Sand handling solutions through the use of Aggressive Geometry Progressing Cavity Pumps, "Fat Boy Project", La Hocha Field, Colombia

Hernadez, Nadia, Weatherford, Nadia.hernandez@la.weatherford.com
Delgado, Javier, Weatherford, Javier.delgado@ca.weatherford.com
Coronel, Jorge, Weatherford, Jorge.coronel@la.weatherford.com

Sinopsis

One of the major impacts on progressing cavity (PC) pump performance is sand handling. PC pumps can handle increased amounts of sand; but under certain conditions, this can have detrimental consequences on pump life, decreasing pump performance and increasing intervention rates.
What is the maximum sand cut a PC pump can handle? It is a very common question, but it will depend on different factors such as flow rate, fluid velocity, viscosity, water cut, grain size, grain density, well completion and PC system design. Most of these variables are reservoir characteristics, so they cannot be changed; but selecting a suitable PC geometry design can greatly contribute to PC Pump performance.
The effect of the PC geometry design—increasing cross section area, shorter pitch length, and aggressive helix angle while assuring the right fit and elastomer—can definitely improve PC performance for sand handling.
The study was completed in La Hocha field. This is an unconsolidated sandstone formation with flow rates between 100 and 300 bbls/d per well of 16° API oil. The "Fat Boy project" is the first in Colombia. It consists of improving PC pump performance operating with high sand cut and challenging conditions to result in fewer interventions, well services, production delays, and associated costs. The project started in mid-2012. Because of successful results, it has been expanded and now includes 85 percent of the wells in the La Hocha field.
This is all part of a combined effort looking for reliable and cost-effective solutions for challenging applications. This document will show the methodology applied by Hocol and Weatherford to deal with the high frequency of interventions because of pump failures and sanded-in wells. This document shows the statistics and consistent results from the past 2 years and validates the rationale for using aggressive-geometry PCPs. Adjusting the proper pump geometry has been the main contributing factor improving PCP performance during the past 3 years.

Introduction

The Hocha Field is located 100 km from Neiva in Huila (Colombia). The operation in this field started in November 2001, producing from the Monserrate sand formation at 3800 feet, with initial production on free flow of 700 BOPD and 16° API crude.
Progressing cavity (PC) pumps are used in a variety of artificial lift applications where their beneficial characteristics such as positive displacement, high efficiency, low internal shear rates, and pulseless flow provide benefits over other lifting systems. PC pumps can have a varity of geometries that determine their suitability for specific applications. To ensure optimal performance and run life, the pump geometry should be matched to the application.

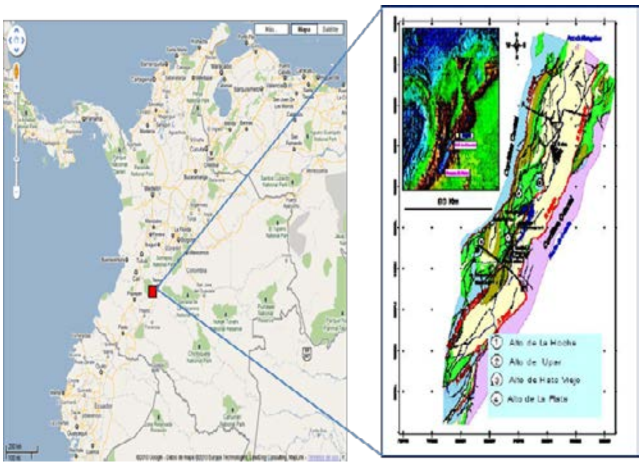

Figure1. La Hocha Field Location

Body Content

La Hocha Field Characteristics

Production Mechanism	Solution Gas Drive
Measured Depth	2500 to 3900ft
Initial Pressure (psi @ 250 ft SSL)	1380
Reservoir Temperature (°F)	115
Bubble Pressure (psi)	751
° API:	16.5 to 17.5
Petroleum Viscosity @ Res. Cond. (cp)	58
Petroleum Viscosity @ 100 °F (cp)	850
Water-Oil Contact (ft SSL)	1008
- Horizontal Permeability (md)	50 - 120

Table2. Reservoir Dynamic Model.

