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Challenging CSS operations in Colombia with high temperature all metal PCP

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ABSTRACT

The field subject of this paper carries heavy oil (11 to 13°API) at 90°F in vertical and horizontal wells (1900 to 4600 ft measured depth).

Thermal EOR used for this application is CSS (cyclic steam stimulation).

After steaming and soaking, the wells go natural flow, before shifting to artificial lift recovery, first with conventional elastomer PCP's (progressing cavity pumps), then with beam pumps after re steaming.

The challenges and limitations observed with beam pumps are gas locking, low efficiency and speed limitation at the end of the production cycle when temperature gets colder and viscosity higher.

For the demanding wells (more than 100 bopd in cold phase and 400 bopd in hot phase), the decision was made to proceed with the all metal PCP as per its flexibility versus variable viscosity production mode in CSS.

This paper presents the issues encountered with beam pumps then design phase of the metal PCP for this application, completion and operation feedback.

The key observations are lower down time, better behavior with gas, higher efficiency, extended production cycle with lower submergence, and, as a result, lower SOR (steam to oil ratio) and therefore economics benefits.

KEY WORDS

Production, Optimization, Artificial Lift, Progressive Cavity Pump, PCP, All Metal PCP, AMPCP, PCM Vulcain™, Steam Injection, Enhanced Oil Recovery, EOR, Cyclic Steam Stimulation, CSS, Colombia, PCM.

INTRODUCTION

Heavy oil reserves are mainly located in the western hemisphere, most of them in Venezuela and Canada. The willingness to maximize the recovery factor in these reservoirs required the development of diverse techniques which involves thermal EOR (enhanced oil recovery). More and more countries, including Colombia, have also ventured in thermal recovery projects to be able to produce these types of fields and maximize their oil production.

One of the more popular thermal recovery methods is Cyclic Steam Stimulation (CSS). It consists in periodic injection of steam into a producing well, alternating with a production cycle. Called also "huff and puff", CSS has as primary benefit of the process the true stimulation, reduction of flow resistance, viscosity reduction in the near-wellbore area. However, there are enhanced oil recovery (EOR) benefits of high-temperature gas dissolution, wettability changes, and relative permeability hysteresis (water flows into the reservoir easier than it flows out). Phases of each cycle begins with the steam injection, a soaking period and a production stage which starts at high temperature with very high water content, and as temperature and water cut decreases, higher production is obtained, until the well gets cold again requiring a next stimulation.

A key element on these recovery processes is artificial lift selection, which is required due to the high viscosity of the crude and typical low reservoir pressures. Pumping methods are more popular due to their higher mechanical efficiency and ability to generate more head at surface for delivery to the gathering station.

The main challenge when pumping hot fluids is the rather high temperatures often required. Cyclic Steam Stimulation (CSS) also adds the additional challenge of important variations in flowrate, downhole pressure, temperature, water cut. The dominant pumping technologies available are Beam or Jack Pumps, Electric Submersible Pumps (ESPs) and Elastomer Progressing Cavity Pumps (PCPs). However, all these pumps have their peculiar limitations for hot production: while Beam Pumps offer high temperature service, they are limited in the flow rate they can deliver. ESPs on the other hand, can handle high volumes of low viscosity fluids, but are still limited in terms of maximum operating temperature. Commonly used in CSS, Beam Pumps face problems also at the cold phase of each cycle due to the high viscosity of the fluid. If in addition there is presence of significant free gas a pump intake, both ESPs and Beam Pumps can suffer of gas lock issue. For the elastomer PCP, the limitation is operating temperature of the rubber (typically 100°C).

This limitation for PCPs ended with the development of the All Metal PCP (AMPCP). The development of this technology, which started in the mid-90s, expanded the temperature limitation of the PCPs up to 350°C (660°F), due to the absence of elastomer, but maintaining almost all the benefits of the PCP: cost effective, rotary positive displacement pump, low pump intake pressure, higher efficiency and simplicity.

This paper presents the first and the only successful field trial of this type of technology in Colombia and compares their operating performance to previous beam pump systems.

STATEMENT OF THEORY AND DEFINITIONS

Metal PCP Description

PCPs are known for their simplicity of design and operation. The heart of the pump is composed of two parts: the stator and the rotor (see figure 1). The stator has dual helical profile while the rotor (which rotates inside the stator) has a single helical profile designed to mate the stator profile. The rotating action of the rotor (sitting inside the stator) creates progressing sealed cavities from bottom displacing the fluid through each successive cavity and hence the pumping action. PCPs are non-pulsating pumps and will deliver a constant flow rate for a given rotor rpm.

