ENHANCING WELL OPTIMIZATION THROUGH ROD LIFT AUTOMATION

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Abstract

Automation of rod pumping systems has been a part of the oil and gas industry for over 65 years. Starting with time clocks in the 1950s prior to the invention of the pump-off controller in the 60's and variable speed drives in the early 2000's, the amount of technology available to not just control the system but also analyze it has increased and improved drastically.

With the increase in horizontal and deviated wellbores, the need for improved automation has also increased. Several examples of these factors to automate include high initial production rates, followed by a steep decline, gas slugging, high degrees of rod and tubing friction, and paraffin build-up. This paper will detail several of the automation packages and features that are available on the current market, the applications of each feature, and how they can be beneficial in preventing premature failures of the main components involved in a rod lift system.

Introduction

As the oilfield moves towards more data-driven approaches to well optimization, the opportunity for data collection and pump automation has grown. Rod lift automation began in the 1950's with the invention of the time clock (Lovelace, 2013). Figure 1 shows the general history of automation in the oil and gas industry. The time clock allowed for operators to set the pumping unit to run for a specified period before shutting down. In the early 1960's, the first pump off controller (POC) was invented. With improving technology, the variable speed drive was adopted by the industry shortly after 2000.

In even more recent years, many different automation options have arisen on the market with many new features being offered to improve the mean-time between failures and stroke-by-stroke optimization of the well. This paper will provide a brief overview of several common challenges that operators face when producing wells, several different methods that automation units use to measure pumping conditions, current features available to address those issues, and discuss several previously published studies in which automation was used to optimize production.

Production and Operational Challenges

Before examining the current automation units and features that are available, the downhole conditions and production challenges need to be identified. In many of the new unconventional plays, there are several conditions that can cause extensive problems. These are high initial production rates, followed by a steep production decline, slugging due to the geometry of the lateral, and high degrees of rod and tubing friction from deviated wells. Each of these conditions can lead to extensive problems with downhole and surface equipment leading to the need for automation.

Other issues that affect both conventional and unconventional plays are paraffin build up, low fluid levels, and decreased fluid inflow into the wellbore. As paraffin build up occurs, pump and rod loads will also increase and pump efficiency will decrease. As this continues, the production will begin to decrease due to the pump plugging off and other issues may arise such as fluid pound and pump sticking. Other issues that may occur are fluid pound, tagging, and gas interference. A final issue that occurs is that some wells are in remote locations and rather than sending personnel out on a daily basis to these locations, automation allows for remote monitoring of well conditions.

One of the ways these issues can be identified is through dynamometer cards. Several examples are shown in Figure 2. On the vertical axis, the dynamometer card shows the load on the well. On the horizontal axis, the position is displayed. When the pump is completely filling up and the well is operating smoothly, the card will show a rectangle. When issues start to arise, different shaped cards will form depending on the circumstances present. These dynamometer cards are recorded from the automation unit installed and there is some software available to interpret the cards. However, it is typically best practice to also have experienced personnel interpret the card.

Automation Units

Once the conditions that are present downhole are identified, it is important to understand the types of automation units and the different modes that can be used to operate them. The first type of automation is the timecard. This is the oldest method of pump off control that is used in the industry and has been phased out of most of the industry. The timecard operated similar to a timer. A set amount of time was placed on the timecard and the well would operate until the timecard reached zero and the unit would shut down. While this method was a step in the right direction, there was no additional control that could be used beyond the time placed on the well.

The second type of automation that is available is the pump off controller (POC). This is another older method, but is still commonly used across the industry. A pump off controller expanded upon the timecard by monitoring the load at the surface. Once the load falls below a predetermined set point, the well will shut down for a set period. Once the period has elapsed, the POC will start the well up again and run until the shut-down condition has been met again. This cycle will continue until adjustments are made by the operator.

The most recent addition to the automation market is the variable speed drive (VSD). While VSD's have been around since the 1950's and 60's, it wasn't until the early 2000's that they began to be adopted by the oil and gas industry (Lovelace, 2013). VSD's allowed for much more control than was previously available when using a POC. The VSD expands further upon the POC by monitoring the load present at the surface and instead of shutting the well down when the load drops below the set point, it enabled the unit to slow down and reevaluate load conditions. The next step in VSD development was the addition of an active front end (AFE) VSD (Lovelace 2013). For many of the locations, VSD's required more power from already overloaded power grids. Utility companies also observed that VSDs can increase harmonics levels on power grids. By adding an AFE, the power is drawn more cleanly from the grid, mitigating these issues.