Background

Gas and mostly sand have been the main contributing factors to artifictial-lift system failures and high intervention rates. Based on that, PCP systems have become the most suitable option in order to control high sand rates.

- Most of the reservoir has no “matrix” resulting in sand problems due to nonconsolidated formation.
- High slurry formation flow (mixture of sand-oil-gas-water)
- High operational cost because of:
    - High frequency of PCP failures
    - Wells sanded-in
    - Broken rods and tubing
    - Surface sand handling, delivery, and transportation

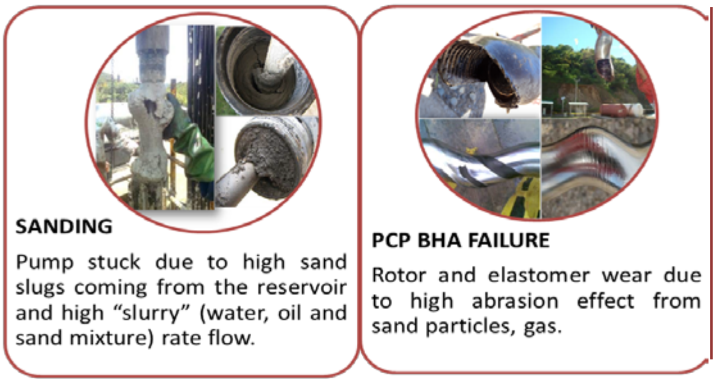

Figure 2. La Hocha Field Main Failures

Figure 3 shows an urgent requirement for an efficient sand handling solution since 2007. The increase in well interventions has been mainly the result of sand rates.

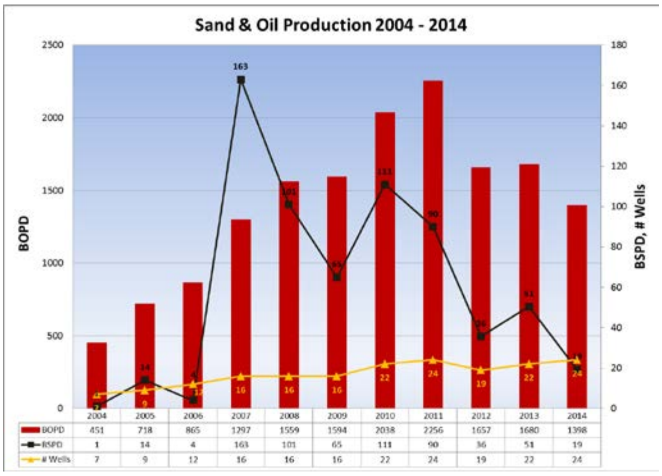

Figure. 3 La Hocha Field Oil Vs Sand Production

La Hocha Field Production Optimization Strategy

Looking to improve the performance and production optimization, the strategy consisted of determining the most common causes of failures .

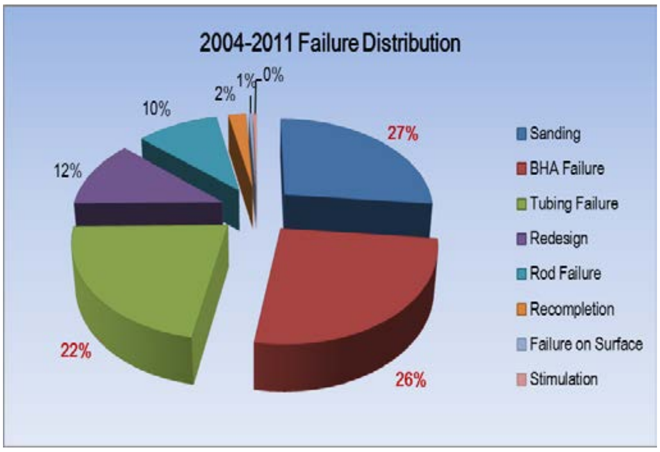

Figure 4. Failure Type Distribution

According to the historical field statistics, 74 percent of the failures correspond to three major aspects: sand handling, BHA failures, and tubing failures. The chart in Figure 4 shows the cumulative number of interventions and causes from 2004 to 2011.

