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IMPROVING WELL PERFORMANCE WITH MULTIPHASE HELICOAXIAL PUMP IN WELLS WITH HIGH GAS-TO-LIQUID RATIO

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Abstract

As the number of mature reservoirs continues to increase worldwide, so has the development of new technologies to aid electrical submersible pump (ESP) performance. Because depleting fields produce increasing gas volume, gas separators and gas handlers are necessary to maintain pump performance and production. In wells with high gas volume, production is limited by the centrifugal pump's ability to handle gas. Centrifugal pumps suffer from head degradation and gas locking in the presence of high percentages of free gas. Different technologies have been implemented to help operators achieve their production goals. However, as downhole conditions continue to change, the gas-handling capability of the technology installed becomes insufficient, resulting in downtime due to gas lock, limited drawdown, high operational costs, high motor current fluctuations, and other issues. A multiphase helicoaxial pump installed below the main production pump allows the production pump to efficiently handle higher percentages of free gas and up to 75% of gas volume fraction (GVF) at the first stage. This system is designed to improve stability in gassy wells, provide better slug handling in horizontal wells, increase the production rate and recovered reserves, and increase ESP effectiveness.

To enhance production in oil wells experiencing gas-locking problems, an operator began optimizing downhole ESPs where they showed unstable operational behavior and where the GVF was overcoming the maximum gas-handling capability of centrifugal pumps (up to 45% GVF). In the first optimized ESP wells, the operator was able to increase production by reducing gas-locking production shutdowns, to stabilize motor current fluctuations, and to increase production and reservoir life by increasing drawdown and allowing effective pump operation at lower intake pressure. By the end of 2010, a total of 10 wells were operating with this technology within three different fields. Currently, more than 25 wells have been optimized. The implementation of this technology in wells with high gas/liquid ratio has been demonstrated to be an effective solution. It has also allowed the operator to expand the use of the ESPs in gassy wells, previously thought to be unsuitable for ESP application.

Introduction

When production starts in a field, the reservoir pressures of the field begin to decrease and drop below the bubblepoint, resulting in secondary gas caps. Consequently, the producing gas/liquid ratio (GLR) and gas volume fractions (GVF) of the wells increase. The wells considered in this analysis are in the El Portón and Volcan Auca Mahuida fields in the Neuquén basin, Argentina. The wells in both fields are mainly produced using electrical submersible pumps (ESPs) (gas lift as an artificial lift method is also used, but only in El Portón field). However, for the ESPs, the drawdown has been limited by traditional ESP gas-handling technology which typically cannot handle GVFs higher than 40%. Based on this limitation and the downtime generated by the constant gas locks, a local operator decided to proceed with the installation of an advanced helicoaxial pump technology in wells in these fields as a technological solution to the free gas issue.

Head Degradation Due to Gas Production in Centrifugal and Helicoaxial Pumps

Traditional centrifugal pumps (i.e., nonaxial and nonhelicoaxial stages) generate less head in high-GVF fluids, which can ultimately lead to gas locking. The main reason why these pumps generate less head is phase segregation in the impeller flow path. In a centrifugal pump, the centrifugal and Coriolis forces induce phase separation because of the difference in body forces acting on the bubbles of free gas and liquid resulting from the difference in density. The free gas then accumulates in the low-pressure zone of the impeller. As a result, work transfer from the impeller to the fluid is impaired, which practically means that there is head loss relative to the impeller curve. In extreme cases, a large accumulation of gas at the impeller inlet leads to gas locking **(Fig. 1).**

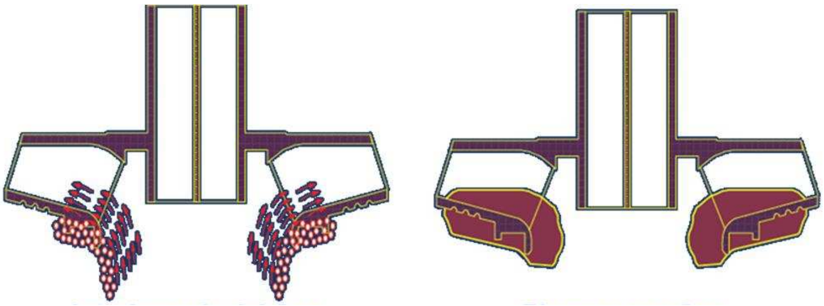

Fig. 1—Gas interference and gas lock on impeller.

If radial centrifugal and Coriolis forces can be reduced, then, based on the preceding explanation of the behavior of radial and mixed flow impellers **(Fig. 2)** in gaseous media, phase separation and the associated head degradation can also be reduced. It is importante to add that radial flow stages are capable of handling 10% of free gas while mixed flow stages up to 20%. Axial flow impellers **(Fig. 3)** have improved performance in the presence of free gas because centrifugal and Coriolis accelerations have opposing components and also because secondary flows contribute to better phase mixing. The helicoaxial impeller goes one step further, and, according to Gulich (2010, Chapter 13.2),"a helicoaxial impeller can be viewed as an axial impeller with a conical hub and, as a result, can handle any GVF" because, in addition to the axial impeller features, there is cross-channel mixing induced by the shape of the hub and secondary flows. Essentially, the shape of the impeller reduces phase separation. In addition, the helicoaxial stage accelerates the fluid (both phases), which mitigates gas accumulation at the eye of the first impeller of the ESP and prevents possible gas locking. What the helicoaxial stage does not do is generate enough pressure to reduce the GVF before the fluid enters the main pump. The free gas is, therefore, still present in the main ESP.

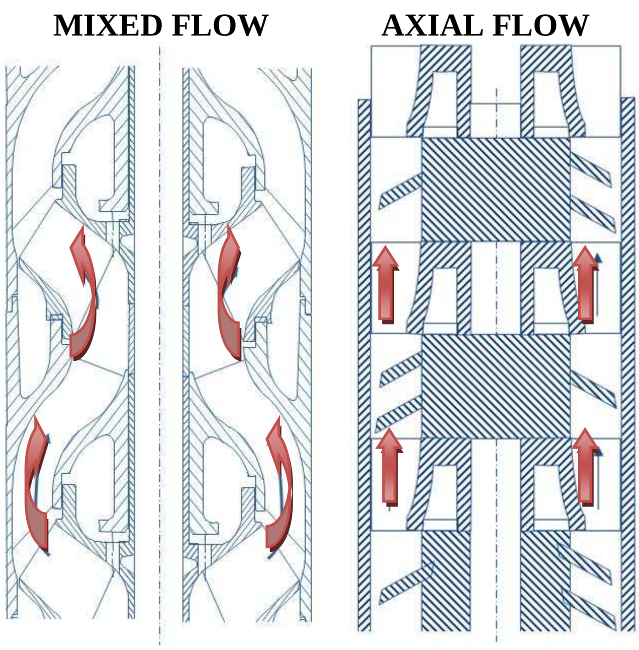

Fig. 2—Comparison of mixed-flow and helicoaxial impeller flow paths.

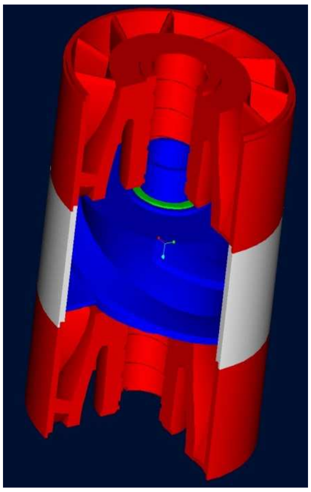

Fig. 3—Axial flow impeller in multiphase helicoaxial pump stage, cutaway view.

Phase separation and gas accumulation are not the only causes for the poor gas-handling capability of standard ESPs. The other issue is the negative pressure gradient caused by the Coriolis force that induces reverse flow, which explains why the advanced gas handler (AGH) is built using impellers with mixed flow (i.e., similar to a standard ESP that has lower gas-handling capabilities when compared to a helicoaxial booster pump). The AGH stages are fitted with recirculation ports in the impeller which allow liquid to reenter the flow passage in a low-pressure area and thereby entrain accumulated gas and transport it to the next stage, which is the feature that provides the enhanced gas-handling properties. As the AGH has mixed flow impeller geometry, the Coriolis and radial forces are in the same direction; therefore, these body forces combine to separate the two phases of gas and liquid as with standard ESP stages, and thus gas accumulates at the inlet. Despite the reentry liquid assisting its transport to the next stage, the gas still must overcome the negative pressure gradient in the stage caused by the Coriolis force. There is, therefore, a GVF limit at which point the liquid cannot entrain the gas and overcome the negative pressure gradient. For the AGH, this limit is approximately 40% GVF (Castro et al. 1996). The helicoaxial stage, on the other hand, does not have a negative pressure gradient because the Coriolis and radial forces oppose each other; therefore, the phase separation is not aggravated by the impeller. As a result, an ESP equipped with a helicoaxial booster pump can handle GVF of 75% in steady state without gas locking and up to 100% in transient conditions such as gas slugs. Both the AGH and the helicoaxial booster pumps operate in the same way—they impart energy, which consists of momentum (i.e., ½ m V2 type energy). These pumps do not provide any substantial GVF reduction as the differential pressure they generate in downhole pumps is relatively small. It is the reverse-flow characteristic (pressure gradient) of the impeller upstream of the main pump which gives the main pumps its ability to handle higher GVFs. The combination of the reverse-flow characteristic and kinetic energy contribution are the main contributing factors to the ability of an ESP equipped with a helicoaxial booster pump to handle a higher GVF than an ESP equipped with an AGH (Camillieri et al. 2011).

Case Studies: El Portón Field

Three wells were analyzed in the El Portón field—wells 1010, 1050, and 1072. The oilfield geological environment is the thrust front of the Neuquén fold and thrust belt that was formed during the Andean orogeny. This area is one of the most productive sites in the Neuquen basin.