In the conventional elastomer PCP as shown in figure 1, the part of the stator with the helical profile is made of elastomer and is glued to an external metallic tube. The rotor fits the stator with negative clearance.

For the Metal PCP (figure 2), the stator is fully metallic and hence able to withstand very high temperature. The metallic helical profile is produced by hydro forming as depicted in Figure 3. The stator is composed by 2, 3 or 4 elements of 9 ft long each, welded together. Here, rotor fits the stator with positive clearance. Both are specially coated for high temperature and wear resistance, but the rotor serves as a sacrificial element.

Figure 4 illustrates a typical Rod Driven (RD) PCP assembly as set into a well. The stator is usually run first with the production string. The rotor run thereafter and set into the stator. It is connected to drive head at surface with either standard sucker rod string, continuous (coiled) rod or hollow rod string.

AMPCP systems maintain the conventional PCP simplicity with some minor differences are found in the bottom hole assembly (BHA). An anti-vibration sub is used at the top of the stator, to minimize possible vibration caused by the eccentricity of the pump, which in this case is not absorbed due to the metal to metal contact. In the rod string, considering the high temperatures, if conventional sucker rods are used it is necessary to use high temperature centralizers.

At surface, it is also necessary to consider the use of high temperature components, where there is contact with the hot fluids: the integral blow out preventer (IBOP) needs to be equipped high temperature rams; also the seal at the drive head has to be designed for high temperature, typically a mechanical seal unit.

Advantages of the all-metal PCP are the following:

- Easy flow rate control (proportional to RPM)
- Easy to install, similar to conventional PCP
- High operating temperature range (up to 350°C or 660°F)
- Accept low or high viscosities
- Low NPSH i.e. operates with low bottom hole pressure
- Non shearing and no formation of emulsions
- No gas lock issues
- Easy initial start-up at higher viscosities

The metal PCP is designed presently to have:

- A life time of one year minimum (8000 h)
- Ability to handle sand contained in oil (up to 5%)

Development Status

Research effort for Metal PCP development through hydro-forming technology was launched in the mid-1990s by PCM and TOTAL. Several processes were tested for developing a full metallic stator. Only the hydro-forming process was successful in term of industrialization, performances and cost. By 2005, two industrial prototypes were produced and bench tested in hot conditions at the CERT, one of TOTAL research centers located in Gonfreville, France. The tests comprised:

- Performance tests at different RPM (max 400 rpm), delta P (max 135 bars) and temperature (maximum 200°C).
- Endurance test at 150°C at maximum operating RPM (400 rpm) & delta P (130 bar) for six weeks

The bench test showed encouraging results with overall efficiency reaching 65% (details of the bench test have been presented in a previous SPE paper (SPE 97796).

It also confirmed one of the strengths of the pump, which is its broad viscosity handling capability (an issue with rod pump and ESP too, as this is discussed here after). For higher viscosity, the overall efficiency is not very sensitive to delta-P but improves with RPM. For lower viscosity (high temperature), the overall efficiency decreases with delta P but is strongly improved by higher RPM.

Twelve (12) models in two (2) different series of the metal PCP have been developed since to cover a wide range of flow rates for heavy oil production. They are, in 4" Series: 80V660, 80V1000, 80V1350, 110V500, 110V750, 110V1000; and 4 1/2" Series: 220V500, 220V750, 220V100, 300V400, 300V600 and 300V800. The first number gives the maximum rate in m3/d at zero head at 500rpm, while the second number gives the nominal head capacity in meters of water equivalent. The pumps are rated to 350°C.

At the moment over four hundred (400) PCM Vulcain™ has been installed around the world, with maximum run life observed of 4 years. AMPCP has been proved in the different thermal recovery methods: steam flood, CSS and SAGD. An also cold production challenges have been successfully faced with AMPCP, like aggressive fluids.

Field Characteristics

The field subject of this pilot has the following characteristics:

- Heavy Oil 11.2-13°API
- Well depths between 1900-4600 ftMD
- Vertical and Horizontal Wells
- Thermal Recovery Method: Cyclic Steam Stimulation (CSS) or "Huff and Puff"
- Typical Cycle: Steam Injection, Soaking, Natural Flow (seldom), Production with Artificial Lift System (ALS)
- ALS used: Progressive Cavity Pumps at early cold production (evaluation phase) and Beam Pump or Sucker Rod Pump (SRP) during the steam cycles

Beam pumps performance is variable on every field of the area, showing difficulties in the particular one where this pilot was targeted as the productivity of the wells is higher (horizontal wells) and viscosity of the oil is high as well (11°API). Problems faced at beam pump units occurs at the middle and to the end of the cycle, when the well starts to cold down and water cut decreases, free gas appearing, having as result poor efficiencies and high fluid levels. This means the well potential is not achieved with existing lifting method.

