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Case Study: Achieving Maximum PCP Run-life And Production In South America With Real-Time Digital Downhole Monitoring

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Abstract

The purpose of this paper is to discuss how downhole real-time artificial lift pump monitoring systems utilizing digital communications signals are an indispensable tool in managing reservoir production, equipment run-life and performance by acting as an "Eye into the Reservoir". Producers using digital monitoring downhole have expanded access to real-time well bore and pump information, which creates a competitive advantage in optimizing wellbore and reservoir performance. This paper will give an example of a major operator in South America utilizing variable speed controllers and monitoring their PCP pumps with digital downhole sensors. Without sensors monitoring the lift systems, the operator would not know what component downhole is causing lost production and if adjustments could be made at the surface to increase productivity.

One year following the installation of the PCP monitoring system, the operator reported a remarkable double-digit increase in production. This occurred by maximizing the pump output to match what the reservoir was producing into the wellbore and knowing exactly when a downhole assembly needed to be repaired or replaced and if a formation needed stimulation.

Introduction

Downhole real-time artificial lift pump monitoring systems are an indispensable tool in managing reservoir production, equipment run-life and performance by acting as an "Eye into the Reservoir". Producers using digital monitoring downhole have access to real-time well bore and pump information, in multiple zones, which creates a competitive advantage in optimizing wellbore and reservoir performance. “Seeing” the reservoir through downhole monitoring allows a producer to measure the economical effectiveness of past well intervention decisions, leading to better future decisions.

The value of implementing an artificial lift pump monitoring solution has the potential to increase, sustain or create revenue and/or avoid, reduce, or eliminate cost thus improving the bottom line. Recent estimates indicate that wells equipped with artificial lift pump monitoring systems can see a 10-18% increase in production. In order to realize these increases in production, a reliable, accurate, high-resolution digital downhole sensor measuring pressures, temperatures and vibration is required. An advanced surface data acquisition solution and qualified service personnel with many years of field experience is also important to any successful artificial lift pump monitoring systems.

Figure 1: Installation of PCP Monitoring System

Globally, the usage of PCPs in the production of oil and gas has grown tremendously. One recent study estimates that PCPs are growing at a rate of 15% per year. As this technology has gained acceptance; major operational and economic concerns still linger. Issues such as starving the pump or causing potential damage to the stator and other expensive pump components when the well is pumped off trouble many operators. For years, operators have been searching for a reliable and accurate way to control and improve their production. One way was to employ a pump-off controller (POC) or dynamometer card, or implementing an expensive pressure survey. The most common method to monitor the PCP is to monitor the amount of fluid level above the pump. By taking fluid level (shots) measurements and adjusting pump speed based on that fluid shot measurement at the time. This can be a very risky method of control and monitoring, because when the fluid shot is taken by the operator, is it simply not possible to know the condition of the well bore of other wells completed in the same communicating formation at the exact time the fluid shot is taken.

More recently, pump-off controllers have evolved as a method of protecting surface and downhole assets. While useful in monitoring motor torque, motor current, and fluid levels, pump-off controllers alone are limited in increasing production due to the lack of real-time bottom hole pressure data. Simply put, this may be effective as a short term measure on a per well condition, but does nothing for the analyzing and protecting the entire field due to the dynamics of the reservoir. The best way for operators to make pro-active decisions about the individual well and the entire field for monitoring and control of a PCP are through the use of downhole sensors that provide continuous monitoring of bottom hole pressure and temperature.

The importance of knowing your pressure

Understanding of pressure and pressure relationships is critical in well control. Specifically, bottom-hole pressure data is of primary importance in understanding the reservoirs performance, well conditions, and the lift system itself. It is vital that the understanding of pressure extends not only to the production of the reservoir into each individual well, but to the pressure differential between all the wells in the field, and knowing how the fluid is flowing through the formation.

Knowing the pressure of the fluid in the reservoir at the perforations and the API specific weight of the fluid in the wellbore will give an easy calculated fluid height in the wellbore. This fluid height value can be used as a process variable for a PID loop in the VSD controlling the speed of the motor to control the rate at which the pump produces while maintaining a constant fluid level. Once constant fluid level is maintained the operators can maximize field production and well system run life minimizing maintenance and work over costs.

The best way to know the correct pressure is by measuring the fluid level from the bottom of the well up. Using devices such as fluid shots, measuring fluid level from the top of the well down will sometimes give false readings due to emulsions of foam on top of the column of fluid. Emulsions have a much lower specific weight than the fluid in the formation. Using a fluid shot device will tell you where the top of the emulsion, not the location of the top of the fluid that can enter the pump without causing damage. The only way to derive true bottom hole parameters is through the use of downhole sensors installed as close to the perforations as possible, or as close to the pump intake as possible if the completion scenario will not allow the downhole sensor to be installed below the pump.