The production history of the area described in this study began in April 1995 with the completion of the well 1001. Water injection started on July 2001 with four wells as a pilot, and continued over the next 4 years with another 12 wells. Gas-cap injection began on September 1998 in well 1062, adding well 1059 by the end of 2002.

For this area, the unit of interest is the Lower Troncoso member of Huitrín formation. At the top of the Lower Troncoso, the Upper Clay Troncoso (TAS) consists of fine-grained sandstone with clay matrix interbedded with continuous clay layers from 10- to 15-m thick. Below theres is the Troncoso permeable section, which is the main productive level of the oil field and which is distinctive for its clayless sandstones with medium to gross granulometry. Its average thickness is 50 m. The lowest part of the reservoir is completed by the Lower Clay Troncoso (TAI), composed of a sequence of low-porosity sandstones combined with clay layers. Its thickness reaches up to 35 m.

Reservoir pressure has been registered in most of the wells in this oil field. The wells from El Portón considered in this paper produce from an area that had an original pressure of 180 kg/cm^2. The level of reference for this datum is ~700 m, and it is described in **Table 1** and **Table 2.** Also the Chromatographic Analyses found in **Table 3**.

TABLE 1—OIL AT STANDARD CONDITIONS	
Density	**Viscosity**
35 °API	5 cP

TABLE 2—RESERVOIR PROPERTIES (PVT DATA)	
Reservoir temperature	64.3 °C
Bubblepoint pressure	147.2 kg/cm^2
Resistivity	101 m^3/m^3
Oil formation volume factor	1.3138 m^3/Sm^3
Density	0.728 g/cm^3
Viscosity	0.979 cp
Gas formation volume factor	0.0056 m^3/Sm^3

TABLE 1—AVERAGE RESULTS OF GAS CHROMATOGRAPHIC ANALYSES, 2008													
2008		**Chromatographic Analysis**											
Date	Production	N_2	CO_2	C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	$C6_+$	Sum	ρ	PCS
First Quarter	Discharge CHLS 1 (Chihuido la salina 1)	2.55	0.69	81.57	8.59	3.81	0.42	1.30	0.33	0.42	0.32	100.0	0.699	10501
First Quarter	Discharge CHLS 2 (Chihuido la salina 2)	2.67	0.74	82.24	8.08	3.67	0.41	1.2	0.31	0.38	0.31	100.0	0.693	10384

ESP systems have been used in this oil field since 2002. In particular, and due to combined production of gas, oil, and water, gas handlers are installed in most of the ESPs (approximately 90%). Currently, 40% of active wells are under this artificial lift system.

Although most of ESP wells have facilities for gas lift system, this system was not being used as the primary production method and it was only being activated when the pump was gas blocked. Water injection has been recently initiated on the field, but not yet spread to these wells. As a result, since no water injection is performed, these wells produce high gas volumes that must be managed by the downhole ESP.

Surveillance and Metrology Review

The monitoring techniques are as follows:

- The surface flow rates are sent through the flowline to a three-phase horizontal gas separator where liquids are separated from gas. Each of these flowlines has its own flow meter, which allows an accurate measurement of both phases.
- The ESP is fitted with a downhole gauge that measures the intake pressure at the ESP depth. The gauge's accuracy and resolution is ± 0.7 bar. This metrology is sufficient for the steady-state analysis performed in the current case study.
- A surveillance and control system is installed to monitor the well, alert the owner of possible problems, and allow operational adjustments remotely.
- Surface well testing is conducted between two to three times a month, depending on whether a setting such as ESP frequency has been changed in the well or any other condition is present (i.e., production loss, gas lock, etc.).

Case Study: Well 1010 (El Portón Field)

Production History and Multiphase Helicoaxial Pump Field Results.

As mentioned above, the analyzed well is produced using an ESP as an artificial lift method. Well 1010 was first installed with an ESP in February 2008. In October 2008 because of low production (fluid leakage on one of the gas lift mandrels), the equipment was pulled and optimized with a dynamic gas separating device. After 521 days of operation with high instability and constant gas-locking shutdowns (**Fig. 4),** the operator agreed to proceed with the optimization of the downhole equipment and installed the multiphase helicoaxial pump.

Results.

Before installing an ESP with a helicoaxial booster pump, well 1010 was produced using an ESP fitted with a gas handler and dynamic gas separator. The well was producing approximately 79.34 m^3/d of liquid and 32 m^3/d of oil. The ESP was operating with an average intake pressure of 3867.96 kPa and between 4819.44 and a minimum of 3164.69 kPa with an estimated GVF of approximately 40% at the pump's first stage. During this operating period the well exhibited:

- High instability and constant gas-lock shutdowns
- High intake-pressure variation
- High current fluctuation

Additionally

- Activation of the gas lift system was required to be able to continue producing the well when it was not possible to eliminate the gas lock.
- Continuous water injection through tubing had to be performed to eliminate the gas lock.
- Equipment was exposed to electrical stress generated by the constant shutdowns and startups of the ESP.

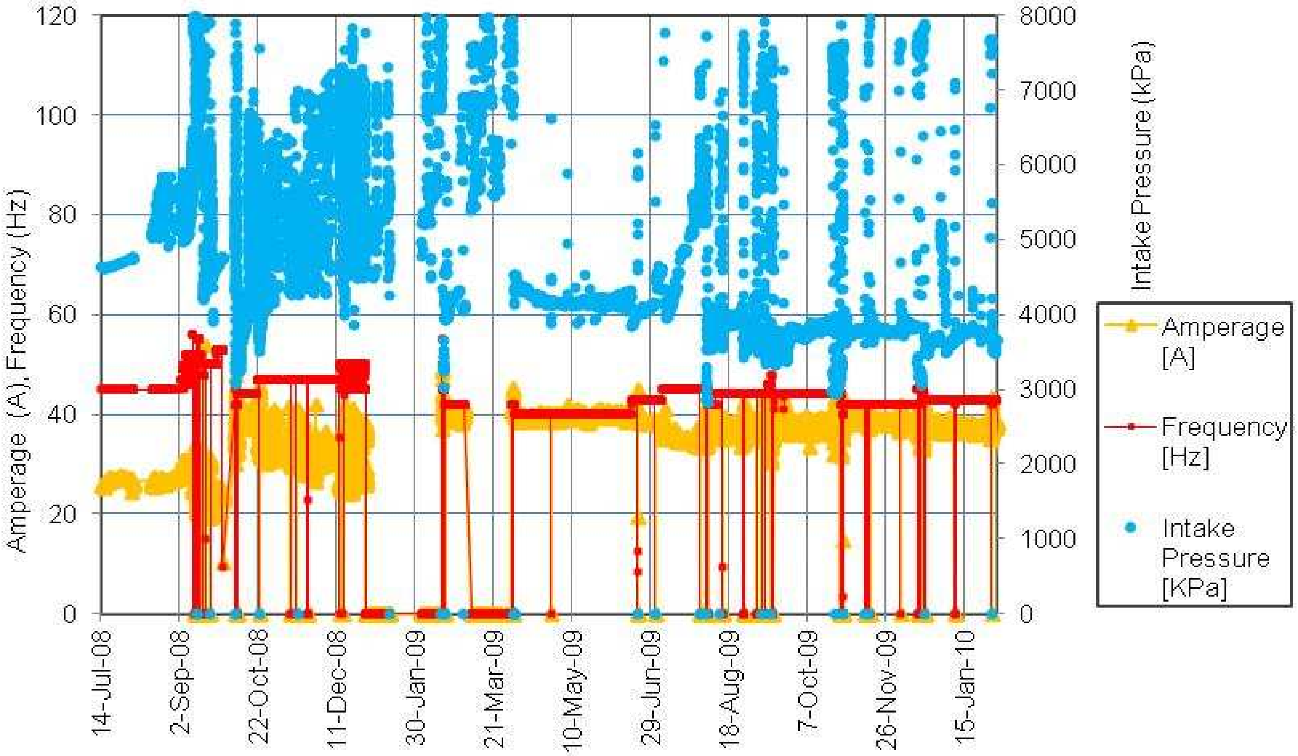

Fig. 4—ESP shutdowns due to gas lock before multiphase gas handler installation, well 1010.

By the end of March 2010, an ESP with the multiphase gas handler was run into the well, and results were as follows **(Fig.5)**:

- Shutdowns and startups due to gas lock were eliminated, increasing the well uptime and thus increasing production. The deferred oil production due to gas lock saved in just 1 year of operation with the helicoaxial pump was of 270 m^3 and 204 702 m^3 of gas.
- The total oil production losses registered by the client for the same period were reduced from 766 m^3 to as low as 88 m^3. Regarding the gas production, losses dropped from 509 703 m^3 to 83 704.6 m^3.
- The ESP continued operating with an approximate GVF of 40%, but eliminating the shutdowns caused when the operating limits of the AGH were being exceeded.
- Cost savings were realized by eliminating the need to contract a third party company to inject water by tubing in each gas-locking shutdown and also avoiding the need to contract a supplier to install a gas compressor in the casing to be able to extract the free gas.
- Production parameters such as wellhead pressure were stabilized.

