NEW MECHANISM OF SAND MANAGEMENT ABOVE ESPs

Anderson Delgado, Jorge Espinosa, Gran Tierra; Luis Guanacas,
Gustavo Gonzalez, and Carlos Portilla,
Odessa Separator Inc.

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ABSTRACT

Extending the run life of wells with Electrical Submersible Pumps (ESP) becomes a crucial need since it is one of the most economically expensive types of ALS. Following the need, a sand regulator has been designed to protect the pump during shutdowns, and it has been incorporated into traditional sand control configurations to offer extensive protection above and below the pump. This paper will explain the mechanism of the sand regulator as well as the benefit of installing this system alone above the pump or complemented with a sand control system below the pump. Since the wells had sand problem history and it was necessary to review pump designs, pulling reports, and sensor parameters along with well conditions such as production, tubing size, and particle size distribution were analyzed to build the best design for every single well. In the design, the geometry of the well was assessed to accommodate the cable and CT line downhole. The Acordionero Field is characterized by heavy oil production (400-1000 BFPD), with a viscosity of 430 cP @ 150°F, API between 13-15, low water cuts (Between 3.9% to 20%), and high fine sand production (3000 - 5000 ppm). Cohembí Field wells produce between 1000 - 6000 BFPD, with API between 17-18, high water cuts (> 77%), and a high sand production between 500 - 3000 ppm. The wells selected had other types of sand control and management systems and were highly affected by frequent shutdowns. The Sand Regulator design was installed on 20 wells and was compared with the performance achieved using traditional sand control solutions. After the installation, production has remained stable in all the wells applied, allowing to reduce the PIP of the well from 900 psi to 500 psi. Less current consumption has been observed after each shutdown in all the wells, extending the run life of some wells from 108 days to more than a year. Sensor parameters were analyzed after each pump restart to determine how difficult it was to restart operation after shutdowns. Compared to the tools installed above the ESP, this sand regulator allows flushing operation through it with flow ranges from 0.5 to 5 bpm. In addition, the unconventional design of this tool has opened the door to a new concept of ESP protection that works in wells with light or heavy oil and can be refurbished or inspected completely without cutting the tool.

INTRODUCTION

Sand control has become one of the most important aspects of evaluation, whether a project is viable or not may be defined for the different sand control options in the market, especially in wells with high flow rate where the ESP system is currently one of the most used ALS. The sand management gets difficult when waterflooding is used as a secondary recovery method, this method helps flatten the declination curve of the field, but it causes an increase in sand production due to the injection pressure on the formation rock. A high sand production will cause many damages in the ESP system, when this enters in the pump the sand being either a formation nature or from a frac job it starts wearing the pump stages and the mechanical seal may present damage due to the vibration product of the presence of sand. The damage could create a path that will allow the fluid to flow through the seal and into the dielectric oil causing a failure in the system. The erosive nature of the sand will affect the impeller vanes affecting the hydraulic capacity of the pump this would increase the clearance on the stages triggering more recirculation and end up in a lower pump efficiency, which will increase the lifting cost. It is important to highlight that if there is a shutdown and there is sand inside the system when the ESP restarts, it may cause a broken shaft, or the pump wouldn't be able to start due to high motor current required. This last problem has become one of the main issues in two heavy oilfields in Colombia that use waterflooding. The oil viscosity and the high permeability of the reservoir caused a rapid breakthrough in the production wells and then increased the sand production as well. This research presents a solution to manage the sand production above the ESPs. The solution is compared with previous methods used for the same purpose and comparing parameters such as sand production, fluid production, pump frequency and run life.

SAND LIFT: SAND MANAGEMENT TOOL

The Sand Lift is a sand management system installed directly on the discharge of the pump. When the pump is producing fluids, this system does not represent a restriction to the fluid thanks to its large open area in the internal components, table 1 summarizes the total open area depending on the dimensions of the tool. In simulations carried out in computational flow models using up to 8,000 BFPD, pressure drops of less than 10 psi were estimated from the discharge of the pump to the neck section of the tool. Now, when the pump shuts off, the internal system of the Sand Lift works as a flow regulator to the pump. The internal inverted mesh mechanism reduces the amount of solids flowing towards the discharge of the pump, thus avoiding the saturation of the upper pump stages. An important feature unlike other technologies is that the Sand Lift does not have check valve systems, so it does not completely seal the tubing and allows flushing operations through the production tubing to the pump. This feature is especially beneficial in cases where solid control systems are not used below the pump, and it is desired to clean the sand stored in the pump stages. Acid treatments can also be injected without affecting the internal components of the Sand Lift.

During restart of pump operation, the Sand Lift uses pump discharge pressure as fuel to displace fluid and solids in its chamber. The internal design of the lower ports act as jet ports to sweep and break up any type of solid around. Computer simulation results have shown that the fluid velocity in the bottom jet ports can reach up to 132 in/s. It is important to clarify that this scenario is possible when the pump can reach enough discharge pressure, however, when there are solids in the lower pumps and an adequate discharge pressure cannot be generated, the system will not be able to generate the jetting effect, hence the importance of using combined sand control systems above and below the pump. After the reset, the fluid will move through the inner string and out through the inverted mesh into the tool body and then into the tubing. The inner string has a dart that travels up and down depending on the operation. The main purpose of the dart during the pump restart is to clean out the flow area inside the inner string and avoid sand packaging in the mesh. After the pump restarts, the dart will travel upwards opening the flow area below it and seating at the top section of the inner string in the dart garage. The complete tool operation is illustrated in figure 1.

The general design of this tool was thought to analyze its internal components after removing it from the well in order to provide production engineers with more information about types of solids, amount of solids and severity of downhole problems. Because of this all components of the Sand Lift are inspectable and replaceable without having to cut the tool. This design facilitates the inspection and reconditioning of the tool, which avoids cost overruns for the purchase of new equipment.