DATA AND OBSERVATIONS

Candidates Selection

The well candidates for this pilot were selected looking to the problems found with the artificial lift system and where the well potential was not being achieved in particular towards the cold phase of the cycle. A total of 18 wells were analyzed in the field described, where the problems mentioned represent an improvement opportunity.

All the well candidates were simulated using the PCP sofware PCM Design™; comprehensive data of each well was used for the simulations: well surveys, completion data, fluid analysis, and production historical data. The designs for AMPCP in CSS evaluate two extreme conditions the system will operate at: hot production, where the critical aspect is the flowrate and pump speed; and cold production where the high viscosity increases the pump head and torque.

The main challenges found during this design stage for All Metal PCP application were:

- Wide production range (140-600 bfpd)
- Significant deviation (Dog Leg Severity) along rod string at all the well candidates (7.5-10°/100ft)
- Temperature / Viscosity (calculated at pump intake) changes: 130-350°F / 1-850 cPo
- Rod string / Power Supply Limitation: Well configuration is: 3 1/2” tubing, 1” sucker rod, and maximum power available at surface is 50 HP.
- Low submergence: In order to maximize the well production 100 ftTVD above the pump was targeted

Two (2) wells were finally selected for the pilot project, considering the PCM Vulcain™ and other components of the system would operate along the cycle within the recommended parameters:

- Speed range 50-300 rpm
- Maximum pump head <70% of pump nominal head
- Rod torque <80% of sucker rods rating
- Motor torque <80% of rated

Well A

- 9 5/8” Casing, 3 1/2” Tubing, 1” SR pin 7/8”
- Pump setting depth: 1490 ftMD, 1325 ftTVD,
- Deviation 56.3°, max. DLS rod string 7.7°/100ft
- 11.4°API
- Viscosities: 4265/1770/960 cPo @ 100/115/130°F
- Static bottom hole pressure (SBHP): 600psi
- Hot production: 600 bfpd (50% BSW) and FOP 400 ftTVD
- Cold production: 120 bfpd (11% BSW) and FOP 400 ftTVD

At figure 5 it is observed the production historical data (cold production and two steam cycles with beam pump). The well steamed with 7500 and 8000 MMBTU in the first cycles. Figures 6 and 7 show the performance of the beam pump previous to the AMPCP installation (dynamometer chart and fluid level). Between the middle and the end of the cycle, it is observed the difficulty faced with the beam pump, which needs to be operated at low speed (2.4 spm) as the pump efficiency is poor (42%). Because of this condition fluid above the pump remains high (620 ftTVD) and the well potential is not achieved.

Well B

- 9 5/8” Casing, 3 1/2” Tubing, 1” SR pin 7/8”
- Pump setting depth: 1456 ftMD, 1325 ftTVD,
- Deviation 55.2°, max. DLS rod string 8.2°/100ft
- 11.4°API
- Viscosities: 5345/2182/1315 cPo @ 100/115/130°F
- Static bottom hole pressure (SBHP): 600psi
- Hot production: 550 bfpd (50% BSW) and FOP 750 ftTVD
- Cold production: 120 bfpd (11% BSW) and FOP 370 ftTVD

At figure 8 it is shown the production historical data (cold production and three steam cycles with beam pump). Three previous cycles used 5900, 6500 and 5100 MMBTU of steam. Figures 9 and 10 show the performance of the beam pump previous to the AMPCP installation (dynamometer chart and fluid level). Between the middle and the end of the cycle, it is observed the difficulty faced with the beam pump, which needs to be operated at low speed (2.6 spm) as the pump efficiency is poor (47%). Because of this condition fluid above the pump remains high (387 ftTVD) and the well potential is not achieved.

Well Designs

The pump selected for both wells is the PCM Vulcain™ model **80V1000** (4" Series), which can achieve the production requirement with an expected speed range between 40-210 rpm. This pump model selected provides an excellent speed range looking to a long time operation, as the normal wearing could decrease the pump efficiency and production can be compensated by increasing speed with sufficient margin.