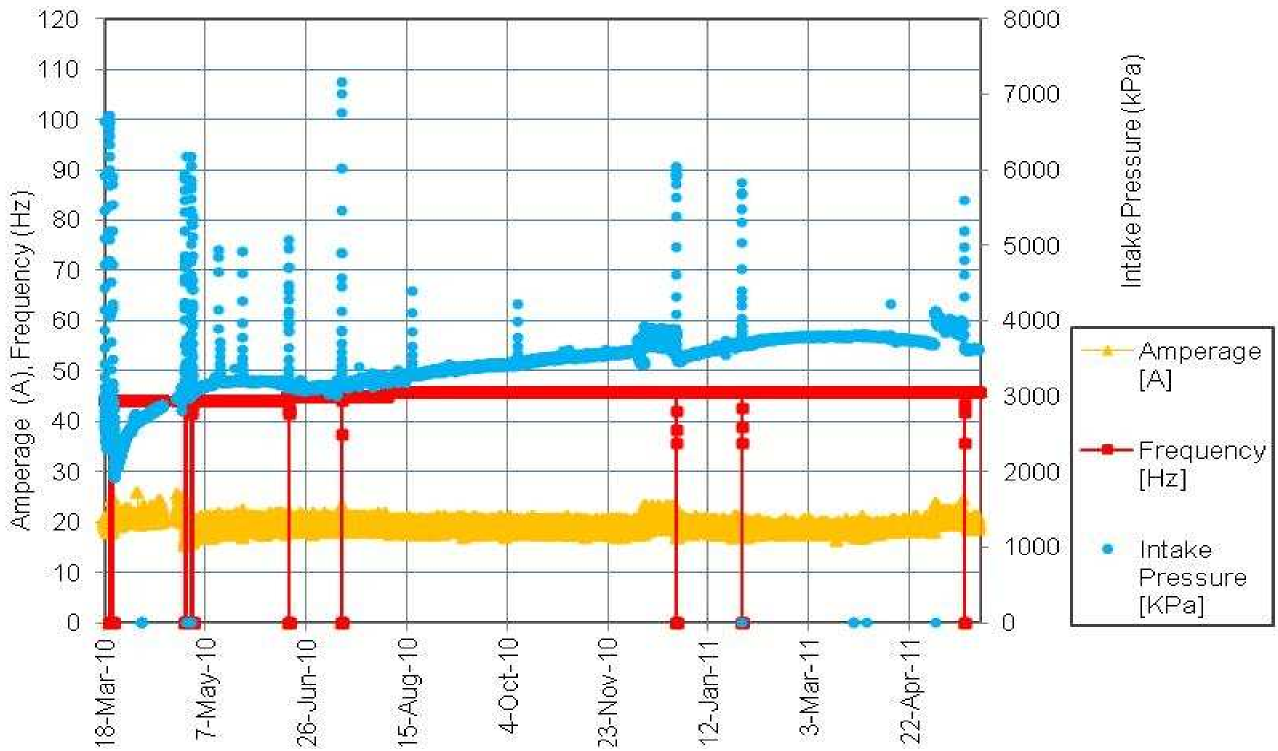

Fig. 5—ESP behavior after helicoaxial gas handler installation, well 1010. Gas-lock shutdowns 100% eliminated

Even when the average oil production did not increase, shutdowns due to gas lock were eliminated, reducing the oil and gas losses. The production of the well was also stabilized **(Fig. 6 and Fig. 7)** allowing intake pressure to be dropped by up to 2137.373 kPa and with an average of 3171.59 kPa during the first year of operation **(Fig. 8).**

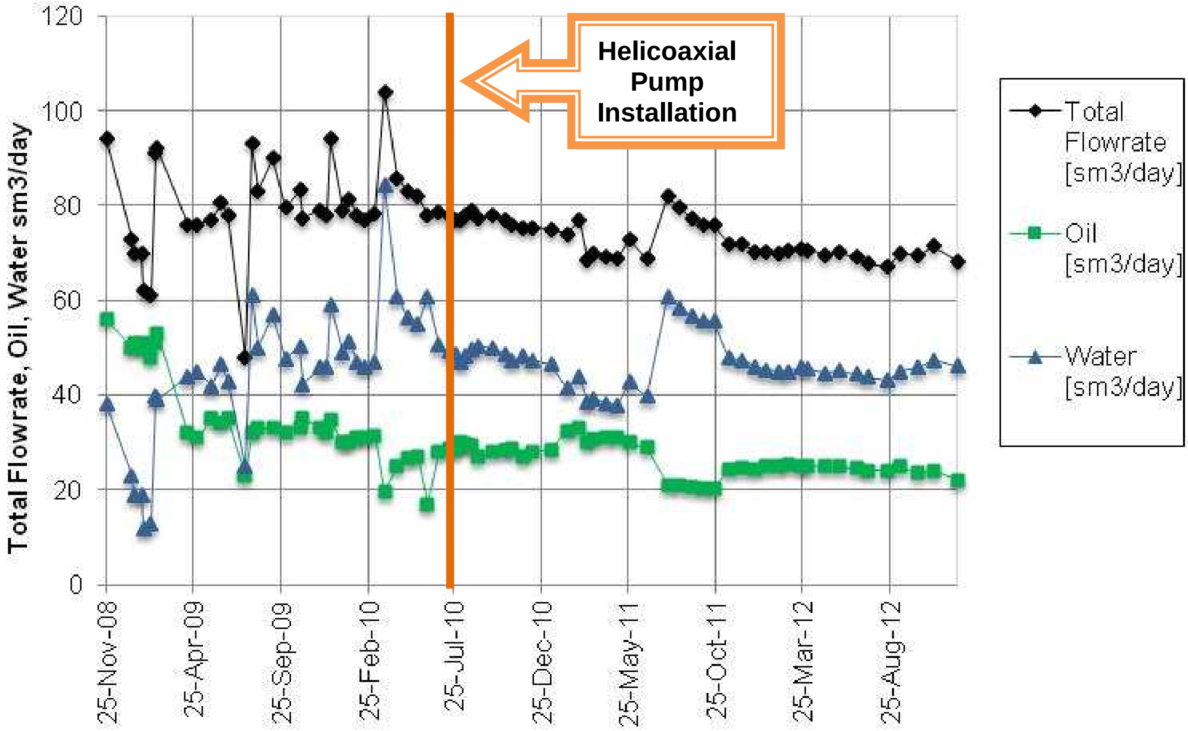

Fig. 6—Production stabilization after multiphase gas handler installation, well 1010.

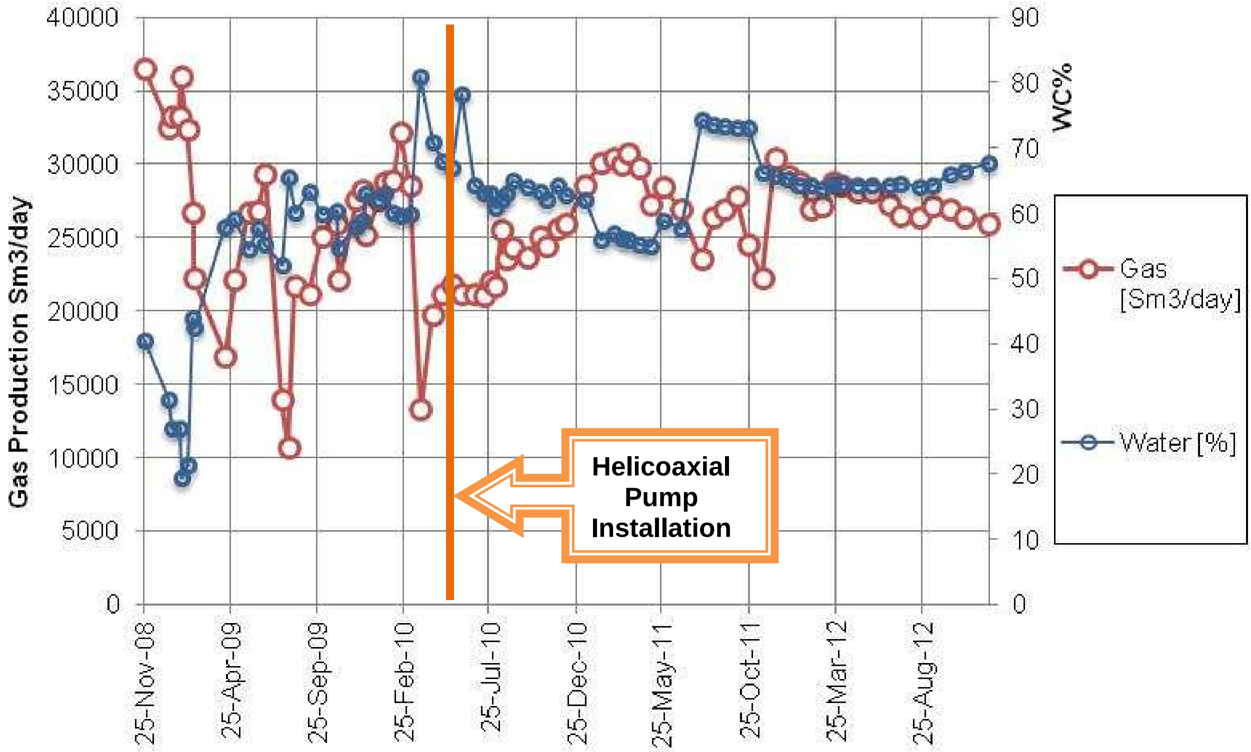

Fig. 7—Gas production stabilization after multiphase gas handler installation, well 1010.