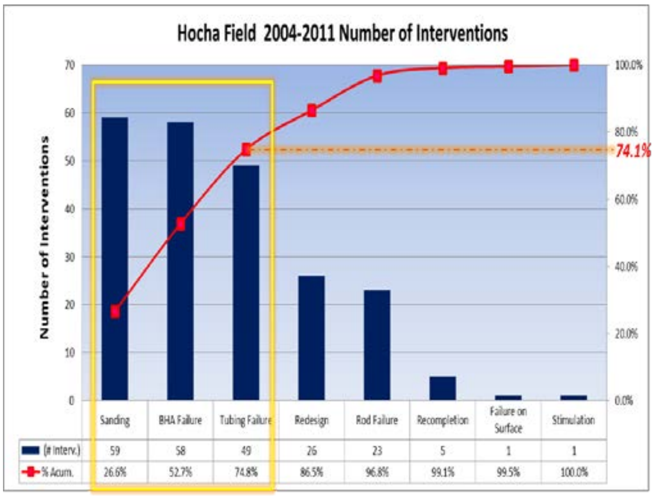

Figure 5. Field Intervention Acummulative Frecuency Vs Causes

In order to reduce the number of well interventions, the strategy was to focus on the two major causes, which represent more than 50 perenct of the failure cases. By improving sand handling and preventing BHA failures, the total average field interventions would be impacted positively. More than 50 percent of the failures correspond to the following issues:

- Sand bridges in the casing/tubing annulus, restricting flow to pump intake
- Sand settling on the PCP discharge, restricting flow to pump
- Slugs in the PC pump cavities, resulting in excessive torque
- Sand bridging in the tubing, resulting in excessive pump discharge pressures
- Sand accumulation in the flow line

NOTE: Sand production problems are significantly compounded with the production of free water.

CHOPS Technology

CHOPS (Cold Heavy Oil Production with Sand) is originally from Saskatchewan, Canada, and Elk Point, Alberta (120km NE of Lloydminster), where heavy oil cold production started in themid-1980s. Today there are approximately 3500 active CHOPS wells globally. Companies originally had the idea of “excluding” sand (gravel packs, screens, etc); most of these approaches failed dramatically. In the 1980s PC pumps started to be more accepted, and in the 1990s foamy oil and CHOPS became better understood. Now we have better understanding of the mechanisms for improving field cold production operations (workover tools, waste disposal, and PCP performance).

CHOPS is also known as Cold Flow, Cold Production, or Cold Heavy Oil production. Sand production causes dilatations and channels in the near-wellbore reservoir, which creates a growing zone of higher permeability (increased-radius well) that eliminates pore throat blockages from asphaltenes and fine minerals.

CHOPS techniques can handle sand concentrations of up to 80 percent, which typically decline with time to 1 percent. The purpose of the technology consist on continious and aggressive production of sand with heavy oil.. CHOPS operations are characterized by low temperatures, oil viscosities between 150 and 20,000 cp, initial sand cut of approximately 10 to 50 percent, and very good surface sand handling systems. CHOPS methods have improved greatly and have resulted in dramatic reduction in OPEX. Based on the challenging conditions in the La Hocha Field, HOCOL decided to implement CHOPS technology looking for continous oil and sand production to maximize rates and reduce intervention frequency.

Definition of Aggresive PCP (Fat Boy) Geometry

PC pumps are available in a variety of geometries to provide optimal performance for a variety of applications. One common application for PC pumps is the production of viscous, sand-laden, low-gravity heavy oil. It has been validated that pumps with aggressive PC pump geometries are well suited for such applications. These aggressive geometries feature short pitch lengths and low diameter-to-eccentricity ratios, which increase the pump cavity cross-sectional areas—all of which enables efficient flow of the heavy sand-laden fluid from one pump cavity to another.