DESIGN AND CONSIDERATIONS

One of the main design variables is the amount of fluid expected and the pressure drop across the tool. This process is done through computational models and requires information such as pump discharge pressure, production flow, fluid properties and flow geometry. The Flow geometry refers to the dimensions and internal design of the Sand Lift's flow channels. The size of the tool largely depends on the factors mentioned above but also on the size of the production casing, the dimensions of the ESP pump cable and the size of the capillary (if applicable). Figure 2 shows the modeling of downhole tool size in accordance to casing and cable size. With this information, the pressure drops and flow rate through the tool are determined.

During installation, the tool can be lifted from the neck, which is already properly threaded from the factory, no additional tool is needed to lift or run the Sand lift (Box - Pin). It is recommended to install the Sand Lift directly on the pump discharge without adding spacing joints, this will improve the internal sweep efficiency on the body during pump restart. The banding procedure is performed as shown in figure 3, securing the cable on the neck and the upper and lower section of the body.

FIELDS BACKGROUND

The Sand Lift was installed in two Colombian fields owned by the multinational Gran Tierra Energy (GTE). Both Acordionero and Cohembi fields are producing through waterflooding as a secondary recovery method and produce heavy oil (13 - 17 API). The characteristics of the fields are summarized in table 3. Both fields have a high initial oil saturation and are developed with vertical wells. The flow properties of the reservoir are quite good in terms of permeability and thickness; however, the fluids are from medium to low mobility due to the viscosity of the oil. Both fields were developed with vertical wells with depths between 8,000 and 9,000 ft. the wells are completed with 7" production casing, and the ESPs are located above the perforations. Examples of the completion of these wells are shown in figure 4.

The Acordionero field is in the northeast of Colombia (Figure 5) at the Middle Magdalena Valley and was acquired by Gran Tierra Energy in 2016, since then a rapid development campaign began, increasing the number of producing and injection wells (Figure 6), achieving the flattening of the declination curve of the field. This is the largest field of the company and produced 53% of the total oil production in 2021. The Prudent reservoir management of the waterflood has restored production to an average level of 14,967 BOPD in Q4/21. After this rapid development, one of the challenges has been the reduction in the operation costs mainly triggered by failures due to sand production. The company has created a “right sizing” program focus on implement key technical initiatives to optimize the equipment designs and try proved technologies to increase run life of the existed equipment.

The Cohembi field corresponds to the southeastern block (Figure 7), where GTE became the operator in 2019 and began the water injection process, achieving an excellent response in production, setting a production record in Q4 2021. The potential for This field is expected to be achieved through the expansion of production facilities, infill drilling and the optimization of artificial lift systems.

Both assets are in the filling phase of the water injection process, and in some wells the breakthrough of the water has already begun to affect the run life of the downhole equipment (figure 8), so from now on optimization processes seeking to increase the total accumulated production of oil and reduce well intervention and operating costs since as the field reaches maturity and water cuts increase, sand production will continue to increase and therefore the problems associated with its production.

CASE STUDIES

About 20 producer wells have been completed using the Sand Lift above the ESPs. the wells have wide production ranges that go from maximum productions of 273 BFPD to 6000 BFPD with water cuts from 2.4% to 77%. Sand productions have been recorded periodically, reporting values from 30 mg/L to more than 20,000 mg/L, which is quite a challenge for any downhole production system. Another of the characteristics of these wells is the low API degree (13° – 17° API), which, when mixed with the sand particles, generates a paste-like fluid that increases the risk of clogging both in the pump and in the accessories used at the bottom of the well. Figure 9 shows the summary of some wells installed with the Sand Lift and their current run life; All the wells included in this graph are running, so the data is up to date. The points on each of the bars show the maximum production after the installation of the Sand Lift. The detailed information of each of the wells will be reviewed below, but based on the results of the Run Life, the applications have been successful and show excellent behavior of the pump against speed increases. The measurement of sand production was recorded for each well and the amount of sand being produced through the pump and the Sand Lift can be evidenced. Three of the installed wells have solids control systems below the pump, but the others were simply installed with the Sand Lift above.

AC-77

Well completed for the first time in April 2021, so there is no information prior to the installation of the Sand Lift. Current run time of 324 days using a pump 538 with 172 stages and a motor XT1 With 287 Hp. The average liquid production of the well has been 240 BPFD with a maximum production of 363 BFPD. The maximum PIP has been 774 psi and the minimum 641 psi, while the pump frequency started at 39 Hz and increased to 45 Hz recently (Figure 10). The well produces with a water cut of 30% and with an API gravity of 14°. Regarding to sand production, the well produces an average of 19 mg/L of sand, with a maximum production of 27.81 mg/L and a minimum production of 8 mg/L, which can be classified as a low sand production well. From the sand produced, 32% are sand particles between 25-75 microns, 23% are particles between 75-150 microns, 23% particles between 150-300 microns, and 23% particles larger than 300 microns (Figure 10 – Particle size distribution, PSD). The low initial sand production expected and the small size of the particles, allowed a design for solids control using only the Sand Lift above the pump.

CHB-7

Well completed for the first time in May 2012 and it was completed with the Sand Lift in July 2021. Current run time of 247 days using a pump 538 with 226 stages and a XP motor with 287 Hp. Previous installations were carried out by another operator and the details about the failures were not available. The average liquid production of the well has been 3,135 BPFD with a maximum production of 5,086 BFPD and water cut of 66% and API gravity of 18°. The maximum PIP has been 892 psi and the minimum 220 psi, while the pump frequency has oscillated from a minimum of 47.90 Hz, a maximum of 64 Hz and an average of 52 Hz (Figure 11). No information about solids has been gathered.

AC-15

Well completed for the first time in September 2017 and it was completed with the Sand Lift in July 2021. Current run time of 258 days using a pump 538 with 172 stages and a motor XT1 With 339 Hp. The average liquid production of the well has been 803 BPFD with a maximum production of 1573 BFPD. The maximum PIP has been 996 psi and the minimum 491 psi, while the pump frequency has oscillated from a minimum of 48.10 Hz, a maximum of 52.60 Hz and an average of 51.28 Hz (Figure 12). The well produces with a water cut of 50% and with an API gravity of 14°. Regarding to sand production after the installation, the well produces an average of 484 mg/L of sand, with a maximum production of 2164 mg/L and a minimum production of 72 mg/L, which can be classified as a high sand production. Compared to the sand production before the installation (Avg. 195 mg/L), the current conditions are very harmful due to the water injection, but the downhole equipment has performed well avoiding failures due to the solid production. From the sand produced, 37% are sand particles between 25-75 microns, 39% are particles between 75-150 microns, 22% particles between 150-300 microns, and 3% particles larger than 300 microns (Figure 12 – Particle size distribution, PSD).