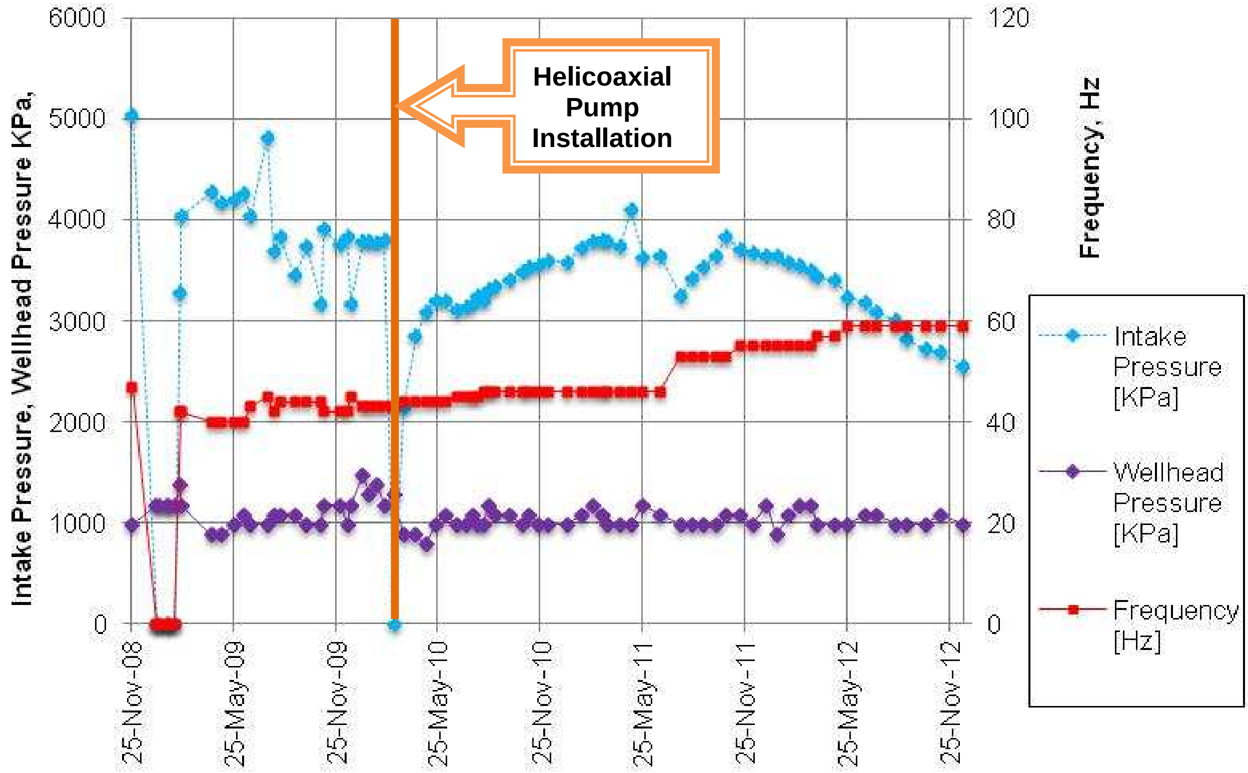

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Fig. 8—Surface and downhole pressure stabilization after multiphase gas handler installation, well 1010.

Case Study: Well 1050 (El Portón Field)

Production History and Multiphase Helicoaxial Pump Field Results.

Well 1050 was initially produced using gas lift. During this period, to produce the well, it was required to inject approximately 17 000 m^3/d of gas to recover an average oil production of 22 m^3/d and 6000 m^3/d of gas. Since production was low, the operator decided to switch the lifting method and replace the gas lift with an ESP system. The ESP installed was equipped with a standard gas separator and an AGH and run for more than 2 years. Oil production ranged from a minimum of 20 m^3/d to a maximum of 69 m^3/d and with a gas production variation from 1546 m^3/d to 21 600 m^3/d. As the gas production began to increase, the standard gas separator was replaced by a dynamic gas separating device (plus AGH) with the following results: average oil production 33 m^3/d, average gas production 34 000 m^3/d, and approximate GVF at first pump stage above 40%. Since the ESP began to show high instability and the total production began to continuously decrease, the operator decided to remove the ESP and proceed, once again, with the reactivation of the gas lift system.

Results.

Before the installation of an ESP with a multiphase helicoaxial pump, well performance with the gas lift was as follows:

- The total flow rate as well as the oil production began to continuously decrease ranging from a maximum of 59 to 19.9 m^3/d of total flow rate (26 to 7.5 m^3/d of oil) and 42 000 to 140 m^3/d of gas. The average gas production during this operating period was of 19 000 m^3/d with an average oil production of 19 m^3/d.
- The operator had to inject an average of 14 000 m^3/d of gas with a maximum of 25 590m^3 to be able to produce the well.
- The wellhead pressure exhibited oscillations between 1373 and 2157 kPa.

In January 2012, an ESP with a multiphase helicoaxial pump was installed with the following results:

- Production parameters were stabilized **(Fig. 9).**
- The average oil production remained without much variation at approximately 18.8 m^3/d. Water cut was also stabilized and close to 64%.
- The gas production greatly increased and was also stabilized with a new average daily production of 46 700 m^3. Maximum gas production reached the 54 800 m^3/d during the considered operating period **(Fig. 10).**
- The simulated GVF at the first pump stage is close to 70%. Stops and starts caused by gas locking remained low, increasing the well uptime and thus production, even with such high volume of gas going through the stages of the pump.
- Wellhead pressure is now close to 2200 kPa and up to 3500 kPa **(Fig. 11).**
- To keep stable operation, the ESP is now being operated in current mode with optimal results **(Fig. 12).**

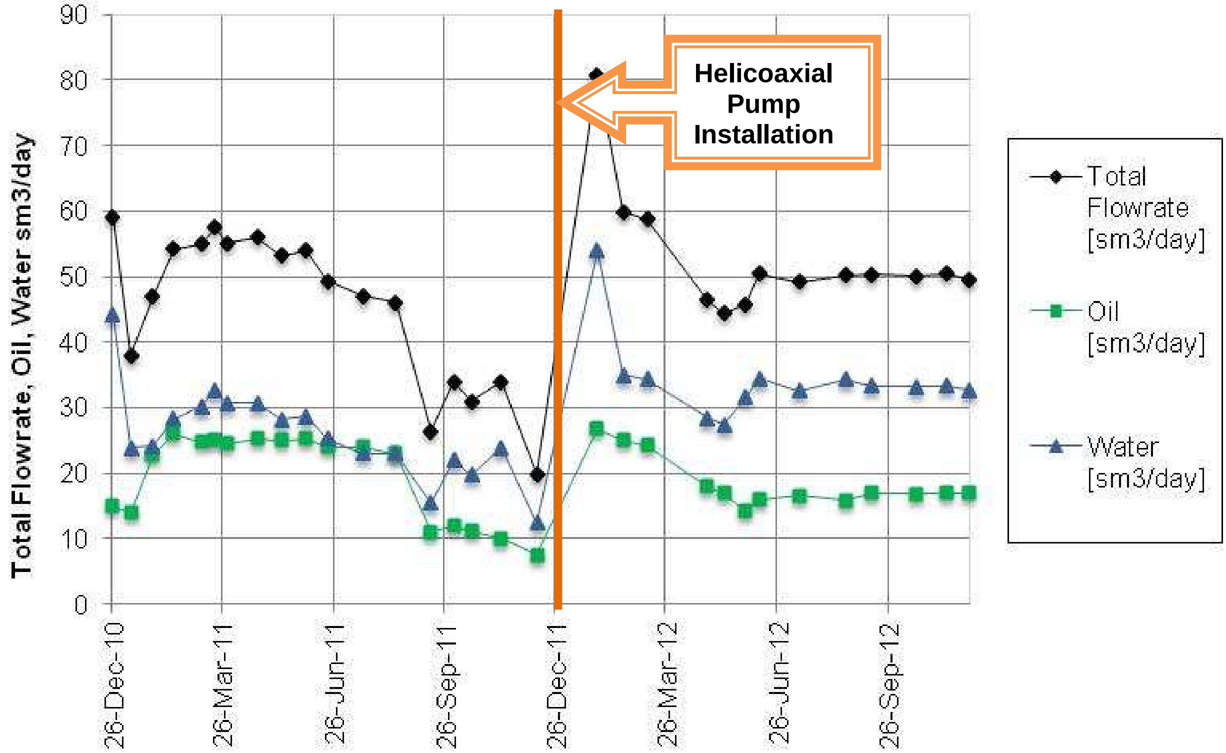

Fig. 9—Well production stabilization after multiphase gas handler installation, well 1050.

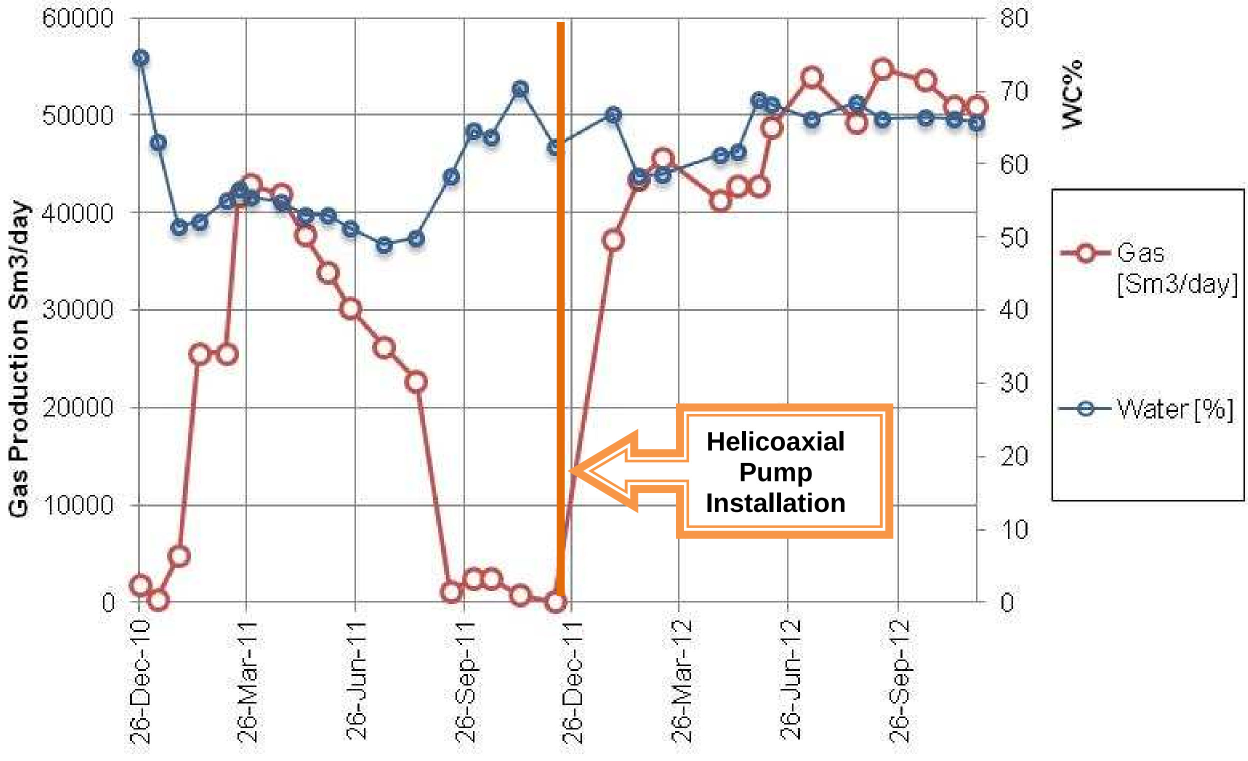

Fig. 10—Gas production increasing and then stabilizing after multiphase gas handler installation, well 1050.