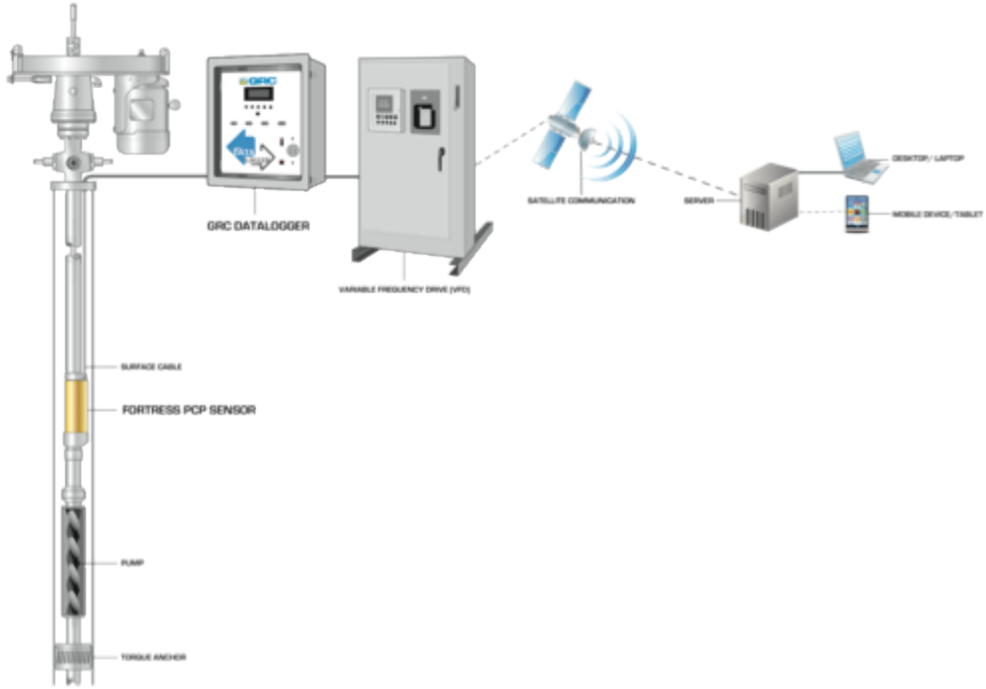

Figure 2: Typical Progressive Cavity Pump Monitoring System

As a global supplier of downhole sensors for permanent, memory and artificial lift applications, Sercel-GRC has witnessed first hand the value and importance of implementing a reliable artificial lift pump monitoring systems and has been extremely successful adapting to the exponentially increasing growth of technology. A client and major operator in South America began monitoring their reservoirs and Progressive Cavity Pumps (PCP) using Sercel-GRC's real-time digital downhole monitoring system. Previous to this time, the operator had not been completing their wells with any downhole monitoring systems. The operator was utilizing variable speed controllers set at 35 Hz for the first month of operation. As the operator's pumps began to self-destruct, the pumping flow rate would decrease below the reservoir production rate, causing the fluid level in the well bore to increase; therefore, not producing the well at its maximum rate. The operator could see that the production had declined but without sensors, the operator could not know if the decrease in production was due to the pump self-destructing or the formation choking due to increased skin. Even worse, the operator was not be able to see if the production rate and the fluid level were declining at the same rate or if the formation production was declining faster than the surface production ultimately resulting in well pump off. This critical information was unavailable using a Variable Frequency Drive (VFD) alone, which can only analyze the motor and change the well parameters after the VFD goes into underload, which happens after the well has already pumped off.

In order to achieve maximum pump run-life and reservoir production, the operator selected Sercel-GRC's Progressive Cavity Pump real-time digital downhole monitoring system to be installed on their PCP pumps. By combining the real-rime downhole sensor with the surface controller tied to the VFD on the well, the operator could begin controlling the production of the well based on the actual fluid level in the wellbore automatically using real time bottom hole pressure rather than a manually adjusted speed at the surface based on surface flow rate. If the frequency was manually controlled at the surface, the only time the flow rate at the surface will change is either in a condition where the pump is wearing out, or pump off has occurred. The VFD alone can detect these two situations with current underload and overload faults, but only detects it after the condition has already occurred. The downhole sensor will increase the production as the pump wears and prevent the well from drawing the fluid level down to the intake of the pump. This critical pressure data from the PCP monitoring system directed the pump to produce less when the pressure decreased and to produce more when the pressure increased, all while holding the fluid level constant. The operator was able to allow the VFD to determine the pump production automatically and on a continuous basis.

Understanding the Downhole Sensor

At the core of the downhole sensor utilized by the operator in South America is the capacitance transducer. The capacitance transducer is designed specifically for downhole oilfield monitoring applications and provides a rugged, and reliable solution over other types of transducers, while providing less drift. Data from the transducer is converted into a digital (or FSK) signal that allows for multiple sensors with multiple sensing parameters to be installed in the same well, while only utilizing a single conductor cable, minimizing the costs of the total downhole completion system.

