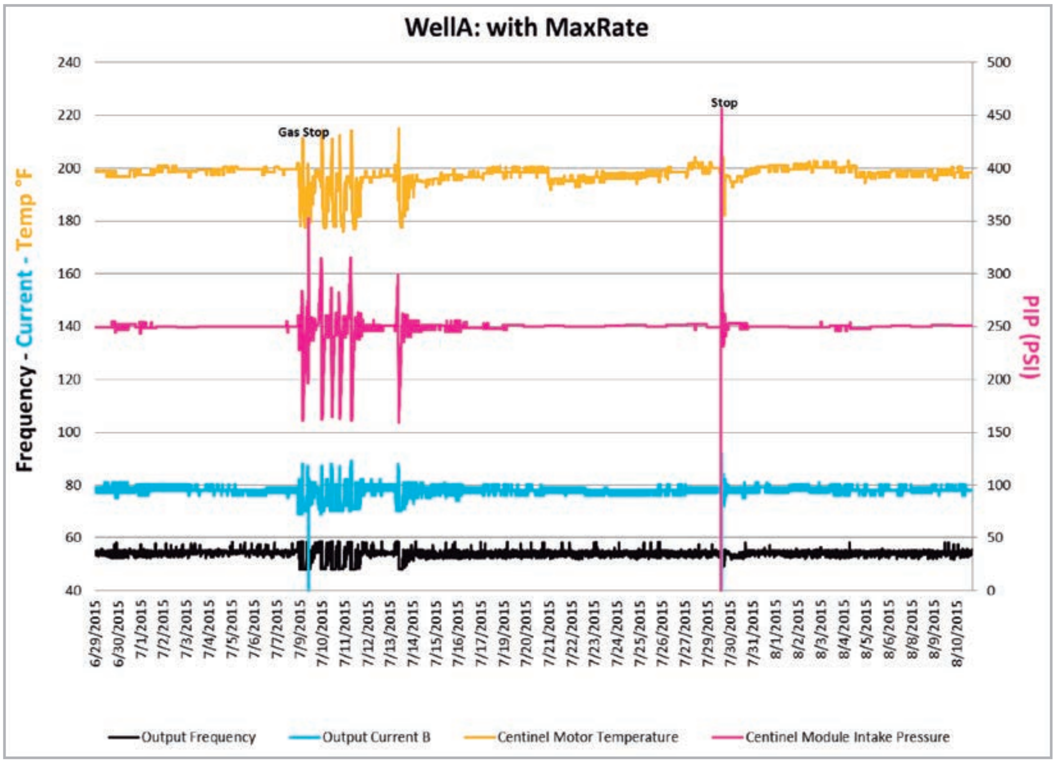

Figure 6. Operational trending whilesoftware implementation.

It is very remarkable how the software managed the ESP and the operational parameters of the well. After success the successful calibration process was obtained, a constant pump intake pressure (PIP) of 250 psi was observed, avoiding those cyclical pressure changes generated by constant gas locking in this well, while improving pump performance, production and operating temperature. As PIP is less after implementation, more stable production was obtained.

Also, the gas purge mode controlled five events of possible gas locking, by maintaining the ESP running, **Figure 7** shows the automatic change of frequency when the current is descending and the PIP is increasing due to gas in the pump. The frequency stays in the lower frequency value while the free gas is removed; after purge of gas is satisfactory, the software increases again the frequency to the value where the well is stabilized.

In all of these 5 events, no personnel were required on the well site in order to take actions on the ESP or VSD, to execute manual procedures to eliminate gas locking. As a result, faster response was obtained increasing production and avoiding gas locking shutdowns.

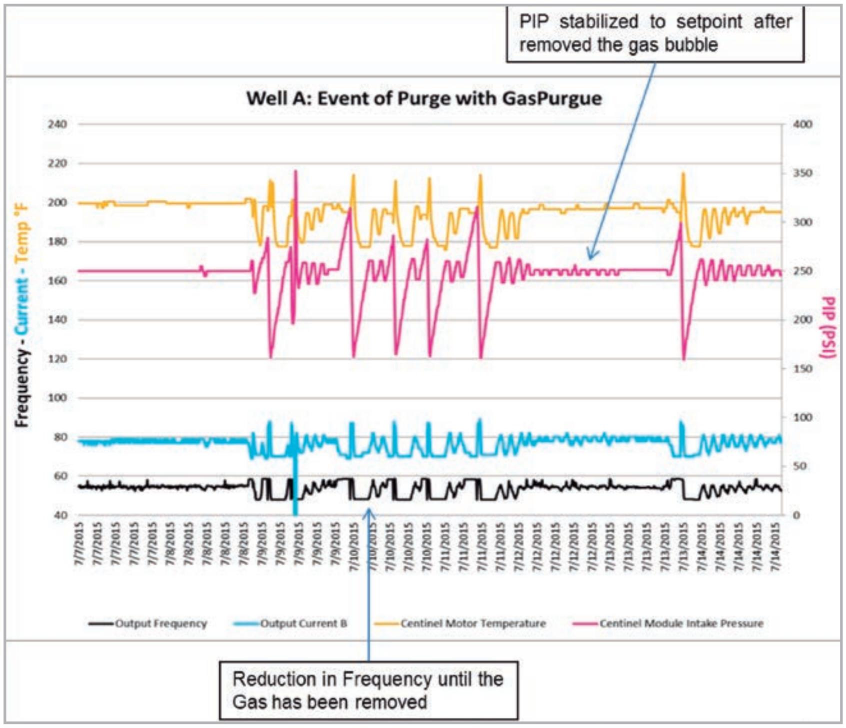

Figure 7. Operational trending while the software was supervising the pump operation. In all of these 5 events, no personnel were required on the well site in order to take actions on the ESP or VSD, to execute manual procedures to eliminate gas locking. As a result, faster response was obtained increasing production and avoiding gas locking shutdowns.