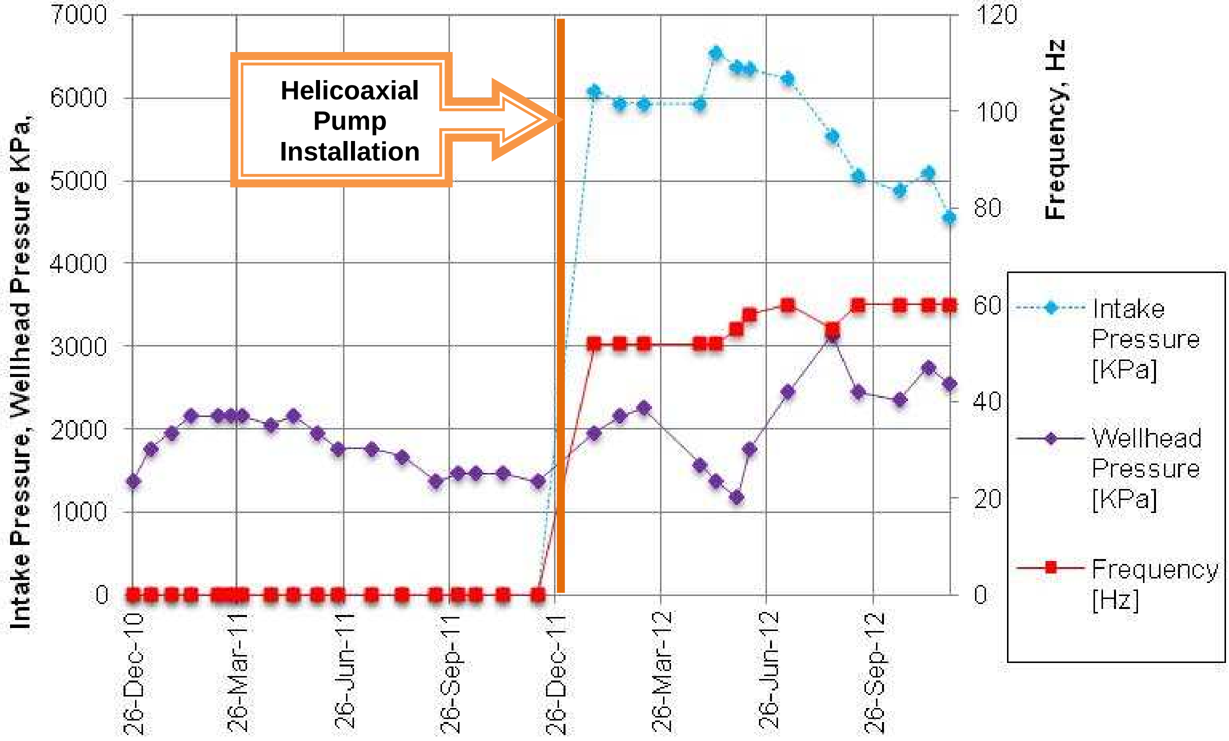

Fig. 11—Intake pressure reduction.Wellhead pressure variations, well 1050.

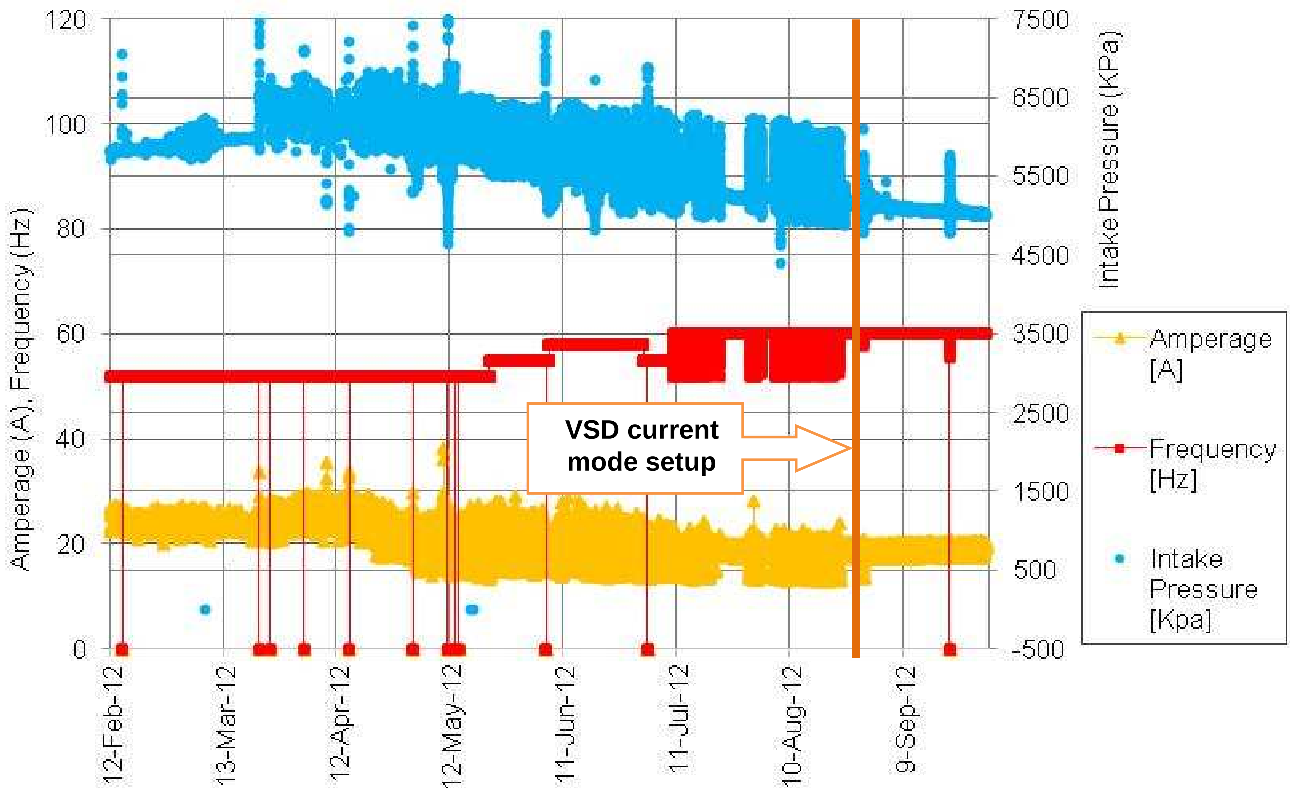

Fig. 12—ESP operating parameters since start up showing a continuous reduction in intake pressure and well stabilization with operational adjustments (variable speed drive current mode), well 1050.

Case study: Well 1072 (El Portón Field)

Production History and Multiphase Helicoaxial Pump Field Results.

Well 1072 exhibited high instability with the original ESP installation before fitting a helicoaxial booster pump. The exhibited behavior can be summarized as follows **(Fig. 13)**:

- Intake pressure oscillation, with a pressure swing up to 5500 kPa in operation
- High ESP current fluctuation of up to 14 Amps
- Several gas locking shutdowns due to gas lock of the pump
- Estimated GVF with the simulator up to 41% at the ESP first pump stage, operating at the maximum capability of the installed gas handler (AGH).
- Average gas production of ~17 000 m^3/d; average water cut of 53%.
- Continuous decrease in total flow rate, which ranged from 156 m^3/d to a minimum of 76 m^3/d for the period considered before the downhole equipment optimization