These three pump control methods have enabled the industry to better control the pumps and provide the opportunity to better optimize production. While there may be several types of automation, the measurements used are typically done in one of two ways. The first, and most common method, is by installing a load cell on the unit which will directly read the amount of load that is being placed on the unit. Figure 3 shows the position of several components used in rod lift automation. The second, and more recently adopted, method is the motor torque analysis method. When using an automation unit with a motor torque analysis method, the power pulled from the motor is observed and calculations are done to examine the load on the pumping unit. This method eliminates the need for additional equipment to be installed on the unit, preventing possible outages with the load cell. Regardless of the method, an inclinometer can also be installed which enables not just the load being recorded, but also the position of the pumping unit when that load is occurring.

The final topic to be discussed in this section is several of the operation modes that are available when using the automation unit. These four modes are the single timer, single speed, dual speed, and optimized modes. The first mode, the single timer, allows for operators to set on-time and off-time set points. This is very similar to timecards; however it does allow for the operator to do this remotely and will continue to run on these conditions without having to reset the timecard every cycle. The single speed mode sets the unit the run at the same speed on both the upstroke and downstroke. Running at a single speed allows the operator to continually operate the pumping unit at the same speed and then turn off when pump off conditions are met. The dual speed mode allows for different upstroke and downstroke speeds. By operating at different upstroke and downstroke speeds, the rods can be allowed to catch up without buckling by slowing the upstroke while still maintaining the same overall strokes per minute by accelerating the downstroke. The final mode, the optimized mode, allows for the pump speed to be adjusted so that the downhole pump fill target is met. When the pump fill begins to fall below the set point, the unit may slow down to allow for the pump to properly fill up.

Solutions to Production and Optimization Challenges

Once the types of automation are known, the features that are available in the current market can be discussed. The first feature that is available is control of pump fill and loading.. When the well is falling below the set point for fill and load that the operator desires, the automation unit will send a signal to the pumping unit and shut it down for a set period. This can arise in situations where gas interference is present causing damage to the downhole pump and rod string. Pump loading may also be used to identify issues where the downhole pump may be stuck and the load on the rods exceeds the set point causing damage to the pumping unit. With many new units, the adjustment can now be made on a per stroke basis rather than on a timed scan of the unit. This adjustment is done through changing the stroke speed of the unit, either by slowing it down (as it is in most cases) or by speeding it up. An advanced version of this feature is the dwell pump off controller. When the pump fill remains below the minimum set point, the unit will slow down rather than turn off, preventing solids from settling out of the fluid. Both features are used to protect the downhole pump, rods, and pumping unit from a downhole pump falling through air and creating a shock load.

One of the next features that is available on the market is that some of the automation units can be installed and run without load cells present on the pumping unit. These units typically operate using motor torque analysis to identify high spikes in amperage usage indicating an issue with the well. One of the main advantages to using automation units without a load cell is that it requires less equipment to be installed and a more direct measurement of power required for operation. The primary disadvantage to using a unit without a load cell is the relative newness of the software. This newness leads to an unfamiliarity with the equipment for many installation crews leading to potential installation issues.

The third feature that will be discussed is the wireless access that is available and standard on many of the new automation units. With the recent push to operate safer and more efficiently in the oil and gas industry, wireless accessibility to automation units provides operators the opportunity to protect field personnel when on location. All that is required is the connection of the Bluetooth or wireless signal to either a laptop or handheld device and all the current information is available from within the company vehicle. While this does not completely eliminate the need for the field personnel to get out of the vehicle, it does reduce the time that the personnel need to be in close proximity to the wellhead and potentially dangerous situations.

Another feature that is currently available on the market is the auto rod friction detection. What auto rod friction does is it decouples rod friction from the pump fill. This provides the operator with a more accurate reading of both pump fillage and efficiency and rod friction from well deviation. When these features are monitored over time, it is possible to track when the downhole pump is becoming worn as the fill will begin to drop. As the wear grows, the pump fillage will continually decrease until it reaches the point where an operator deems it necessary to pull and repair the pump.

The next eight features are considered optional features and may not automatically come with all automation units. These features are rod load control, torque control, power limiting, auto gearbox lubrication, auto valve checks, maintenance mode, cold starting, and rod float control. Rod load control will automate the speed of the unit to limit the amount of loading the rods experience. By adjusting the pump speed, the loading on the rods is decreased and the life of the rods increases in turn. Torque control monitors the gearbox torque and when it exceeds the torque rating, the controller limits the output to protect the gearbox.

Power limiting can be used to reduce peaks associated with cyclic loads and improves energy efficiency. When operating a pumping unit at lower speeds, the gearbox cannot properly lubricate itself. The auto gearbox lubrication feature will speed the unit up to oil the gearbox for one or two strokes. Maintenance mode disables the limits and controls to diagnose a rod part or stuck pump. This feature needs to be used under proper conditions to protect the unit and rods from further damage. In the event of a stuck pump, the load will increase and can exceed the rating of the system. Auto valve checks can be done automatically now using the automation unit. The results are then graphed and considered in inferred production calculations.