Conclusions

The implementation of a pump gas control software management in a well of La Cira – Infantas, allowed an increase in daily fluid production of almost 14 %, to reach a daily average production value in the well of 74 BFPD. In addition, downtime or deferred production hours due to gas locking were eliminated with the function of the gas control and gaspurge modules which are part of the software. In total, during the first four months of implementation of the software, an incremental oil production of 666 barrels of oil was achieved representing around $29,000.

Moreover, the software offered a premium solution for increasing the reliability of the downhole ESP system, which was protect it from irregular conditions of operation in the well caused by gas blocking, such as low load on the pump and high motor temperature. The elimination of these two conditions increased lead to increase runlife by reducing the mechanical and electrical stresses to the ESP system.

These results demonstrate the importance of having an integrated ESP system including surface, cable and downhole equipment, working simultaneously to achieve the production goals and the desired profitability of the wells. It is vital to establish the correct production requirements according to the reservoir data and the operating conditions in order to have a variable speed drive which could properly fit demanding applications.

Acknowledgements

The authors of this paper would like to extend appreciation to Ecopetrol and OXY employees and all production team for their technical support during the development of this test; to Baker Hughes Colombia Artificial Lift Manager, Andrés González, for his review and valuable input to this paper; to Baker Hughes Colombia Field Service Team for their technical support, as well as their constant and unwavering commitment to customer service; all Baker Hughes Controls team for their enormous help and support during the implementation of this new technology in our Ecopetrol and Occidental operations; and to Nicolas Sarkis, Fernando Quijano, Cristian Von Zedtwitz, Grant Stewart, Noel Atzmiller, Thierry Jacquart, Baker Hughes employees who helped with priceless feedback, comments and advices during this document elaboration.

References

- BAKER HUGHES. 2009. *Electrical Submersible Pumping Systems Gas Handling Guideline.*

- BAKER HUGHES. 2013. Electrospeed Advantage Variable Speed Drive.

- CENTRILIFT. 2009. *Submersible Pump Handbook*, ninth edition. Claremore, Oklahoma: CENTRILIFT.

- Prieto, M., Mantilla, J., Owens, B. K. et al. 2009. *Redevelopment Progress for Colombia's La Cira-Infantas Field.* Artículo presentado en la SPE Latin American and Caribbean Petroleum Engineering, Cartagena de Indias, Colombia, mayo 31 - junio 3. SPE-120794-MS. https://doi.org/10.2118/120794-MS.

- Takács, G. 2009. *Electrical Submersible Pump Manual: Design, Operations, and Maintenance*. Burlington, Massachusetts: Gulf Professional Publishing.

Semblanza de los autores

Heidy Serrano

Ingeniera de Petróleos con 13 años de experiencia en la industria de petróleo y gas. Inició su carrera trabajando en well testing. Actualmente labora en Ecopetrol como Ingeniera de producción para diferentes sistemas de levantamiento artificial en el Campo La Cira–Infantas.

Jesús Prada

Ingeniero Mecánico con 28 años de experiencia en la industria de petróleo y gas. Inició su carrera trabajando para Halliburton en bombeo y well testing. Luego, comenzó a trabajar para Schlumberger en levantamiento artificial. Actualmente trabaja en OXY como consultor de tecnologías de bombeo electrosumergible para el Campo La Cira-Infantas.

Jhon Chira

Ingeniero de Petróleos con 16 años de experiencia en la industria de petróleo y gas. Ha trabajado los últimos doce años en levantamiento artificial. Inició su carrera como asistente de company man en Perú. Posteriormente, trabajó cuatro años como Ingeniero de campo y dos años como Ingeniero de aplicaciones para Pluspetrol en Perú. Actualmente trabaja como Ingeniero de aplicaciones y ventas para Baker Hughes en el Campo La Cira-Infantas.

Alexandra Díaz

Ingeniera Electricista con seis años de experiencia en la industria de petróleo y gas. Inició su carrera como Ingeniera de soporte técnico para sistemas de control de bombas de levantamiento artificial, siendo responsable de la implementación y optimización de variadores de velocidad para requerimientos específicos de control, protecciones y eficiencia energética.

Actualmente trabaja como Ingeniera de aplicaciones y ventas para Baker Hughes, desarrollando proyectos para optimizar los sistemas de levantamiento artificial en campos de crudo extra pesado.

Camilo González

Ingeniero Mecánico con siete años de experiencia en la industria de petróleo y gas. Inició su carrera como Ingeniero de aplicaciones, siendo responsable de la correcta selección y dimensionamiento de sistemas BES en diversos campos. Actualmente lidera el grupo de ingeniería y aplicaciones de Baker Hughes, en donde diferentes proyectos de levantamiento artificial son planeados, desarrollados y analizados con el objetivo de mejorar la confiabilidad, producción y optimización energética de los sistemas bombeo artificial de acuerdo con las necesidades de los campos.

Bhorman Rodríguez

Ingeniero Electrónico con tres años de experiencia en la industria de petróleo y gas. Especialista en instrumentación y SCADA.

Inició su carrera en Baker Hughes como Especialista de operaciones de campo para levantamiento artificial. Actualmente trabaja como Ingeniero de soporte técnico para sistemas de control de bombeo artificial en Baker Hughes, desarrollando diversos proyectos para variadores de velocidad e instrumentación.