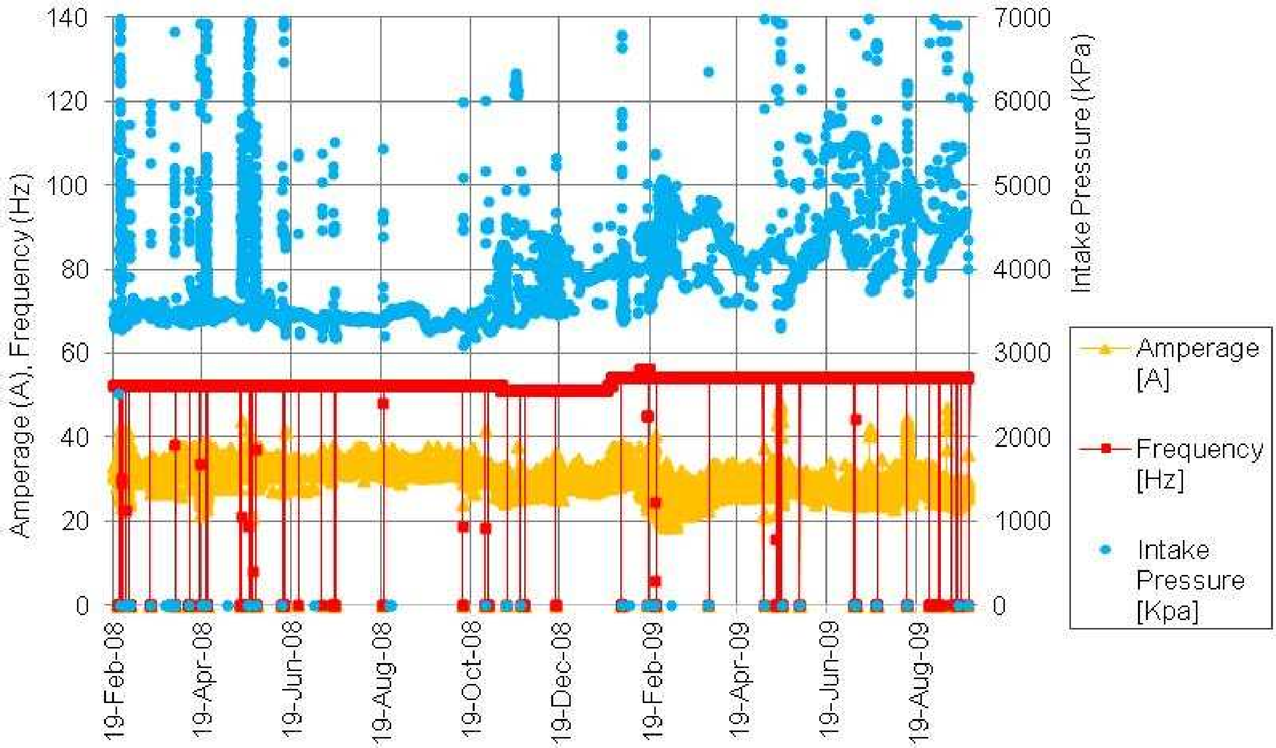

Fig. 13—High instability period with multiple well shutdowns, well 1072.

After the installation of the multiphase helicoaxial pump several operational changes were observed:

- The average gas production after the optimization was 53 000m^3/d, with a minimum of 23 000 and a maximum of 100 900 m^3/d **(Fig. 14).**
- Stops and starts caused by gas locking were reduced, increasing the well uptime and thus increasing production while operating under continuously increasing gas production **(Fig. 15).**
- Water cut remained stable at an average 53%.
- The total flow rate (oil + water) was stabilized, changing the original declining curve of the well **(Fig. 16)**.
- Wellhead pressure as well as the operating frequency had to be periodically adjusted to maintain stable operation **(Fig. 17)**.
- The simulated GVF after the installation of the helicoaxial pump was above 60%.

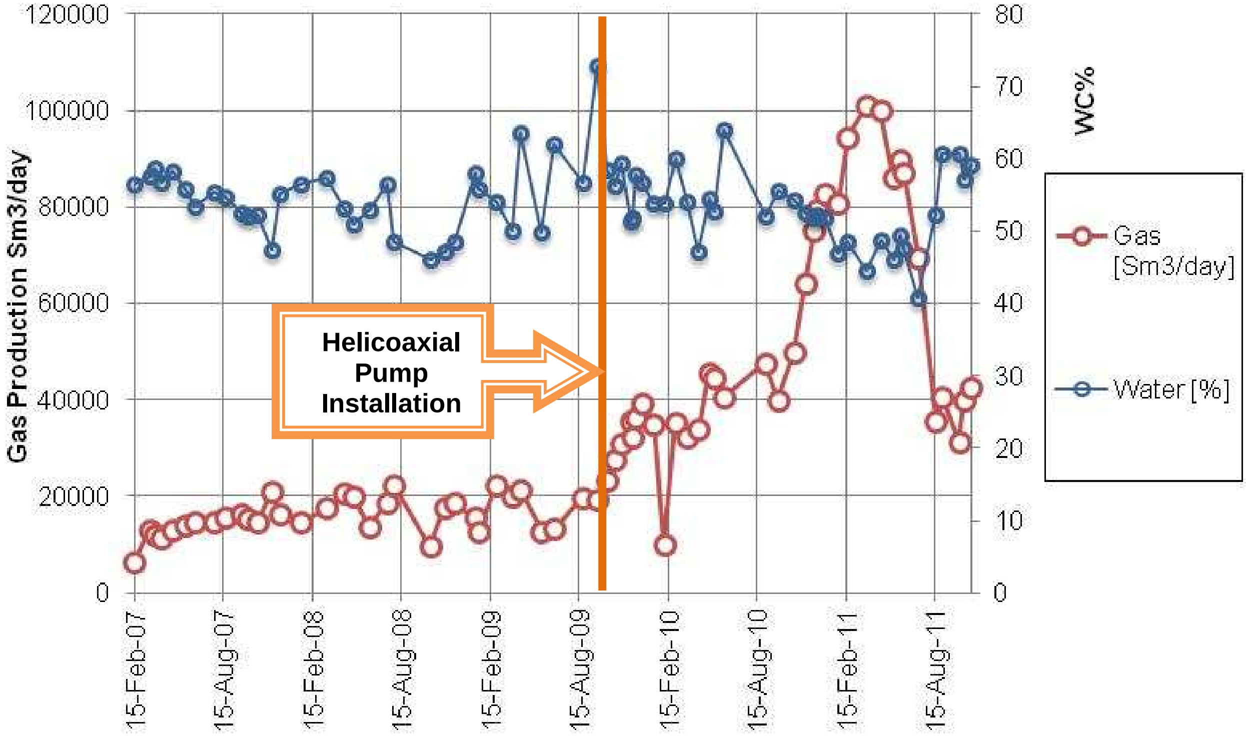

Fig. 14—Gas production increasing after multiphase gas handler installation, well 1072.

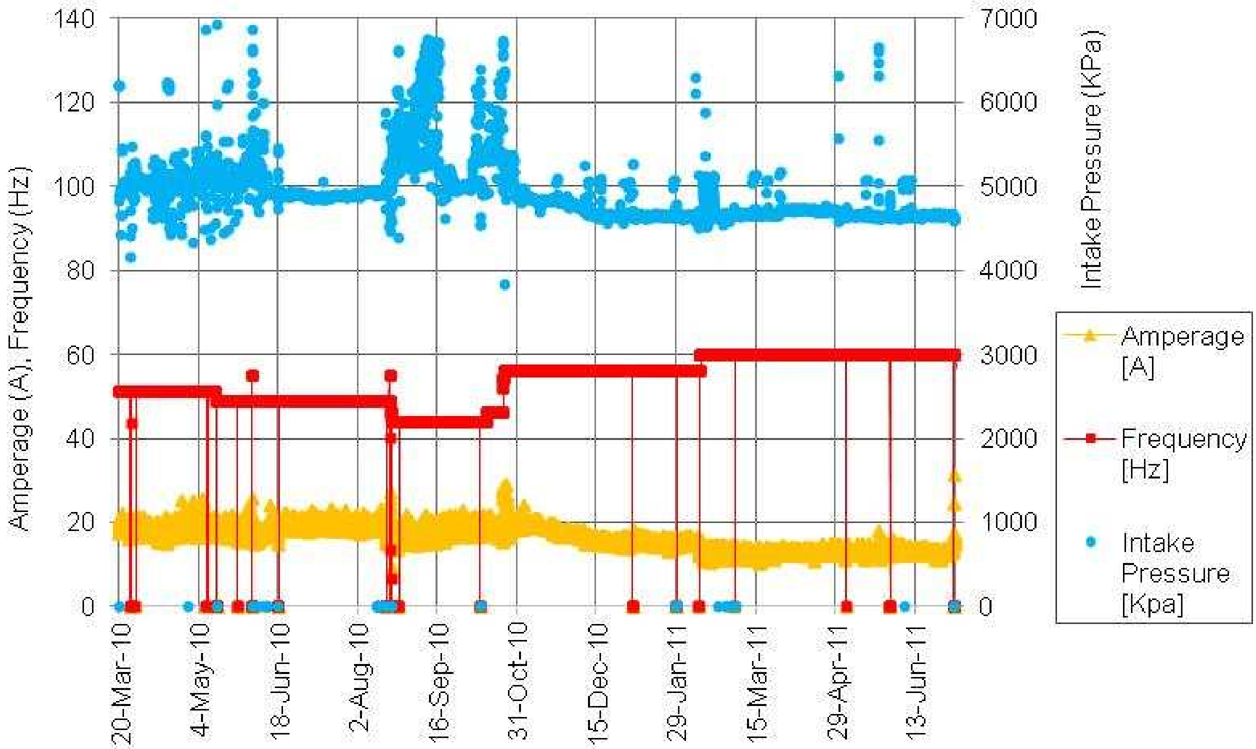

Fig. 15—ESP operational behavior and intake pressure after helicoaxial pump installation, well 1072; the high gas production period is evident,