Pump head at cold production is 740 psi maximum, which is only 51% of maximum lift for this pump model. Maximum rod torque expected at cold phase is 730 lb.ft in both wells, representing 177 lb.ft at motor shaft. This represents for the rods a 66% of nominal torque for 1" sucker rod and 80% for the motor (6 poles). After analyze the deviation of both wells, there are important sections with high DLS (up to 8.2°/100ft), therefore contact loads were calculated with the design software and high temperature centralizers were included.

Test Procedures

The evaluation period for both wells consisted in a complete cycle, the stator was installed preceding the steam to evidence the ability to stand the injection at temperatures ranging 500-600°F. After complete the injection and soaking, the rod string was run in hole. After startup, the PCM Vulcain™ operated to complete the cycle until the well had cooled down and it was ready for the next stimulation.

Different aspects were evaluated during the cycle:

- Ability to stand steam injection and resume production
- Run life over one (1) complete steam cycle
- Volumetric efficiency along from hot to cold
- Optimization of the fluid over the pump

RESULTS

Well A Evaluation

AMPCP Stator was successfully installed in the Well A on July 2014, (see figure 11). After two weeks, for steaming (8400 MMBTU) and soaking, the well did not flow natural and the rotor and rod string was installed. The startup was smooth with values of torque very similar to expected. The well was maintained with 100 rpm, as the WHT rose to 225°F. After oil traces started to appear the well was speeded up to 225 rpm. Peak gross production was observed at 757 bfpd with a volumetric efficiency of 62%. After the surface temperature started to decrease, well optimization with the fluid level started, and the target of 100 ftTVD was achieved. At this point the maximum oil production was observed at 185 rpm and 463 bopd. The speed continue being reduced to maintain the fluid level, until arrive to 70 rpm as minimum speed at the cycle, and gross production decreased to 146 bfpd. At this point the volumetric efficiency got to its minimum 45%. Figure 12 shows the main parameters for the AMPCP along the production cycle: rpm, torque, oil production, FOP and volumetric efficiency.

No pump failures or downhole equipment failures occurred during the cycle; only a motor failure (reused motor) required a replacement, with minimum affectation to the well performance.

After the evaluation period, AMPCP continues to be used at well A during two more cycles. AMPCP at its 1st cycle (3rd cycle for the well), averaged 215 bopd, higher than previous two cycles with SRP. Two subsequent cycles averaged 151 and 154 bopd, higher than expected declination. No downhole failures were observed after 363 days of operation (running time) of the AMPCP. At Table 1 is calculated the accumulated production and averages per cycle. Figure 13 presents the historical production data of well A: early cold stage, two (2) cycles with SRP and three (3) cycles with AMPCP. It is also shown in the same chart the historical data of the fluid level before and during operation of the AMPCP. It is clearly observed the difference in fluid over the pump for beam pump (never observed below 580 ftTVD) and later with AMPCP (around 100 ftTVD).

Well B Evaluation

Similar to well A, at well B the stator was installed on September 2014 in the same way, followed by injection (8000 MMBTU) and soaking time. Figure 14 shows the drive head installed at well B with well A at the background. The well was started with similar behavior, torque values near to simulations, 100% of water.

Different to well A, pump speed had to be increased to 150 rpm as the surface temperature did not raise in the same way. At this moment the well was producing 438 bwpd with 58% of efficiency. After the water cut started to decrease, the speed was increased to 245 rpm, getting the peak of gross production with 636 bfpd, quantity never achieved before in this well. The efficiency decreased to 52%. Then the fluid above the pump targeted was achieved, and the progressive reduction of speed started, until the well got cold with 70 rpm and minimum gross production of 116 bfpd, 33% efficiency. Fluid over the pump was maintained low, but it was not strictly monitored and it got as low as 52 ftTVD, which is not recommended as it could accelerate the wearing and decrease the pump efficiency for following cycles. Figure 15 is showing the main PCP parameters during the cycle.

Despite the minimum submergence, no pump failures have been observed, only one downhole failure occurred when a centralizer spindle broke, not supplied by PCM.

The AMPCP continues running for two more cycles (total of 336 running days). Its first cycle was the most productive compared to the three previous cycles averaging 153 bopd. The second cycle was not as productive with a low average of 75 bopd, but the fluid over the pump was maintained as low as possible, meaning there was not an effective stimulation. After adding a tail below the pump to improve the heat transfer to the wellbore, the next cycle (not finished yet) improved the average production to 115 bopd, higher than the declination expected.