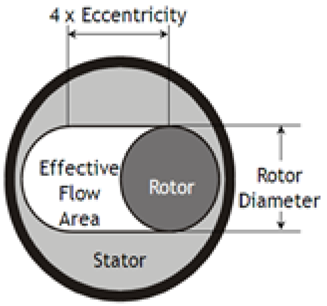

Figure 6. Rotor Profile

Because of their “aggressive” shape, these PC pumps require less pressure (head) to fill up the pump cavity. This results in improved ability to pump large particles and debris with continuous movement of heavy oil and sand, thereby increasing pump efficiency.

The larger cross-sectional areas of Fat Boy pumps can be seen in the chart in Figure 8, where similar conventional pump displacement capacity models are compared. Even conventional pumps with larger displacement capacity show shorter ODs than Fat Boy models.

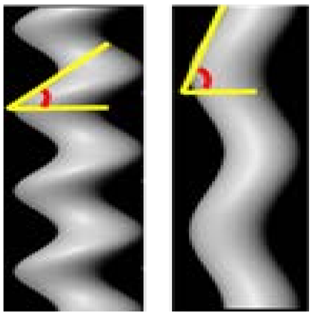

Figure7 Aggressive Vs Coventional Geometry

Pump Volume (m^3 per 100 rpm)	Stator Tube OD	Cavity Opening Cross-Sectional Area		Cross Sectional View*	Rotor Pitch View*
	mm	sq mm	% Increase		
7	75.0	477			
8	88.9	871	83		
13	101.6	1103	35		
15	90.0	819			
22	88.9	1006			
23	108.0	1452	44		

Figure8. Size Comparison of Fat Boy Vs Conventional Pump

The ***P*d/e*** *ratio* indicates the level of aggressiveness for PC pump geometries in that the smaller the value, the more aggressive the geometry. With the diameter *D* constrained, changing any of the other parameters will affect the aggressiveness of the geometry. For models with the same aggressiveness, the ***P*d/e*** *ratio* needs to be scaled in accordance with the diameter *D*. Therefore, the aggressiveness of any PCP geometry can be defined by the ratio of *P/D*d/e*. The ratio *P/D*d/e (*where P is pitch length*)* is used to classify pump aggressivenes level, defyning the range from 0 to **5** in the *geometry index* as the most aggressive geometry level.

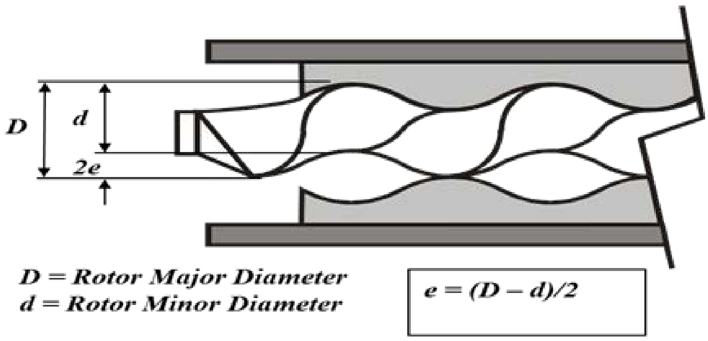

Figure 9. PCP Design Parameters

Mean Time Between Failure (MTBF)MTBF i predictes elapsed time between inherent failures of a system during operation. MTBF can be calculated as the arithmetic mean (average) time between failures of a system. The definition of MTBF depends on the definition of what is considered a system failure. Downtimes for routine scheduled maintenance or inventory control are not considered within the definition of failure.

The MTBF calculation is an indication of system reliability. The higher the MTBF number, the higher the reliability of the product. It can be ilustrated by the following equation: $\boldsymbol{iability = e^{-\left(\frac{Time}{MTBF}\right)}}$.

Candidate Selection Criteria

Looking for measurable and comparable results, historic data was evaluated. The project started evaluating candidates with high frequency of interventions due to sand and bottomhole equipment, with short run time. As was shown in the previous charts, there are several causes for well interventions in the field. The project was mainly focused on wells directly affected by sand and worn out pumps. That way the statistics were not impacted by other causes. Run life was considered to evaluate PCP performance for similar well conditons using historical data. The main parameter to evaluate PCP performance for this project is the Mean Time Between Failure (MTBF). It measures the impact of reducing well interventions and operational costs. Just using an average run life as the parameter would have included no challenging applications, old wells, and recently drilled wells.