AC-18

This well was initially completed in November 2017 and had an average run life of 137 days before installing the Sand Lift. Table 3 shows the details of the most recent failures and the completions used on these installations. Different types of completions were used on this well and there were not optimal results after the first 4 years. The well was completed with the Sand Lift in July 2021, and it has achieved a run time of 242 days using a pump 538 with 180 stages and a XP motor with 350 Hp. The average liquid production of the well has been 552 BPFD with a maximum production of 917 BFPD. The maximum PIP has been 824 psi and the minimum 359 psi, while the pump frequency has oscillated from a minimum of 40 Hz, a maximum of 63.60 Hz and an average of 46.43 Hz (Figure 13). The well produces with a water cut of 30% and with an API gravity of 18°. Regarding to sand production after the installation, the well produces an average of 1,547 mg/L of sand, with a maximum production of 23,652 mg/L and a minimum production of 57 mg/L, which can be classified as a severe sand production. These conditions have changed drastically after the installation since the average sand production before installing the Sand Lift was 582 mg/L with a maximum of 1,764 mg/L. From the sand produced, 19% are sand particles between 25-75 microns, 32% are particles between 75-150 microns, 43% particles between 150-300 microns, and 7% particles larger than 300 microns (Figure 13 – Particle size distribution, PSD). During the diagnostic phase, it was proposed to carry out an installation with a double sand control system above and below the pump due to the high sand production recorded. Additionally, the granulometric distribution of the sand allowed separating up to 50% of the sand production before entering the pump without affecting the liquid production due to pressure drop. This comprehensive sand control system has exceeded the average historical run life of the well.

AC-9

This well was initially completed in March 2017 and has a gravel pack installed in 2019. After this workover, the well had an average run life of 108 days before installing the Sand Lift. Table 4 shows the details of the most recent failures and the completions used on these installations. Different types of completions were used on this well and there were not optimal results after the first 1.5 years. The well was completed with the Sand Lift in December 2021, and it has achieved a run time of 92 days using a pump 538 with 40 stages and a XP motor with 250 Hp. The average liquid production of the well has been 303 BPFD with a maximum production of 415 BFPD. The maximum PIP has been 685 psi and the minimum 169 psi, while the pump frequency has oscillated from a minimum of 43.80 Hz, a maximum of 61.00 Hz and an average of 46.92 Hz (Figure 14). The well produces with a water cut of 35% and with an API gravity of 18°. Regarding to sand production after the installation, the well produces an average of 163 mg/L of sand, with a maximum production of 540.14 mg/L and a minimum production of 47 mg/L, which can be classified as from medium to high sand production. From the sand produced, 53% are sand particles between 25-75 microns, 36% are particles between 75-150 microns, 7% particles between 150-300 microns, and 5% particles larger than 300 microns (Figure 14 – Particle size distribution, PSD). There are no records of sand distribution before the installation of the gravel pack, so it is likely that the sand control system is retaining the coarser particles while the finest material is still flowing to the wellbore. Currently the well is operating with the same frequency that before the installation of the Sand Lift and the production is increasing. The PIP has decreased from 500 psi to 171 psi and no issues related to sand has been reported so despite the high pressure drop and very likely the increasing sand production, no sand issues have been reported after 92 days running.

AC-79 and AC-83 are similar cases to AC-77, that is, they were completed from the beginning with the Sand Lift and are still running without any sand related problems. The graphs of sand, liquid, PIP and frequency production of AC-79 are shown in Figure 15. The liquid production had a maximum of 1554 BFPD and operating at 43.50 Hz and stabilized at 800 BFPD operating at a frequency of 40 Hz. Hz. Regarding sand production, a maximum of 129 mg/L and an average production of 80 mg/L have been recorded, which can be classified as an average sand production.

Finally, CHB-16 was installed in July 2021 reaching a maximum production of 5,000 BFPD operating at a frequency lower than that used before installation. Figure 16 shows the behavior after the installation where the production doubled and although the information on the production of solids has not been recorded, it can be assumed that the amount of solids flowing towards the pump also increased. This well has registered 244 days since its installation and has not presented any type of problem related to the production of solids.

CONCLUSION

- The use of a solids management system above the pump has improved the run life and the performance of ESP pumps, increasing the accumulated production of oil in reservoirs subjected to water injection and production of high-viscosity heavy crude oil.

- The acordionero field has had a reduction in operating expenses due to the decrease in interventions carried out during 2021, this success was in part the result of the optimization program of the artificial lift systems that allowed the use of proven technologies such as the Sand Lift.

- The Cohembi field reached a production record during 2021, and as evidenced, the ability to increase production without affecting the operation of the downhole pump was one of the key factors.

- The use of integrated solids control systems above and below the ESP pump proved to be adequate in wells with high sand production (sand production not found in the literature) and fine to medium solids size. although each case must undergo a rigorous evaluation that guarantees an adequate design of the size of the slot and the required mesh length.

- Two failures have been recorded to date; one was caused by loss of isolation material in the terminals of the pothead connector due to scale and the second hasn't be determined yet. The Sand Lifts from these wells were inspected to provide more information about the performance of the equipment and the failure cause.