At Table 2 is calculated the accumulated production and averages per cycle. Figure 16 presents the historical production data of well B: early cold stage, three (3) cycles with SRP and three (3) cycles with AMPCP (last cycle not finalized yet). It is also shown in the same chart the historical performance of the fluid over the pump. Again it is observed how the beam pump could not lower the submergence below 240 ftTVD, but the AMPCP was able to decrease it even below 100 ftTVD with the consequent additional production.

DISCUSSION

Considering the aspects previously stablished to determine the success of the AMPCP in the wells A and B, here one by one analyzed:

- Both AMPCP were steamed through the stator, even three times at the moment. There is no effect of this operation in the pump performance, but simplifies the well services and minimizes downtime.
- Not only the PCM Vulcain™ was able to operate without pump failures during one cycle, but for a total of three cycles and both systems remain operative. 363 and 336 running days of both pumps already exceeded by far the expectation of the users.
- The pump efficiency observed after the initial wearing period was observed with an acceptable range for PCP (33-66%). Considering the safety precautions taken at the design stage, the low efficiency observed is easily compensated with increment of rpm without exceeding the maximum recommended for AMPCP. Well A showed better efficiency range (45-65%) compared with AMPCP at well B, however it was mentioned that fluid above the pump at well B had very low values near to 50 ftTVD, possibly meaning an excessive wearing during this lapse of poor lubrication.
- Well optimization is probably the most successful parameter evaluated, because this means additional production achieved. Minimum fluid level over the pump was easily obtained and maintained, reducing also operative costs. In both cases, the AMPCP produced above the declination curve expected, recovering the production levels even above the first steam cycle. As a consequence of the additional barrels, the steam oil ratio (SOR), a key indicator in all thermal recovery processes which basically indicates the quantity of steam used per produced barrel; is significantly improved as the injection remained similar but the production obtained is higher.

Additional benefits were found as per the simplicity of the system and the good performance of the mechanical seals. There were no leaking reported meaning also reduction in downtime caused by surface equipment, typical in the field with beam pump, in particular when hot fluid are being produced.

CONCLUSION

All-metal PCP is an artificial lift system that extends the range of application of PCP systems to high temperature conditions therefore its use in thermal recovery methods.

AMPCP provides a reliable solution to the several challenges faced in cyclic steam stimulation.

The precision achieved with the manufacturing process PCM Vulcain™ allows to operate with an acceptable range of efficiency, with several variable conditions as temperature, fluid viscosity, flowrate and water cut, also with important changes in the pump parameters as speed and head. This is particularly important in CSS.

Well optimization using all-metal PCP is very simple, requires minimum surveillance and personnel.

PCM Vulcain™ can operate with low intake pressure and does not suffer of gas lock.

It is possible to stimulate a well through the stator of the PCM Vulcain™ at temperatures of 500-600°F without damage or affect the posterior performance of the pump. This feature saves time and service costs.

In the case of study the parameters of the all metal PCP system were within the recommended operating values of each component.

The benefits of all metal PCP and production increments makes it an excellent option to optimize and improve this field and others with similar conditions where thermal recovery methods are used.

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NOMENCLATURE

°API: American Petroleum Institute gravity
°C: Celsius degrees
°F: Farenheit degrees
AMPCP: All Metal Progressive Cavity Pump
bbl: Barrels
BEP: Best Efficiency Point (or Performance)
bfpd: Standard Barrels of Fluid per Day (at surface conditions)
BHA: Bottom Hole Assembly
bopd: Standard Barrels of Oil per Day (at surface conditions)
CERT: Centre Europeen de Recherche et de Technique
cPo: Centipoises
CSS: Cyclic Steam Stimulation
DLS: Dog Leg Severity
Delta-P or ΔP: differential pressure
EOR: Enhanced Oil Recovery
ESP: Electr ical Submersible Pump
ft: foot or feet
FOP: Fluid Over the Pump or submergence
LP-SAGD: Low Pressure Steam Assisted Gravity Drainage
MD: Measured Depth
MMBTU: Million BTU (British Thermal Unit)
NPSH: Net Positive Suction Head
HP: Horse Power
lb.ft: pound by feet
P: pressure
PCP: Progressing Cavity Pump
Q: pump flow rate
RD: Rod Driven
rpm: revolutions per minute
SBHP: Static Bottom Hole Pressure
SPE: Society of Petroleum Engineers
SRP: Sucker Rod Pump or beam pump
SR: Sucker Rod
T: torque
TVD: True Vertical Depth
WHT: Well Head Temperature