The use of aggressive-geometry PCPs started in challenging candidates in 2012 (4 pumps); nowadays there are about 17 Fat Boy PCPs operating.

In the early production stage of the field, conventional PCPs were the main option, then charge PCPs were used, and by 2014, 85 percent of the PCPs were switched to Fat Boy aggressive- geometry PCPs.

Field Application Results

In Figure 10, Well 1 shows a high frequency of interventions and pump replacements. Different pump models (conventional and charge pump) had been installed in the past few years, and challenging well conditions resulted in 230-day maximum run lives. The Fat Boy PCPs currently installed have now been running more than 600 days under same production conditions. The following well intervention historic trendreflects a reduction of 4 interventions in the last 2 years.

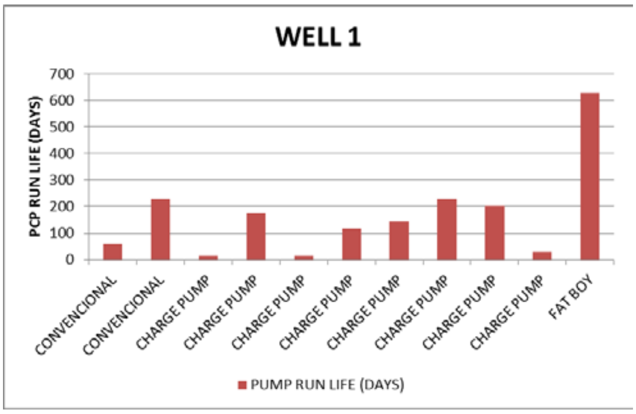

Figure 10. Well 1 Fat Boy Performace Vs Previous Pumps Installed

Wells 2 and 3 (Figures 11 and 12, respectively) were mainly affected by sand bridges, high torque, and excesive pressure at the pump discharge due to solids. The aggressive geometry of the Fat Boy PCP) improved sand handling performance, and the Fat Boy pump lasted longer than the four previous pumps installed in same conditions.

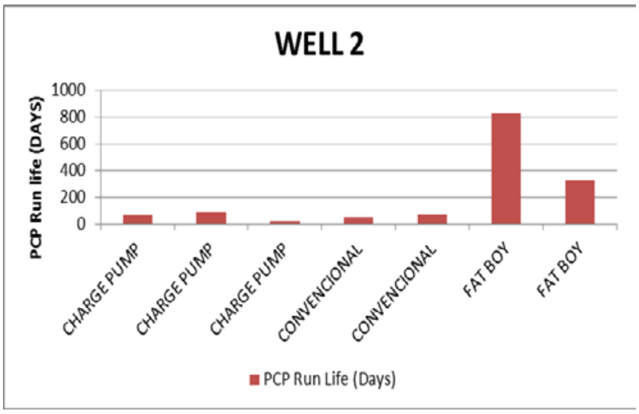

Figure 11. Well 2 Fat Boy Performace Vs Previous Pumps Installed

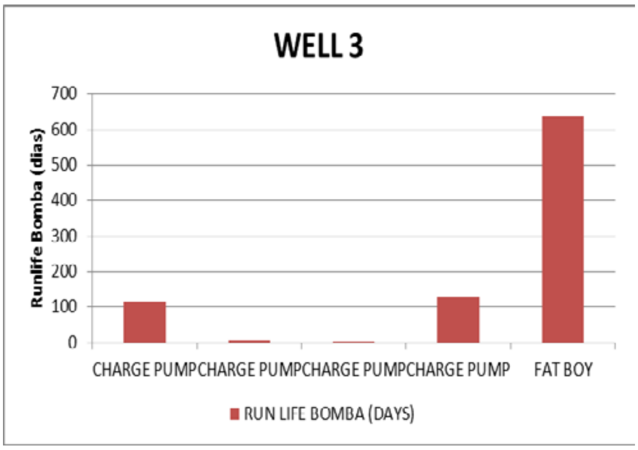

Figure 12. Well 3 Fat Boy Performace Vs Previous Pumps Installed

Sand production naturally decreases in most mature fields over time. Wells 1, 2 and 3 (circled in Figure 13) operated with aggressive-geometry pumps in the past 5 years under similar conditions to those in which the previous different conventional and charge pumps operated. In addition, operating conditions were also impacted by higher water cut and GOR (lower viscosity), becoming more challenging for sand handling.