The second to last feature that will be discussed is the cold starting limits. When a pumping unit has been shut off for a period, turning it on can lead to a shock load in the system. The cold starting will allow for the unit to start up at a preset speed, current, and torque to allow for the system to warm up. Once the system has reached that point, it will operate at the full preset conditions. When operating in heavier oils the rods can start to float and separate from the bridle. During the upstroke, the bridle will tag on the rod and send a shock through the system. Using the rod float controller, the unit will slow down if rod float is detected and prevent a shock load to the system.

Automation Case Studies

In the previous sections, this study discussed several of the issues that arise in rod lifted wells, the types of automation that are available, and some of the features that can be used to address the issues. One of the main goals of automation in the oil and gas industry is to provide the opportunity for the well to be optimized. This section will look at three case studies that have done pump stroke optimization and power usage reductions.

The first case study that will be examined was done in the Eagle Ford formation in South Texas (Elmer and Elmer, 2017). 20 wells were examined in the study and all were operating at various speeds and with different downhole conditions. In the study, the authors created the following performance criteria to determine the success of the study: pump fillage improving 8% or more, at least 5% fewer strokes per day without production loss, at least $100/month increase in energy savings, minimum rod load increase by 1,000 lbf or more, transition from intermittent pumping to full time operation, and increased production or production loss. For the pump fillage, the authors saw an increase exceeding 8% in 9 out of 20 wells. The 5% daily stroke reduction was successful in 8 out of the 20 wells and 6 out of the 20 wells transitioned from intermittent pumping to full-time operation. Only 8 of the 20 wells had power metering available and six of the eight exceeded the $100/month in energy savings with three exceeding $200/month. 12 out of the 20 wells saw the minimum average rod load increase by over 1,000 lbf. Overall, the authors determined that through pump speed optimization, the operator was able to free personnel from data analysis while doing a better job of maintaining pump fillage.

In the second study, another operator in the Eagle Ford analyzed 550 wells using sucker rod pumping systems and VSDs in the basin (Clark and Malone, 2016). In this study, the authors examined their production practices and shared lessons learned. Throughout the paper, the authors examine extensive data collected using the VSD system and failure analysis. Their final recommendations for variable speed drives are: intelligent VSDs are required to manage inflow variability, decline, and gas interference, proper configuration of VSD to operate in gaseous fluid, and connect the VSD through enterprise monitoring software.

While the previous two case studies examined both lessons learned through sucker rod pumping and approaches to optimization, the final case study will examine the effect that VSDs can have on energy savings. An operator in the Permian Basin performed a study on one of their wells and determined that energy efficiency could be improved by more than 25% by switching from the company's standard POC to a VSD (Wilke & Lile, 2016). According to the article, peak demand for electricity in the Permian Basin has increased more than 40% from 2010 to 2016. The well was run on the standard POC at a rate of 7.1 strokes per minute for 24 hours. After the 24-hour period, the operator installed the VSD and ran it at the same rate for an additional 24 hours. After the 48-hour test, the standard POC had used 236.8 kilowatt-hours and the VSD consumed only 175.4 kilowatt-hours. This reduction indicated to the operator that an additional 25 to 30% reduction of power usage could be reached in their wells.

Conclusion and Summary

Overall, this paper has examined the downhole conditions and operational challenges that may be present in a well, the types of automation units that are available on the current market, several of the possible features that can be used to help address the challenges that arise, and three case studies showing the potential applications of automation. By beginning to understand the features that are available and their applications, optimization and failure reduction in a well can begin.