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APPENDIX

The following relation defines the overall efficiency of the PCP (mechanical efficiency):

$$\eta_{overall} = \frac{\text{hydraulic powe delivered to fluid}}{\text{mechanical power at pump shaft}} = \frac{Q \cdot \Delta P}{T \cdot \omega}$$

While volumetric efficiency of PCP is given by:

$$\eta_{volumetric} = \frac{\text{Flowrate of liquid (standard conditions)}}{\text{Pump Validated Capacity} \cdot \text{Speed [rpm]}}$$

TABLES

Well A				
Cycle	ALS	Accumulated Production [bbl]	Total # Days	Average Oil Production [bopd]
5	AMPCP	16580	108	154
4	AMPCP	21337	141	151
3	AMPCP	27762	129	215
2	SRP	23349	142	164
1	SRP	39184	200	196

Table 1: Well A Oil production before and with AMPCP

Well B				
Cycle	ALS	Accumulated Production [bbl]	Total # Days	Average Oil Production [bopd]
6	AMPCP	10897	95	115
5	AMPCP	7782	104	75
4	AMPCP	19925	130	153
3	SRP	10020	105	95
2	SRP	20791	178	117
1	SRP	20032	141	142

Table 2: Well B Oil production before and with AMPCP

FIGURES

Figure 1: Elastomer PCP

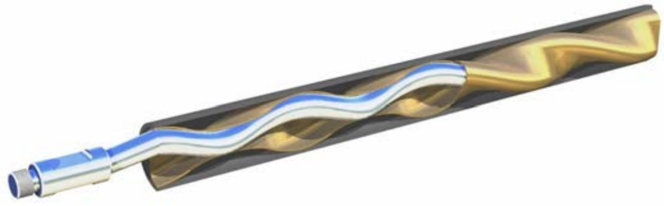

Figure 2: AMPCP - PCM Vulcain™

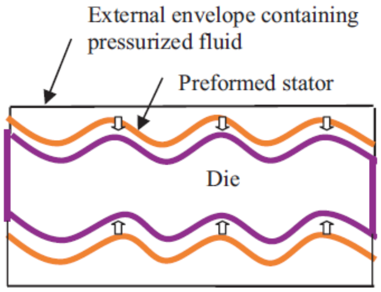

Figure 3: Hydroforming Principle

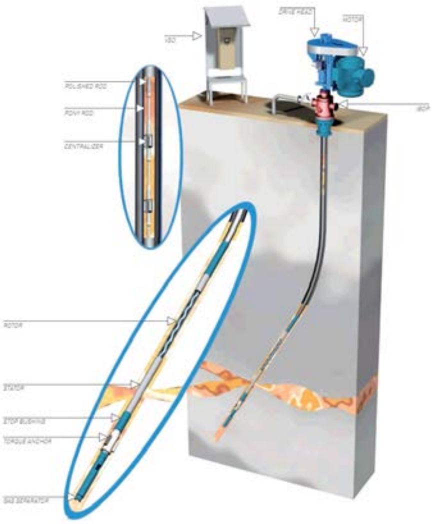

Figure 4: RD PCP System

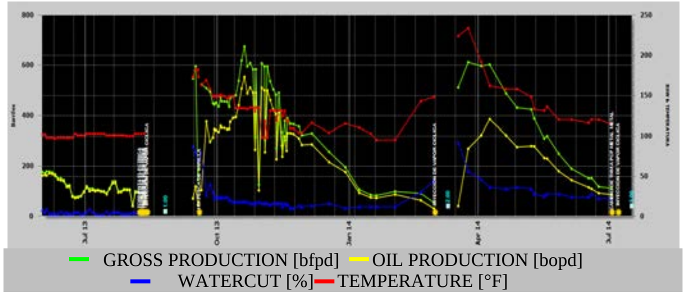

Figure 5: Well A Production Behavior before AMPCP

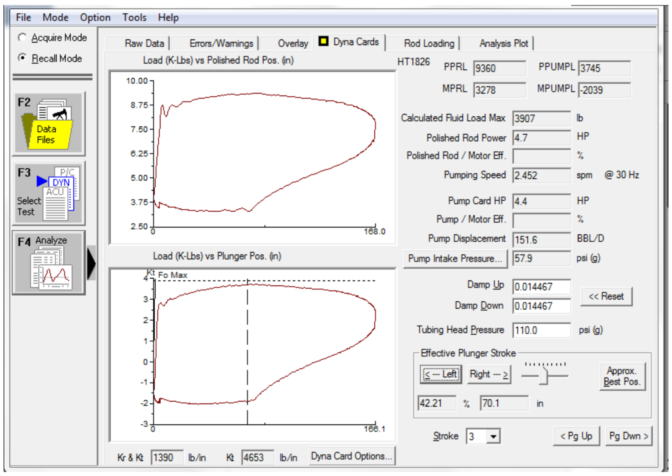

Figure 6: Well A Dynamometer Chart

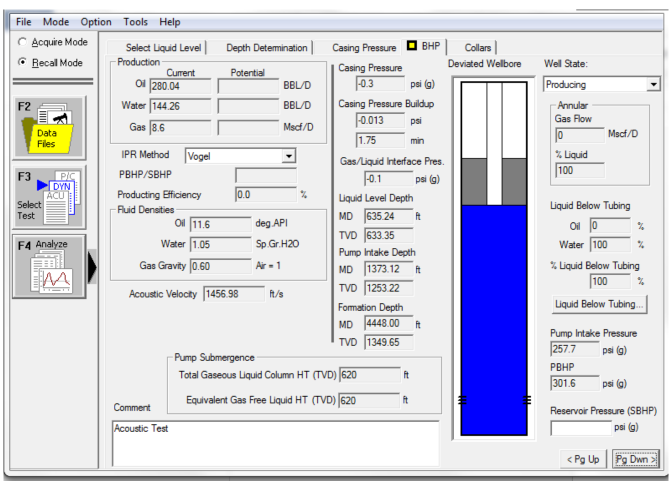

Figure 7: Well A Fluid Level before AMPCP

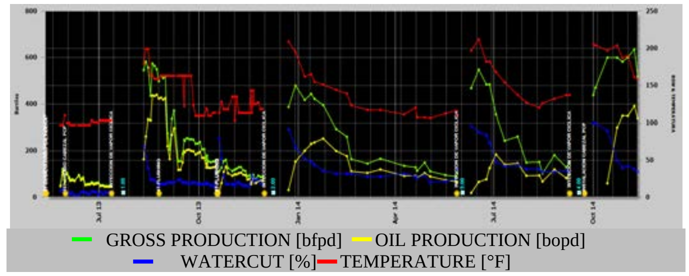

Figure 8: Well B Production Behavior before AMPCP

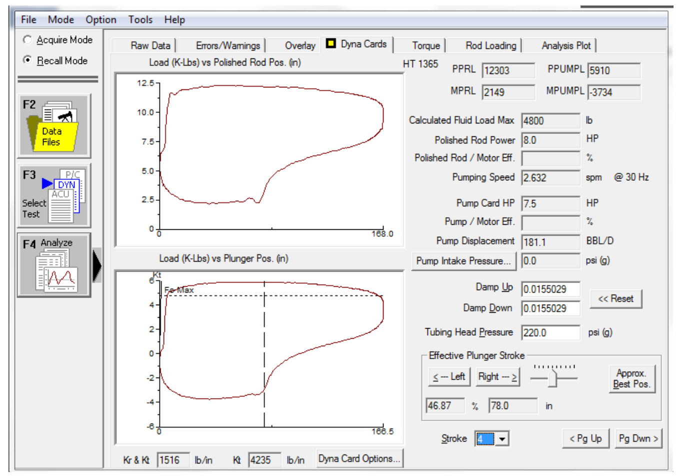

Figure 9: Well B Dynamometer Chart

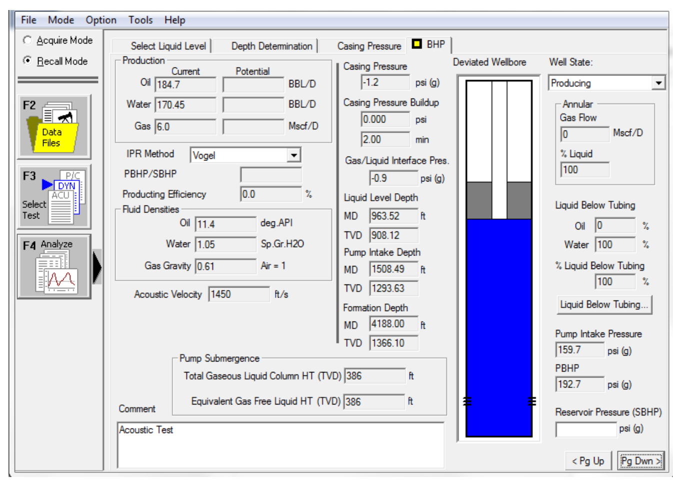

Figure 10: Well B Fluid Level before AMPCP

Figure 11: Running of PCM VulcainTM Stator at well A

Figure 14: Well B Drivehead (Well A at the back)