FSK is an acronym for Frequency Shift Key. FSK modulation is utilized by the monitoring system to communicate between the gauge and the surface interface equipment. Digital FSK signals also allow for an increase data rate over traditional analog signals, multiple device addressing capability and redundant sensors for zone parameter monitoring. Further, digital FSK sensors have a unique digital address on a common communication cable that simplifies installation. With FSK Technology, the cable can be connected to the surface data acquisition unit and it will automatically detect the sensors downhole by their specific parameter address eliminating system configuration by a technician resulting in a simple plug and play device. (See figure 3).

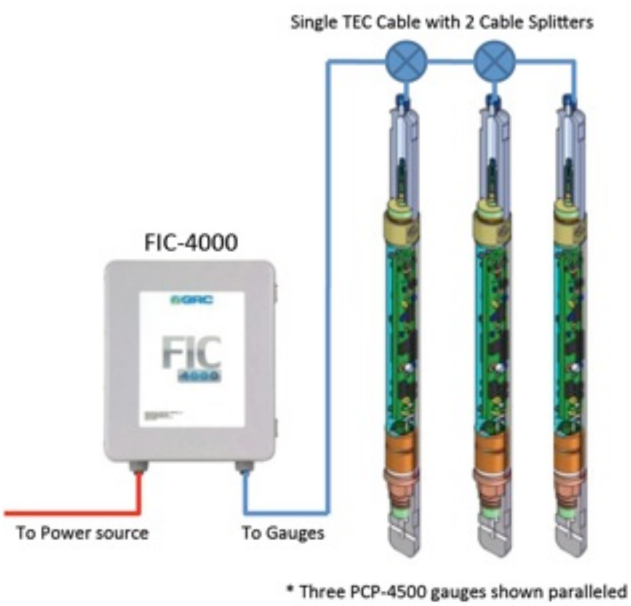

Figure 3: A single digital (FSK) surface interface board supporting multiple gauge communication with up to 6 communication channels.

The client in South America utilized a robust Remote Terminal Unit (RTU) with multiple analog and digital input and output options. The Sercel-GRC digital transceiver inside the surface data acquisition unit polls the downhole sensor, records and stores all the downhole pressure and temperature data onto a removable media on the RTU. Additionally, the RTU could capture, route and save a number of 3rd party inputs and outputs, digital and analog devices, along with multiple sensors in one well and/or multiple wells integrating them into one data collection system. This flexibility allows the operator the option to use a single surface data acquisition unit to monitor multiple wells and control multiple VFD's, resulting in cost savings in hardware and maintenance. The Data stored on the RTU is transferrable to the operators' remote sites via integrated telecommunications systems. With optional rechargeable batteries and/or solar/wind powered generator add-ons, the operator has the flexibility to deploy the surface data acquisition unit and RTU to remote locations with little infrastructure, and routinely does so. (See Figure 2)

Conclusion

With today's technology, in order to have a fully automated "Closed Loop" monitoring and control solution for an entire field of artificially lifted wells, the most important piece is knowing the flowing bottom hole pressure and fluid level, since they are always changing regardless of what is seen on the surface with monitoring motor speeds and production rates. Similar in ways to moving fluid from one holding tank (the reservoir) to another holding tank on the surface. Without utilizing a downhole sensor on the PCP pump, it is impossible to truly know what the bottom hole pressure is and know how much fluid is in the in the reservoir and at what rate it can be moved. Accordingly, it can be easily compared to writing checks and not knowing what the account balance is, resulting in an unfriendly service fee.

One year following the installation of the PCP monitoring system; the operator reported a remarkable 20%

increase in production. The operator has achieved maximum run life of their pumps due to the elimination of pump damage due to premature and sudden pump off. Additionally, the end-user now has the capability to run a “build-up test” anytime the pump is shut down from which the user can analyze the bottom hole pressure data to determine the skin on the formation-casing wall, analyze the flow regime in the formation, and detect any faults or boundary conditions that are in communication with the wellbore. This type of analysis was not possible from the traditional method of determining the pump-off control of wells with PCP pumps. Since pump wear, even with downhole sensors, cannot be avoided, the operator was able to efficiently schedule work-overs; knowing what wells needed to be recompleted or stimulated, and comparing historical pressure and flow rate data to see how long a pump would produce before it needed to be replaced.

Before the downhole monitoring system was installed, the operator’s motors were constantly operating at the same speed. Without making adjustments due to pump wear, reservoir choking due to skin, or reservoir depletion. The operator was able to quickly offset their investment to add the PCP monitoring system with the large production increases, longer lasting equipment and more efficient work over and stimulation scheduling. The Customer did not release the exact dollar amount in additional production and savings, but told Sercel-GRC that is was a “game changer” for their operation.
Since that time, Sercel-GRC service personnel have continued to successfully install many more PCP monitoring systems for this operator. The end-user is now able to predict with improved accuracy production efficiencies or inefficiencies and how their assets will deplete over time. Giving the operator a significant advantage in managing the multi-billion dollar asset; more precisely estimating how much fluid they can produce from the formation and being extremely proactive in preventing premature failure where unnecessary maintenance costs ultimately affect the net profit.