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Table 1 Sand Lift Specifications

Description	Lifting Neck OD (in)	Body OD (in)	Top Connection	Bottom Connection	Capacity of the Cavity (in^3)	Total Open Area (in^2)
Series 350	2-7/8	3.500	2-7/8" EUE Box	2-7/8" EUE Pin	1453.613	293.600
Series 400	2-7/8	4.000	2-7/8" EUE Box	2-7/8" EUE Pin	2060.500	293.600
Series 450	2-7/8	4.500	2-7/8" EUE Box	2-7/8" EUE Pin	2773.082	293.600
Series 550	3-1/2	5.500	3-1/2" EUE Box	3-1/2" EUE Pin	4454.352	368.800

Table 2 Field Characteristic

Field Information		
	Acordionero	**Cohembi**
Initial Oil Saturation (%)	78%	90%
Reservoir Thickness	330 ft	125 ft
Avg. Permeability	750 mD	2500 mD
Reservoir Depth	8000 ft	9100 ft
Viscosity	230 cP	28 cP
Recovery Method	Waterflooding	Waterflooding

Table 3 Intervention summary AC-18

Well	Reservoir	ALS	Start Date	Stop Date	Run Life	Status	Job Category	Comments	Accessory	Pump	stgs	Motor	Motor HP
AC-18	Lis A+C	ESP	7/16/2019	12/9/2019	146	Failed	Non-ALS Failure	Upper Pump Plugged Impellers.	SG 400	400	402	XP	250
AC-18	Lis A+C	ESP	12/21/2019	12/29/2019	8	Failed	ALS Failure	Upper Pump (7)	SG 538	538	168	XP	350
AC-18	Lis A	ESP	1/18/2020	9/19/2020	245	Failed	ALS Failure	Tubing plugged. Broken Shaft in the upper pump	TDV	400	293	XP	220
AC-18	Lis A	ESP	10/20/2020	10/26/2020	6	Failed	ALS Failure	Broken shaft due to solids, Impellers destroyed	N/A	538	172	XT1	205
AC-18	Lis A	V PUMP	2/4/2021	2/11/2021	7	Failed	ALS Failure	Broken shaft in the lower pump Stgg #1	N/A	400	120	MAXIMUS	270
AC-18	Lis A	V PUMP	3/25/2021	7/16/2021	113	Failed	ALS Failure	Broken shaft. Lower Pump full of solids	N/A	400	120	MAXIMUS	270

Table 4 Intervention summary AC-9

Well	Reservoir	ALS	Start Date	Stop Date	Run Life	Status	Job Category	Comments	Accessory	Pump	stgs	Motor	Motor HP
AC-9	Lis C	ESP	3/29/2017	7/12/2019	835	WO	Non-Failure	Isolation due to gas conning	N/A	400	16	MSP3	252
AC-9	Lis A	ESP	8/6/2019	9/25/2019	50	Failed	ALS Failure	Upper pump (last stage base-head)	SG 538	538	40	XP	250
AC-9	Lis A+C	ESP	10/10/2019	10/13/2019	3	Failed	ALS Failure	Tubing plugging 42 jnt; create overhead Upper pump - housing MLE melted	SG 400	538	40	XP	250
AC-9	Lis A+C	ESP	11/11/2019	2/13/2020	94	Failed	ALS Failure	Upper pump (5)-Broken	SG 400	538	40	XP	350
AC-9	Lis A+C	ESP	3/17/2020	12/30/2020	288	Failed	ALS Failure	Stuck pump, sand fall back	SG 400	538	40	XP	250