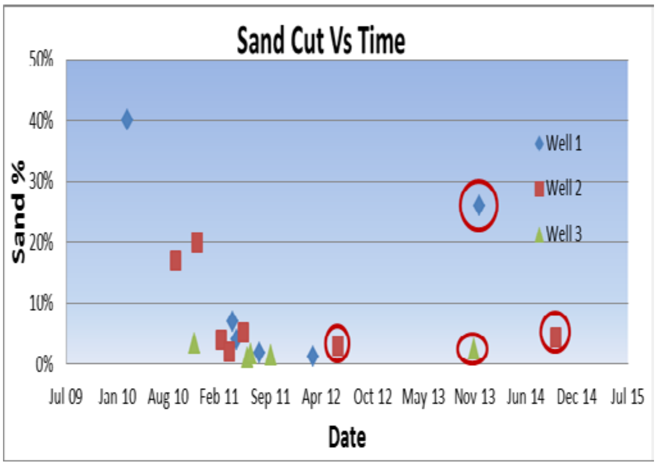

Figure 13 Historic Sand-Cut Meassurments for Wells 1, 2, and 3

Aggressive-geometry PC pumps are not just used for low rate wells; they can handle rates up to 750 bbl/d. When fluid production rates drop, sand handling also becomes more critical because lower fluid velocity reduces the capacity of fluids to carry solids to surface. This is where aggressive-geometry series pumps become more efficient and provide better results than conventional and charge PCPs.

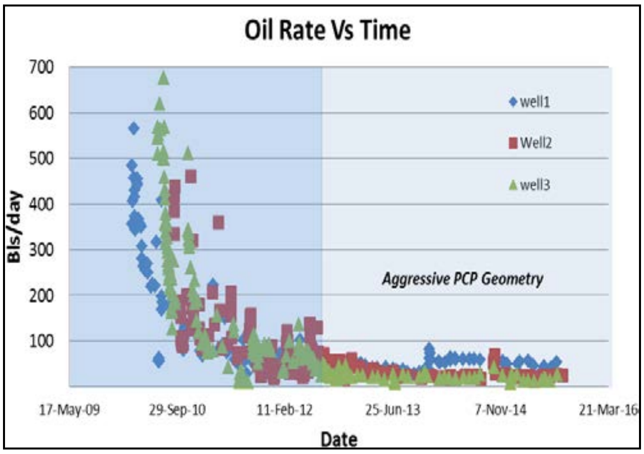

Figure 14. Forecast Oil Production Rates for Wells 1,2, and 3

Figures 13 and 14 show a common trend for oil field development; but for wells 1, 2, and 3, oil production declined more sharply than sand cut (%). Even when sand production decreased, the condition was challenging due to lower liquid production rates. Figure 15 shows how operational speed reduction combined with the aggressive geometry resulted in a more effective sweep per cavity, which in some cases resulted in increases in pump volumetric efficiency at lower speeds.

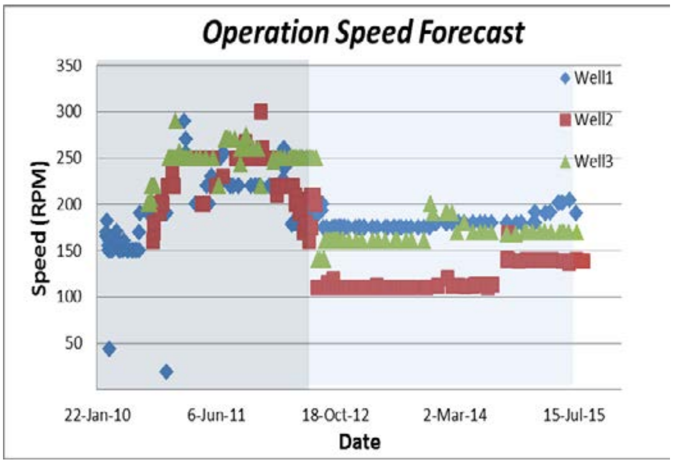

Figure15. Speed Forecast for Well 1, 2, and 3 Before and After PCP Aggressive Geometry