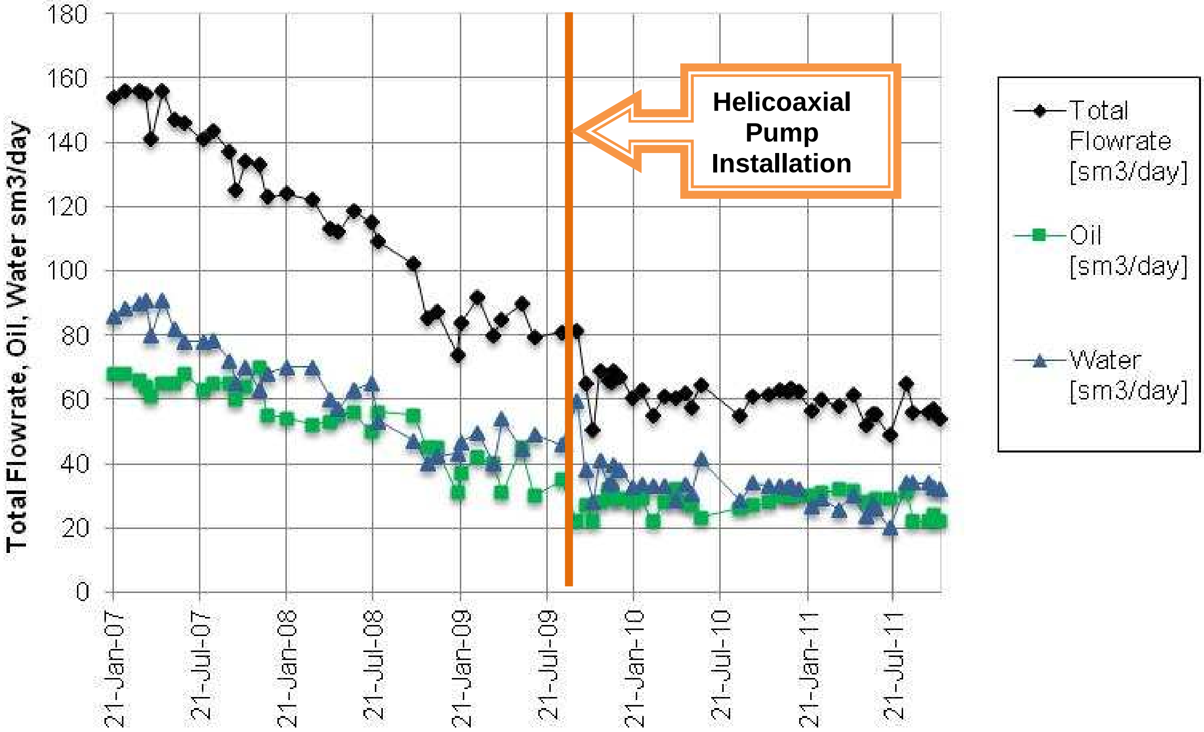

Fig. 16—Production stabilization after helicoaxial pump installation, well 1072.

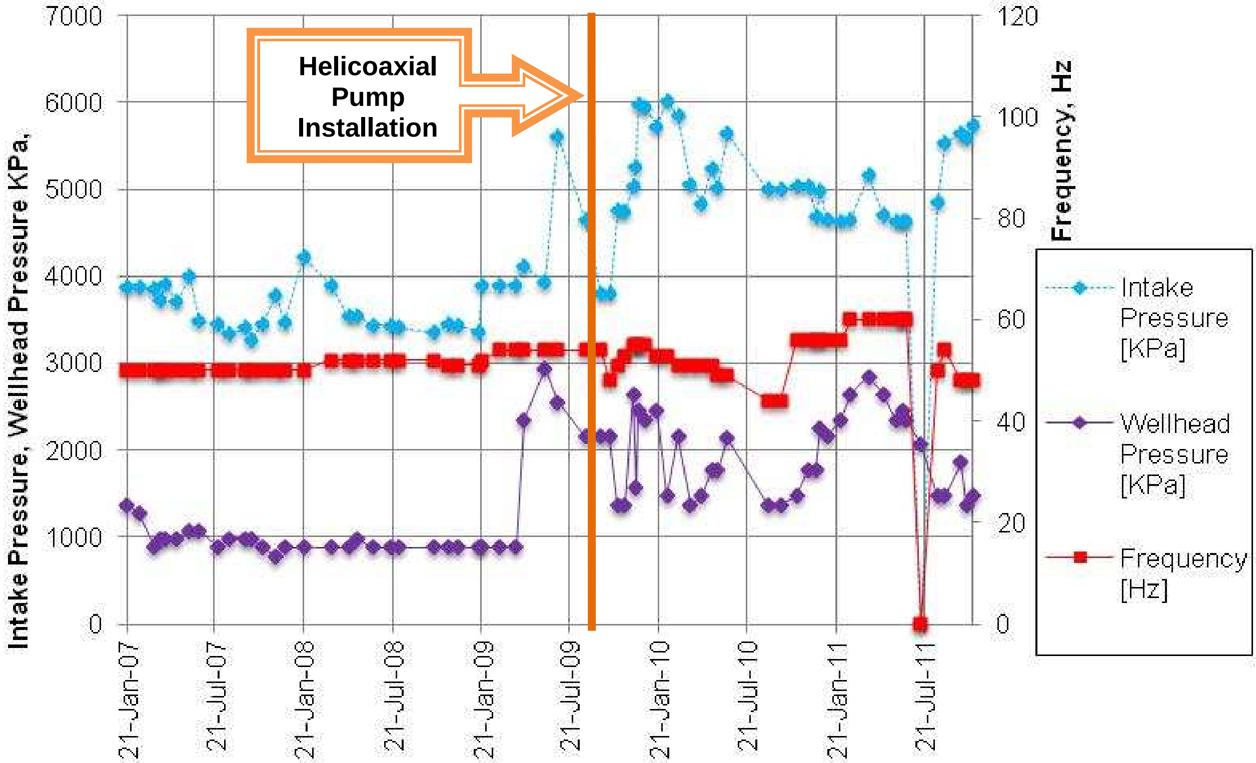

Fig. 17—After the installation of the helicoaxial pump in well 1072, operational frequency had to be continuously adjusted because of increasing gas production.

Case study: Volcan Auca Mahuida Field

One well, well 40, was analyzed in the Volcan Auca Mahuida field.

Production History, Production Difficulties and Results.

Well 40 was drilled in November 2008. The reservoir is composed of two productive formations, Centenario Inferior and Mulichinco, both formations still in primary oil recovery. This is a 20° deviated well with a maximum dogleg of 3.48°/30.5 m. The early production of this well was performed with a sucker rod pump (2590-m setting depth) using an antilock gas device, a ring valve, and a gas separator at the pump intake. With this method, it was possible to achieve an average total production of 47 m^3/day with ~ 41% water cut. Since startup the rod pump experienced issues such us rod string stress and tubing wearing because of the high load present and variable pumping speed due to the well's deviation and pump setting depth. As a consequence, during this operating period, the mean time between failures (MTBF) achieved was as low as 76 days.

In August 2009, the oilfield operator decided to change the artificial lift system into an ESP. To perform this operation, several technical issues had to be considered:

- Bottomhole temperature of 100 °C
- Dogleg severity of 3.48°/30.5 m)
- Low fluid flow 47 to 55 m^3/d
- High gas/oil ratio
- Sand production
- Setting depth

The first ESP configuration was installed with a dynamic gas separating device and an AGH. From the beginning, this equipment configuration did not reach the expected performance; issues included high motor current fluctuations due to gas handling, very frequent gas-lock shutdowns and, consequently, stuck pumps (sand), increasing downtime, motor burnings, and power cable failures.

As mentioned above, sand production (fines production) began to be an issue on every ESP shutdown in addition to the high gas volume managed by the stages of the ESP.

The MTBF after the installation of the ESP with the above configuration was of 105 days against the 76 days achieved with the rod pump.

Results.

Since well 40 exhibited high instability with the original ESP installation, the operator decided to fit a helicoaxial booster pump to the string.

As described above, production difficulties were

- The ESP experienced high current fluctuations.(**Fig.18).**
- The GVF was estimated to be close to operational limit of the AGH due to the frequent gas lock of the ESP. The uncertainty in the estimate is because of the lack of facilities to perform the measures.
- ESP gas lock resulted in large production downtimes.
- Fluid pumping through tubing assistance was needed to unlock the ESP and to eliminate stuck sand.
- Several motor burnings, power cable failures, and sand blocking of pump stages resulted in an increase in the pulling index.

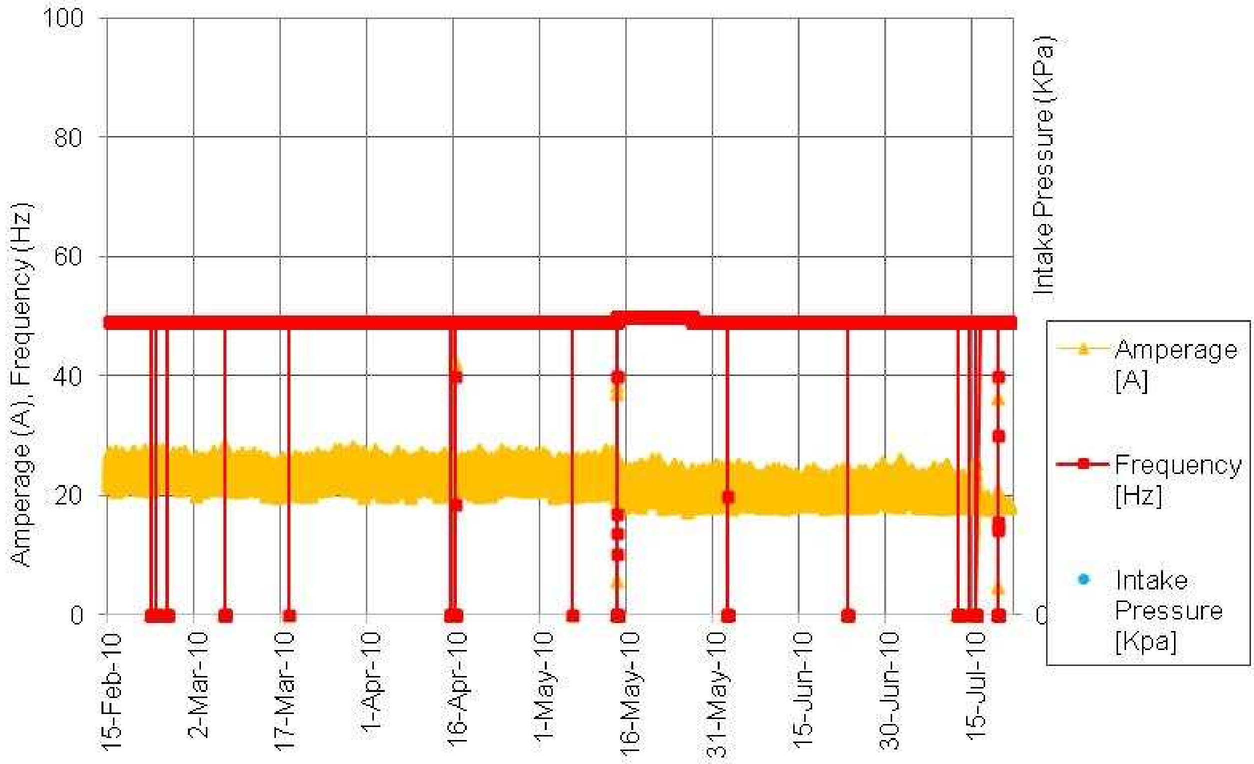

Fig. 18—ESP behavior in well 40 before optimization; no downhole sensor was installed.