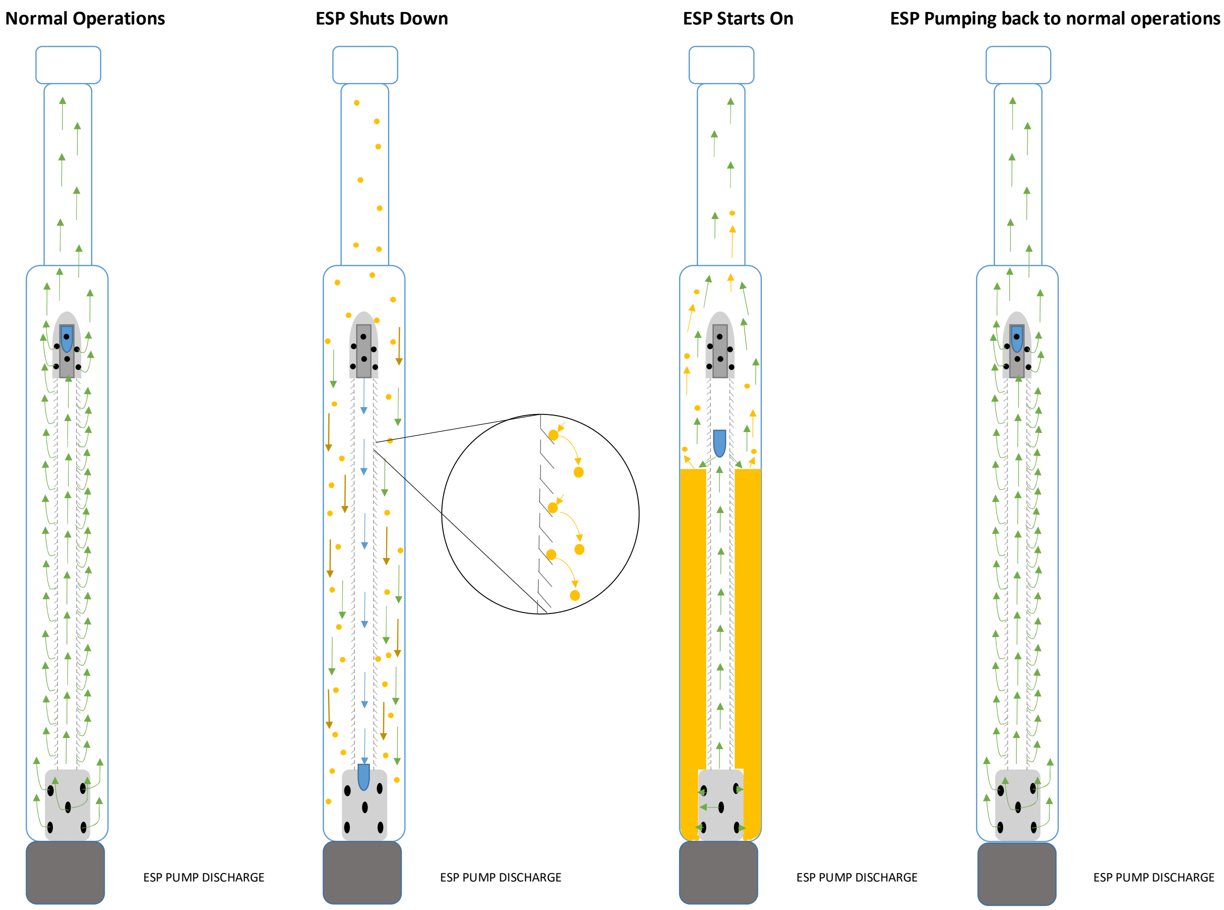


Figure 1 Sand Lift operation

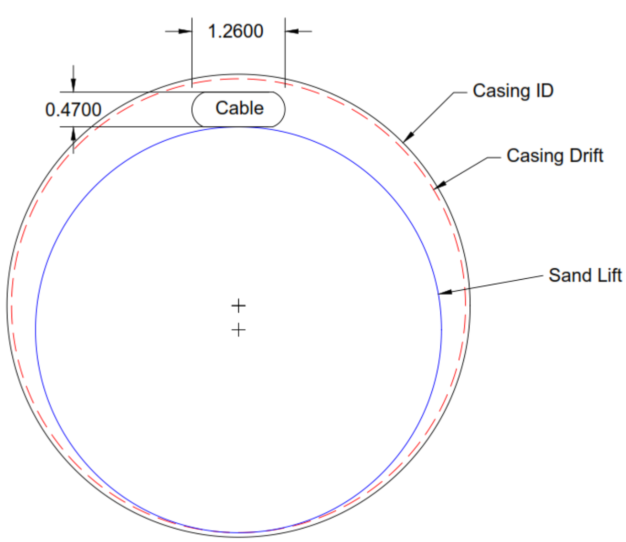


Figure 2 Sand Lift dimensioning

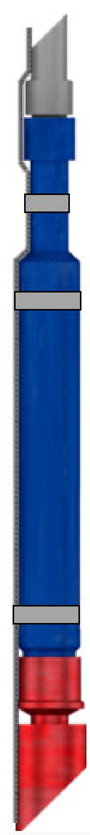
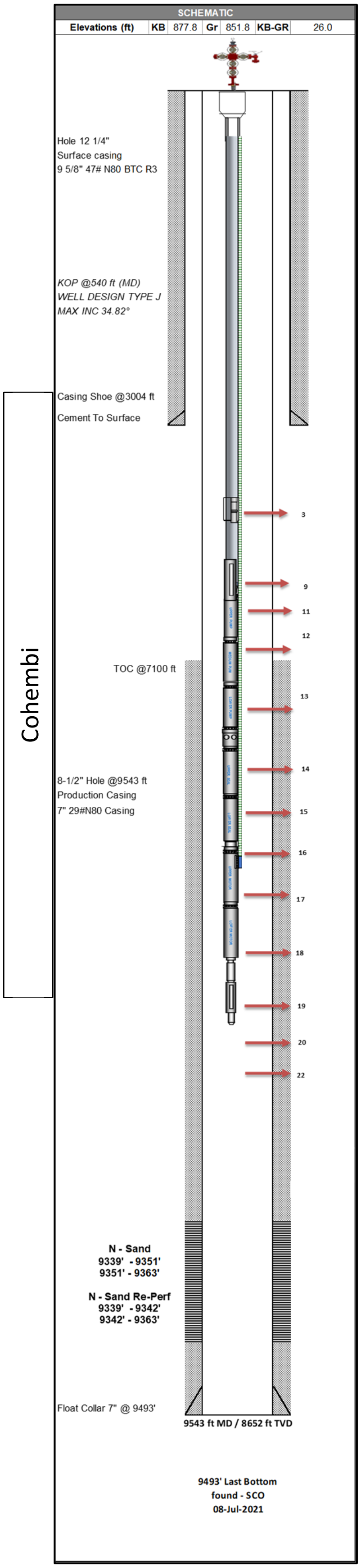