Figure 16 shows the MTBF on sandy wells and worn out pumps due to solids effect. Aggressive-geometry pumps (Fat Boy pumps) improved MTBF 75 percent over conventional PCPs and 60 percent over charge pumps. Aggressive-geometry PCP installation started in 2012, so MTBF statistics were calculated after 2013. Figure 16 includes the performance of 7 Fat Boy pumps and 13 charge pumps in 2013 and of 17 Fat Boy pumps and 3 charge pumps in 2014. The larger population helps to provide a more accurate number for MTBF calculation; otherwise, the MTBF will result in an unrealistic number.

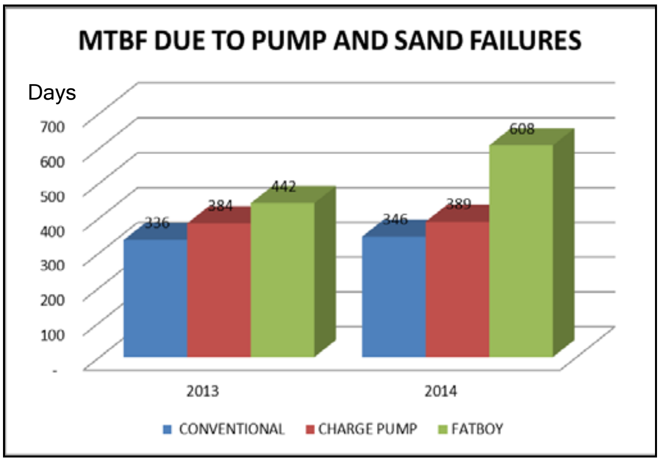

Figure 16. MTBF Due to Pump and Sand Issues for Each PCP Application

The MTBF for sand issues and PCP applications has been increased 38 percent from 2013 to 2014 in a 17-well population, which represents at least six fewer interventions due to solids handling.

Conclusions and Recommendations

Aggressive-geometry pump (Fat Boy pump) performance achieved greater results on sand handling in La Hocha Field, where PCPs represent 95 percent of the artificial lift population.

Lowering operation speed reduced rod/tubing wear to extend rod and tubing string life, which represents 50 percent of well intervention causes in La Hocha Field. It also has direct impact in power energy savings as an additional benefit for the operation.

The reduction in pressure required to fill pump cavities provides a better ability to pump large sand particles, thereby increasing pump efficiency, lowering speed, and resulting in longer PCP run times.

Once well production decreased, lower fluid velocity at intake minimizes the system capacity to carry out particals; greater cross-section area through shorter cavities facilitates sand transportation. Under these conditions, aggressive-geometry PCPs showed better performance than charge pumps and conventional pumps.

The use of aggressive PCP geometry in this sandy application improved MTBF, reducing intervention frequency, OPEX, and production delays.

In challenging applications it is always important to calculate the most accurate efficiency range for the application. Medium to soft elastomers are the most suitable for sand handling.

Intake sand blocking results in dry pump operation, overheating of the elastomers, and reduced life. The use of extra large and slotted tagbars delays pump burnout caused by lack of lubrication.

References

[1]Weatherford, Technical Bulletin “Fat Boy Model Identification,” TB-P126, WIP, Edmonton, AB, Canada, 2015.

[2]Data Center Science Center, “Mean Time between Failure Explanation and Standars,” Wendy Torrell, Victor Avelar, 2010.

.

Presentor Resume:

Javier Delgado
Petroleum Engineer Universidad Central de Venezuela (UCV) / 2004
Msc. Operation Management Universidad del Zulia (LUZ)/ 2009
Petrocabimas, Development Engineer Department Leader, Cabimas, Venezuela (7 years)
Weatherford, PCP application Specialist, Edmonton, Canada (5years)