In July 2010, a multiphase helicoaxial pump was installed to help to overcome the production difficulties mentioned above and with the following results:

- ESP shutdowns caused by gas locking were eliminated, which increased the well uptime and thus increased production **(Fig. 19).**
- Total flow rate increased ~45%, from an average 49 m^3/day to more than 75 m^3/day and with an increase in the total oil of ~25% from an average 31 m^3/day to 42.5 m^3/day **(Fig. 20).**
- Workover interventions due to motor or power cable failures decreased.
- The need of continuous technical assistance due to gas lock and stuck pumps was practically eliminated; the helicoaxial pump allowed setting the ESP string above perforations, reducing the risk of gas lock and stuck sand.
- The MTBF increased from 105 days to an average above 220 days. Recently, longer running periods were achieved; at this time, the equipment has been running for more than 320 days.

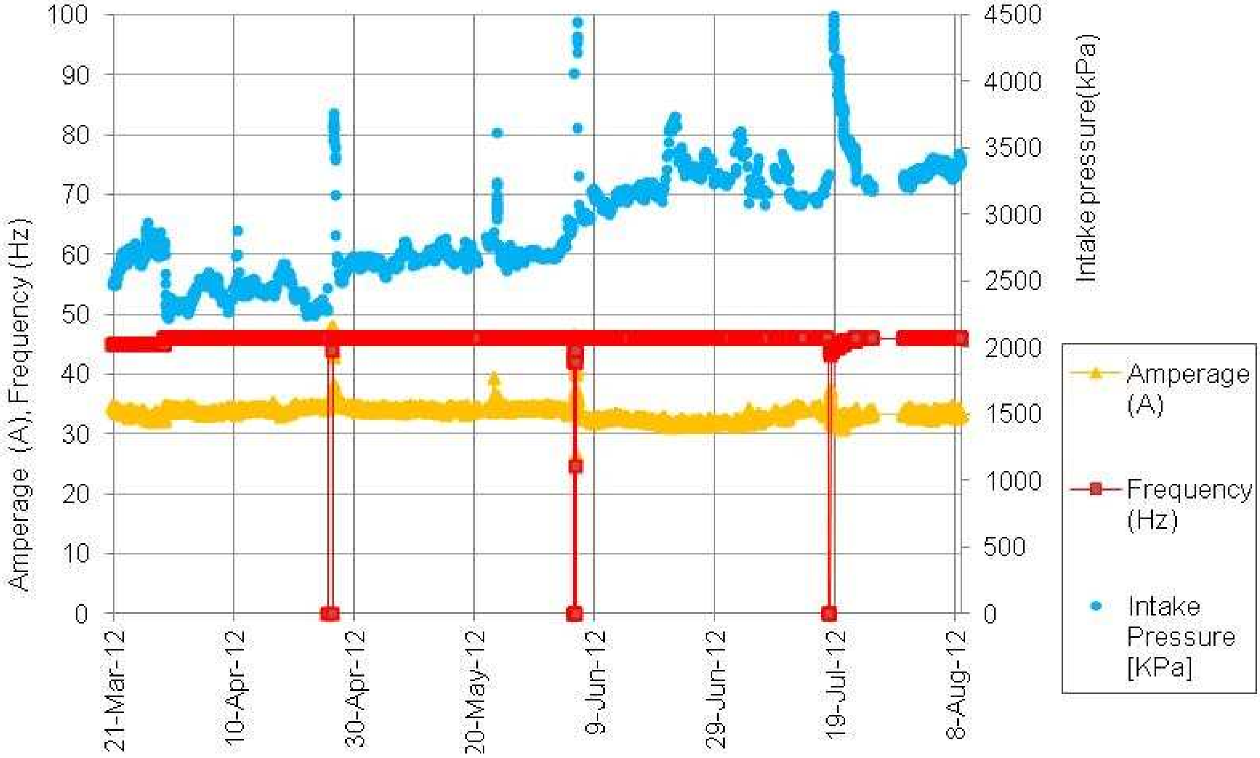

Fig. 19—Well behavior and ESP operating parameters after optimization, well 40.

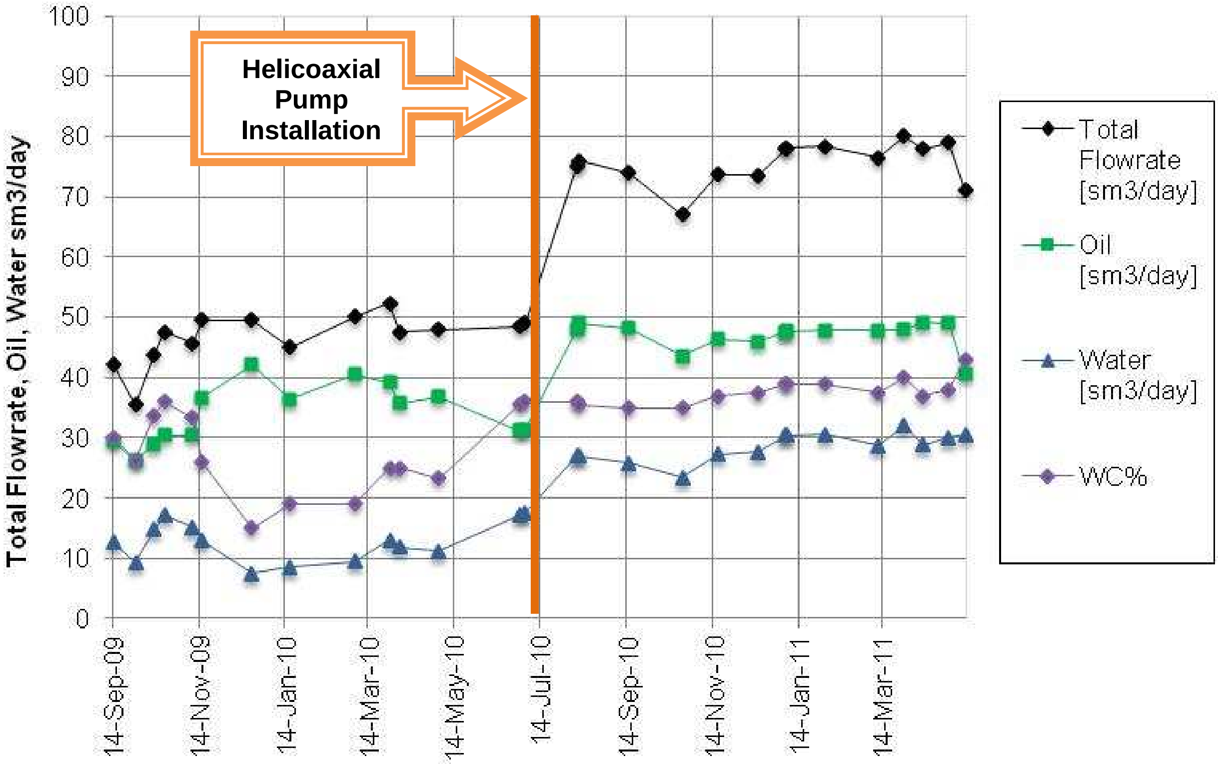

Fig.20—Production before and after helicoaxial pump installation,well 40, showing a 25% daily oil production increase.

Conclusions

- The helicoaxial pump has stabilized production and eliminated costly shutdowns.
- This pump contributed to increased production as a result of increasing drawdown and equipment uptime. This operating condition al lower intake pressures was also possible by installing downhole gauges as a monitoring tool.
- The motor current fluctuation (generated by the reduced load on the motor caused by the gas-locking of the pump) was also stabilized, reducing the electrical degradation suffered by the different electrical components of the ESP and increasing the expected run life.
- The multiphase helicoaxial pump enables ESP applications with GVF above 40% and up to 70% as demonstrated on the simulations of the production data provided.
- On wells 1050 and 1072, gas production has greatly increased as a result of multiphase helicoaxial pump installation. On well 40, daily oil production increased by ~ 25% and the MTBF moved from 105 days to an average above 220 days.
- Cost savings were realized by eliminating the need to contract a third party company to inject water by tubing in each gas-locking shutdown and also by avoiding the need to contract a supplier to install a gas compressor in the casing to be able to extract the free gas.
- Following the results of the studies in these fields, the operator has installed 25 multiphase helicoaxial booster pumps in other operations around the country and has plans for further installations. These installations will enable more ESP simulations and presentation of results.

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