Figure 3 Bunding Procedure



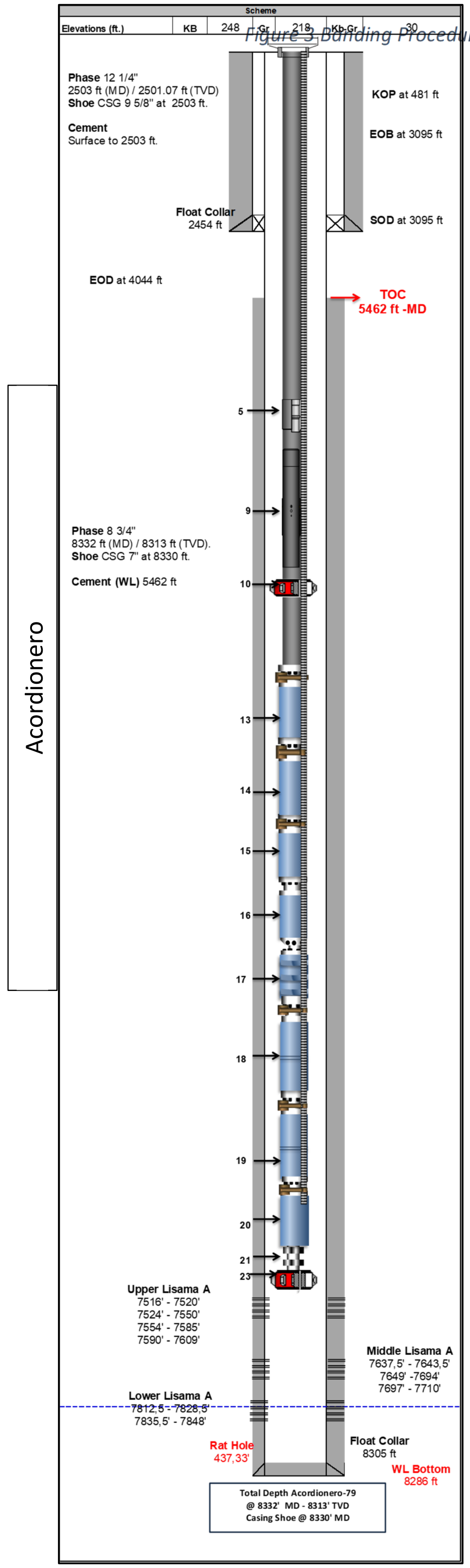


Figure 5 Acordionero field - Colombia

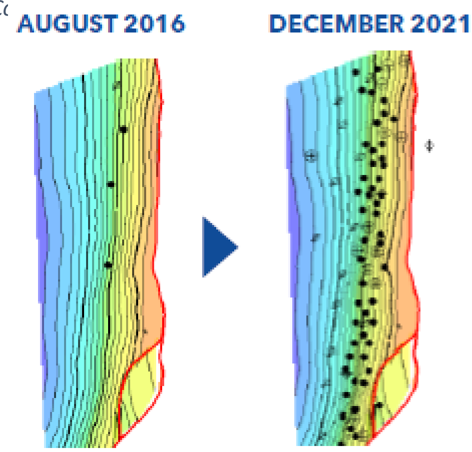


Figure 4 Acordionero Field Development

Figure 6 Cohembi Field - Colombia

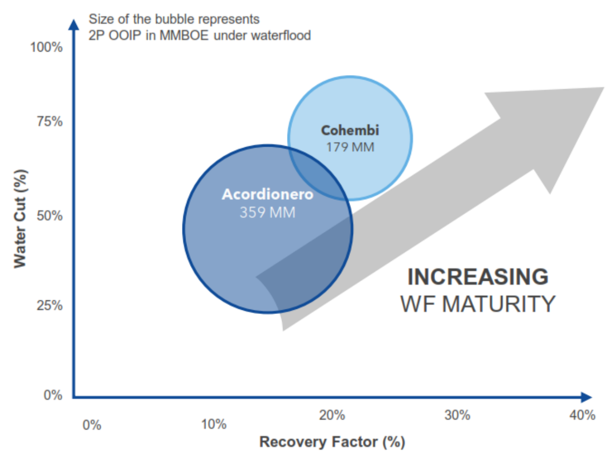
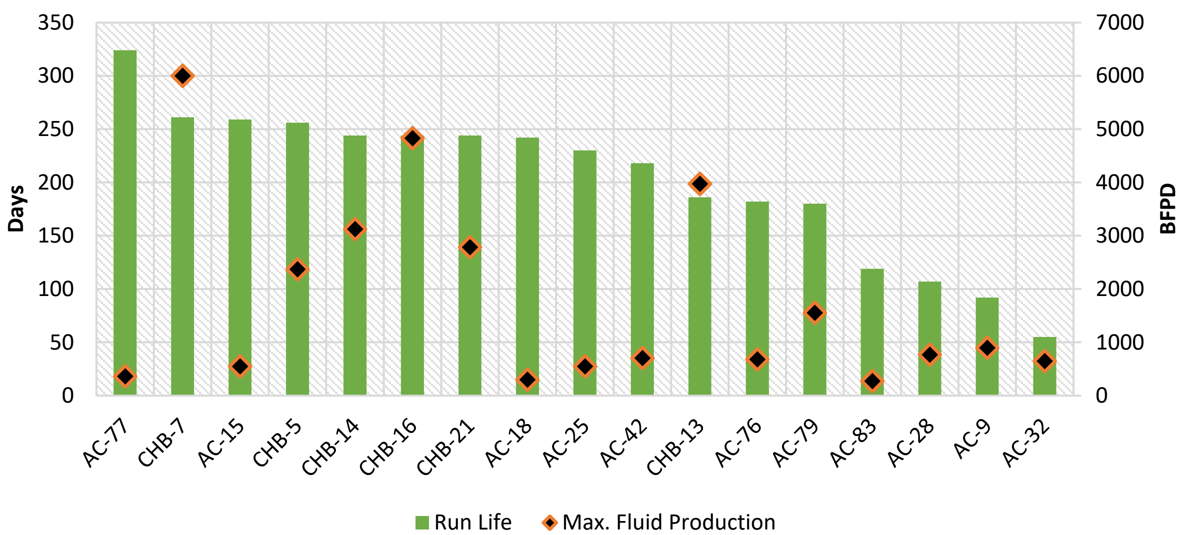
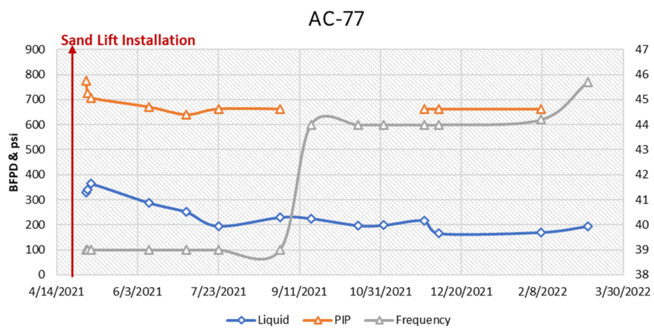
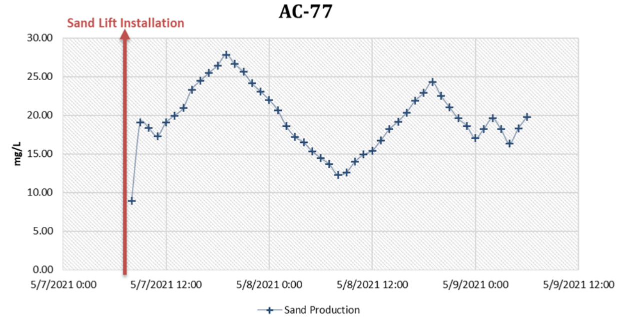