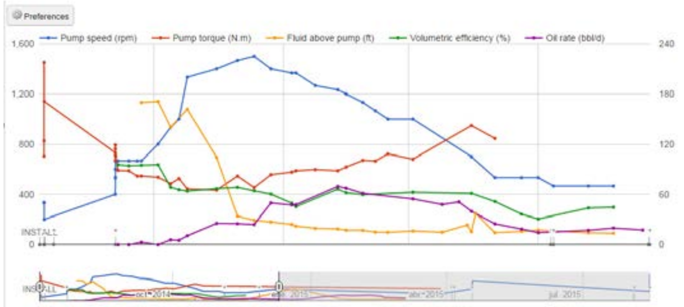

Figure 12: AMPCP Parameters at well A

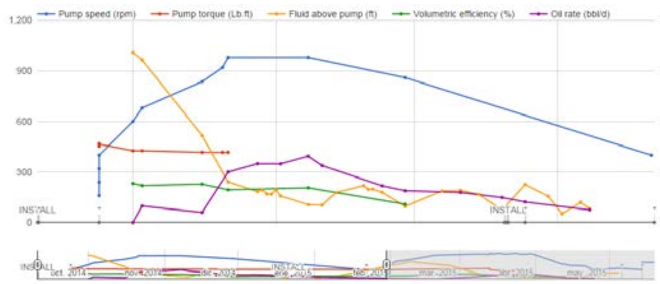

Figure 15: AMPCP Parameters at well B

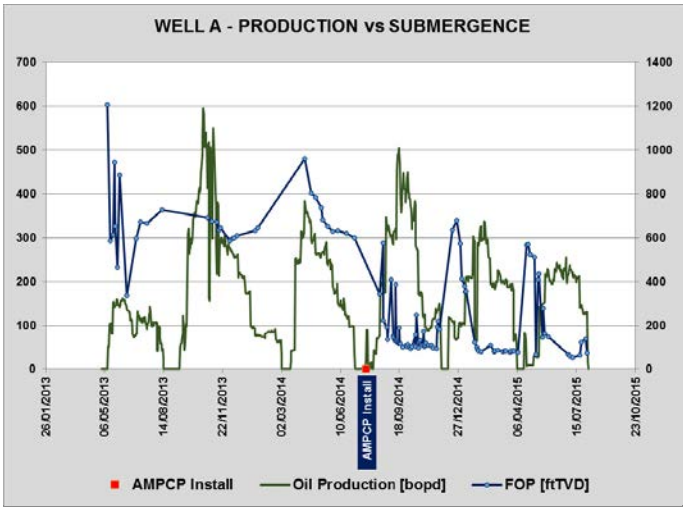

Figure 13: Well A Oil Production and Fluid Over Pump

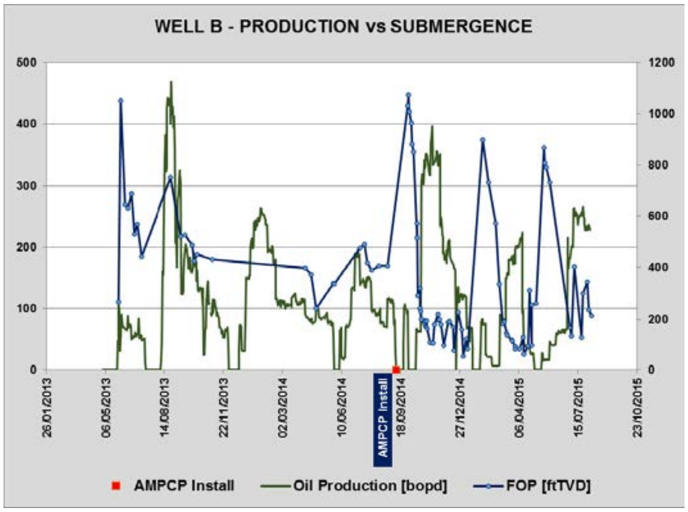

Figure 16: Well B Oil Production and Fluid Over Pump