Figure 7 Waterflooding process







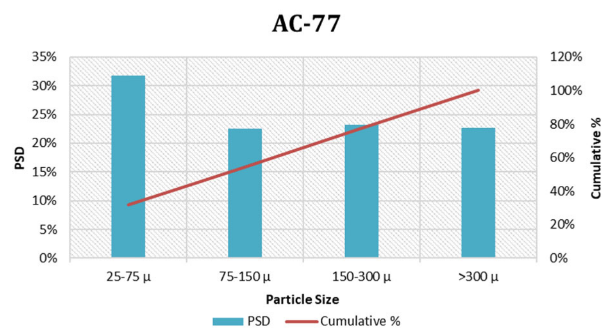


Figure 10. Monitoring and results for AC-77

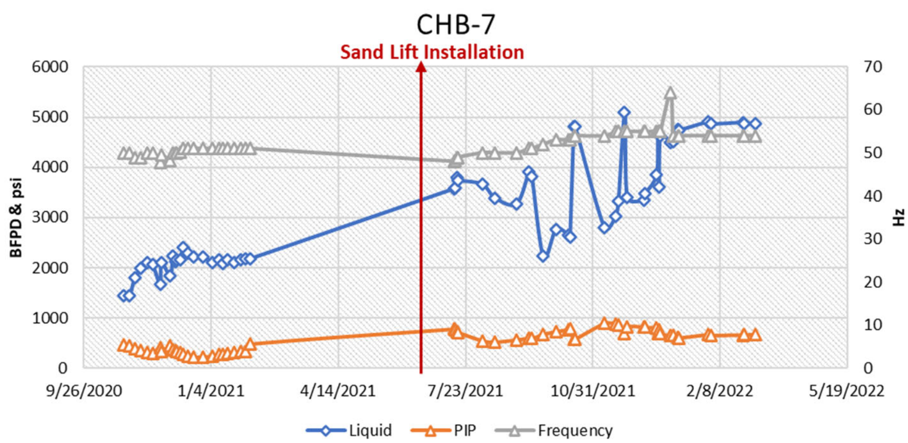
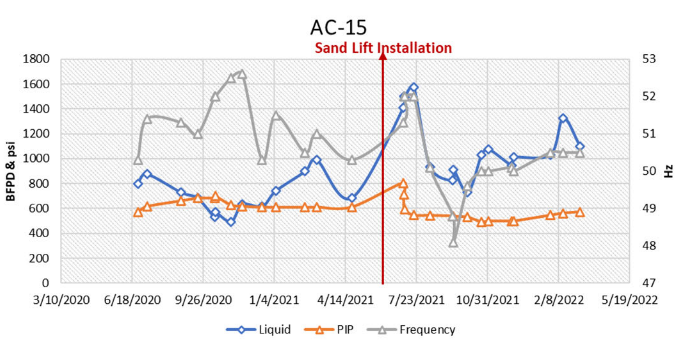
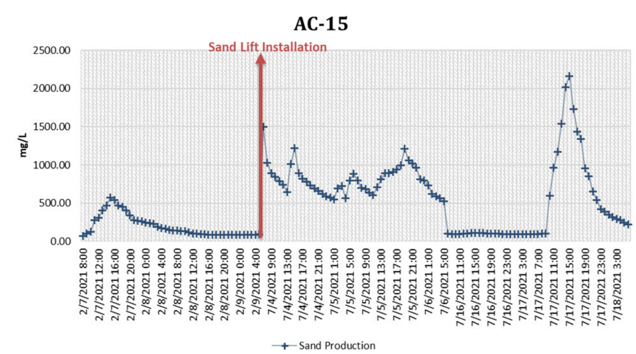
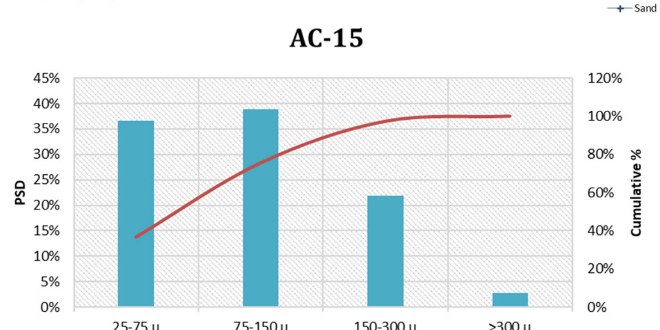
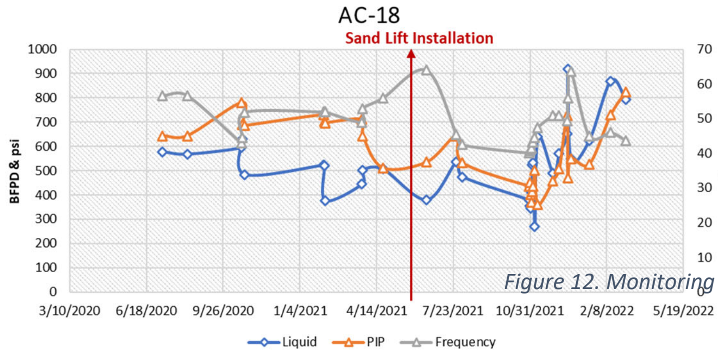


Figure 9. Monitoring for CHB-7









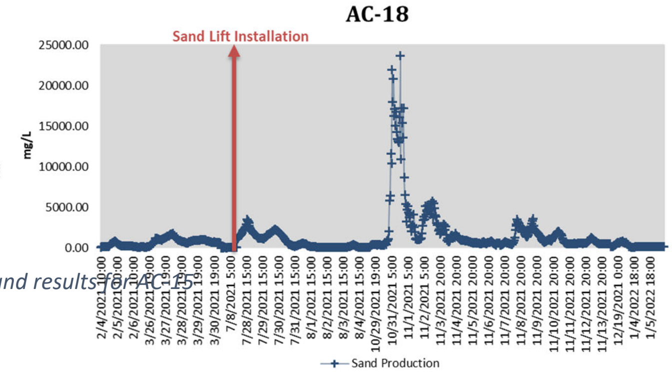


Figure 12. Monitoring and results for AC-15

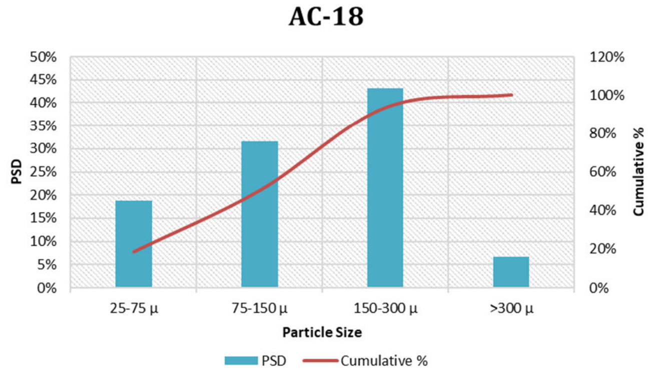
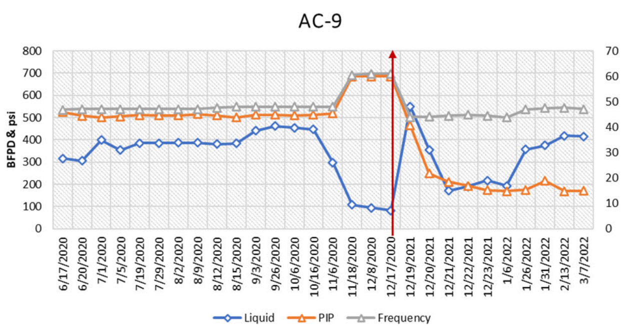
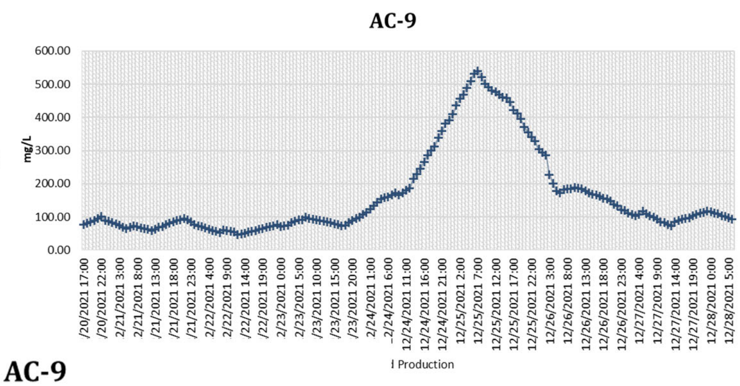


Figure 10. Monitoring and results for AC-18





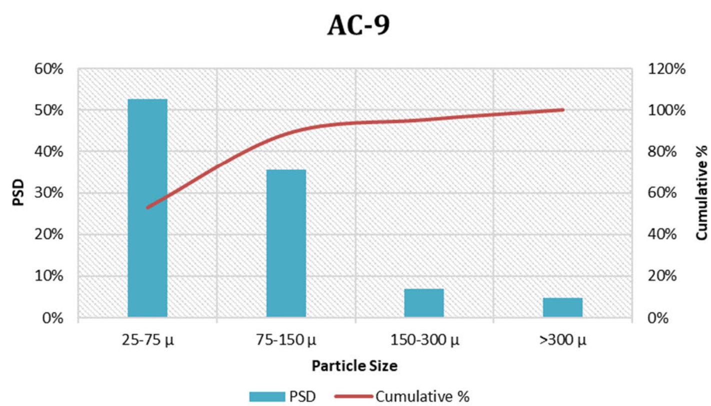
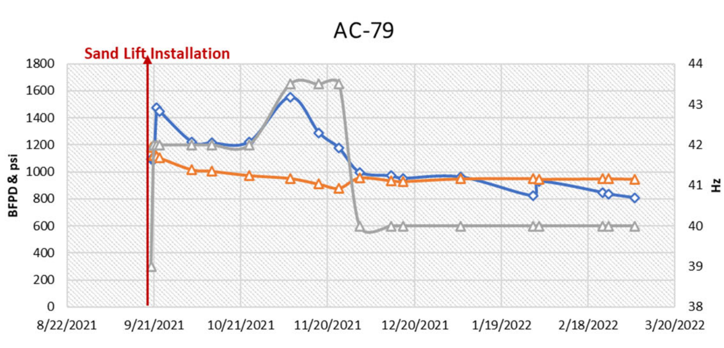
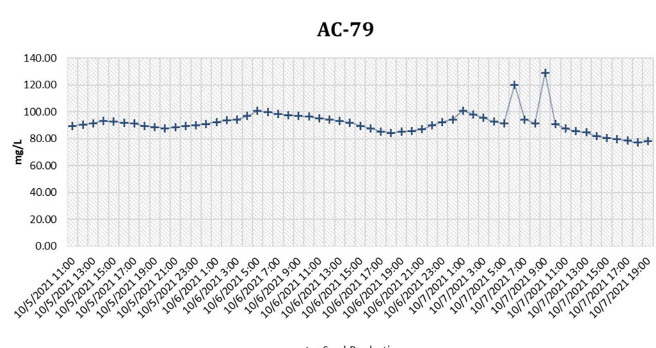


Figure 11. Monitoring and results for AC-9





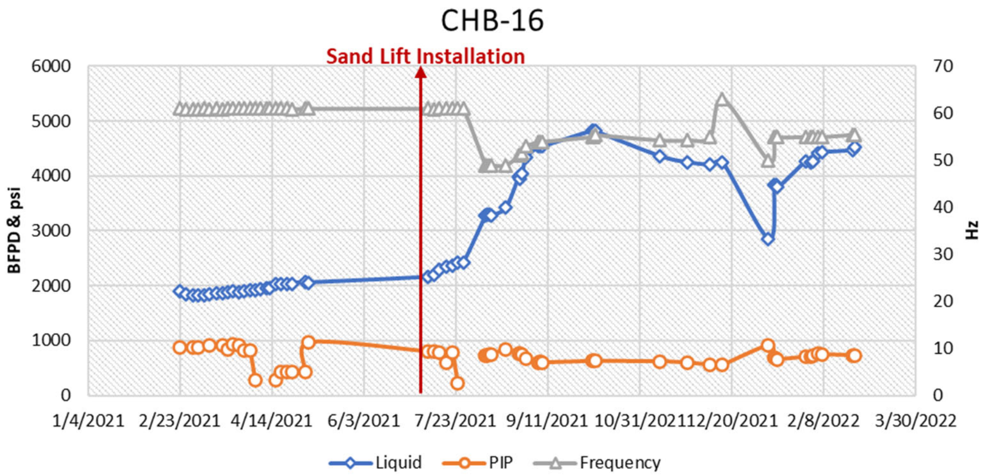


Figure 126. Well performance – CHB-16