References

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Figures

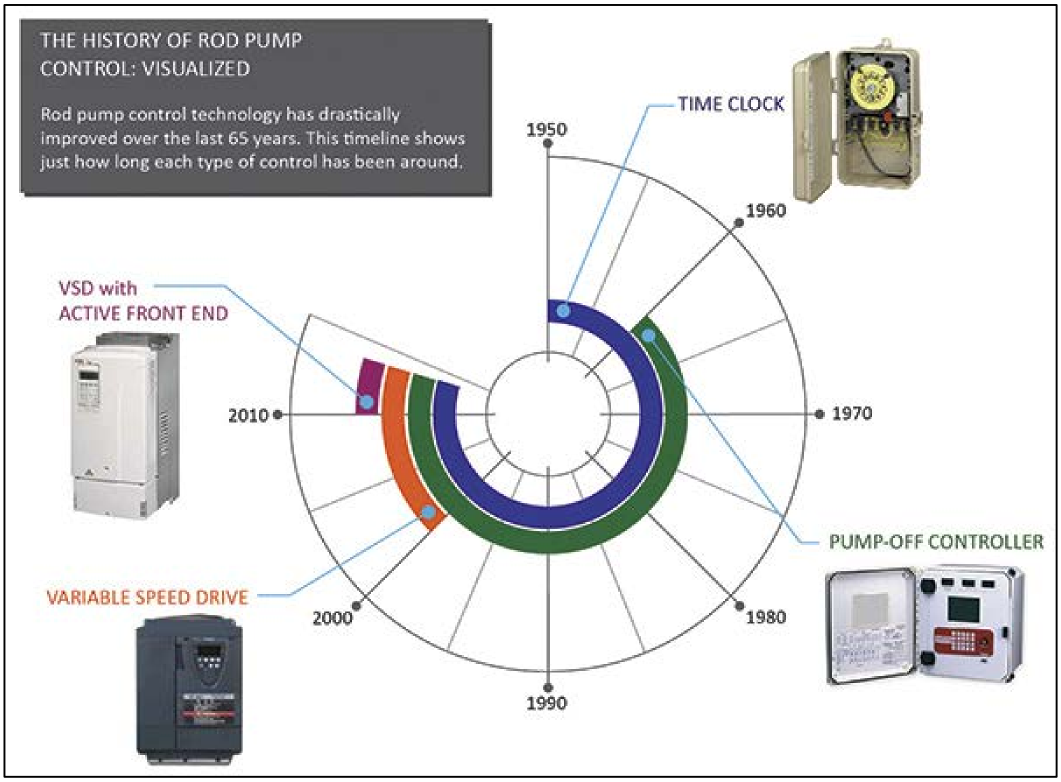

Figure 1 shows a general outline of the history of automation. Source: Lovelace, 2013

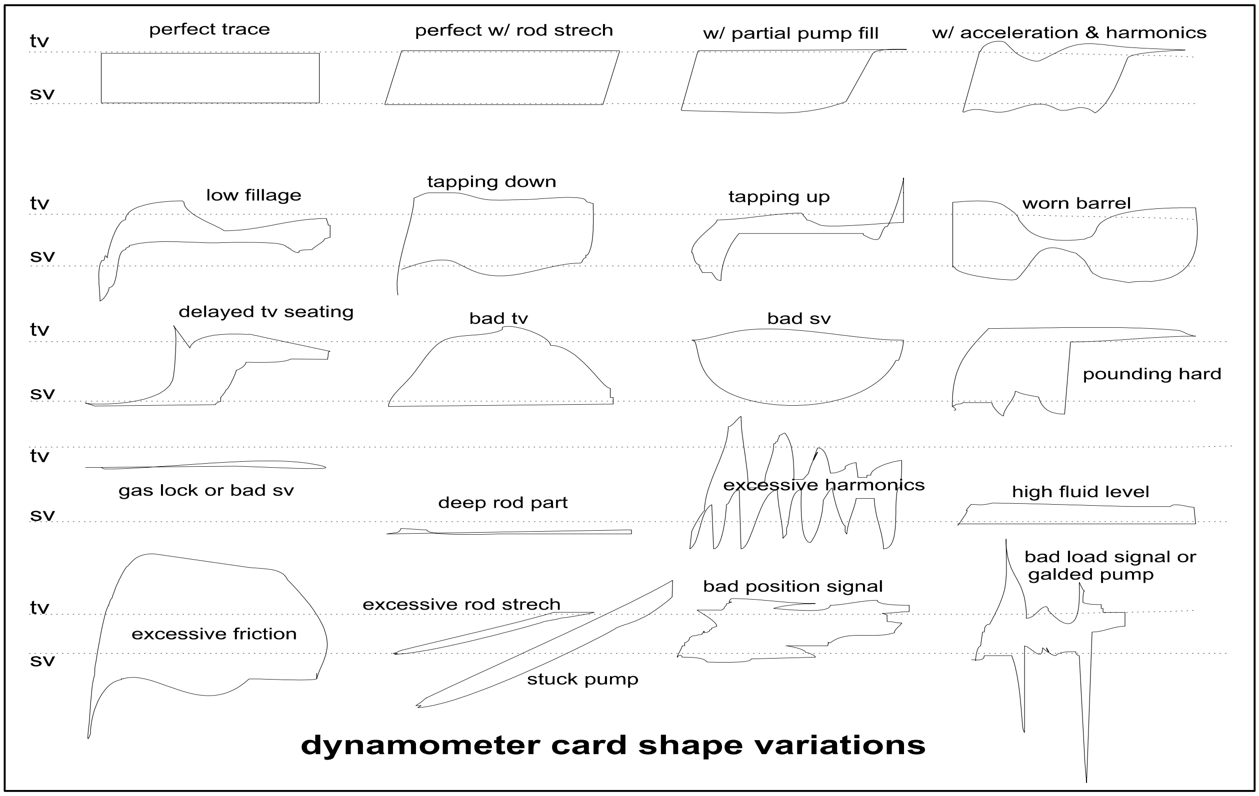

Figure 2 shows several examples of different dynamometer cards

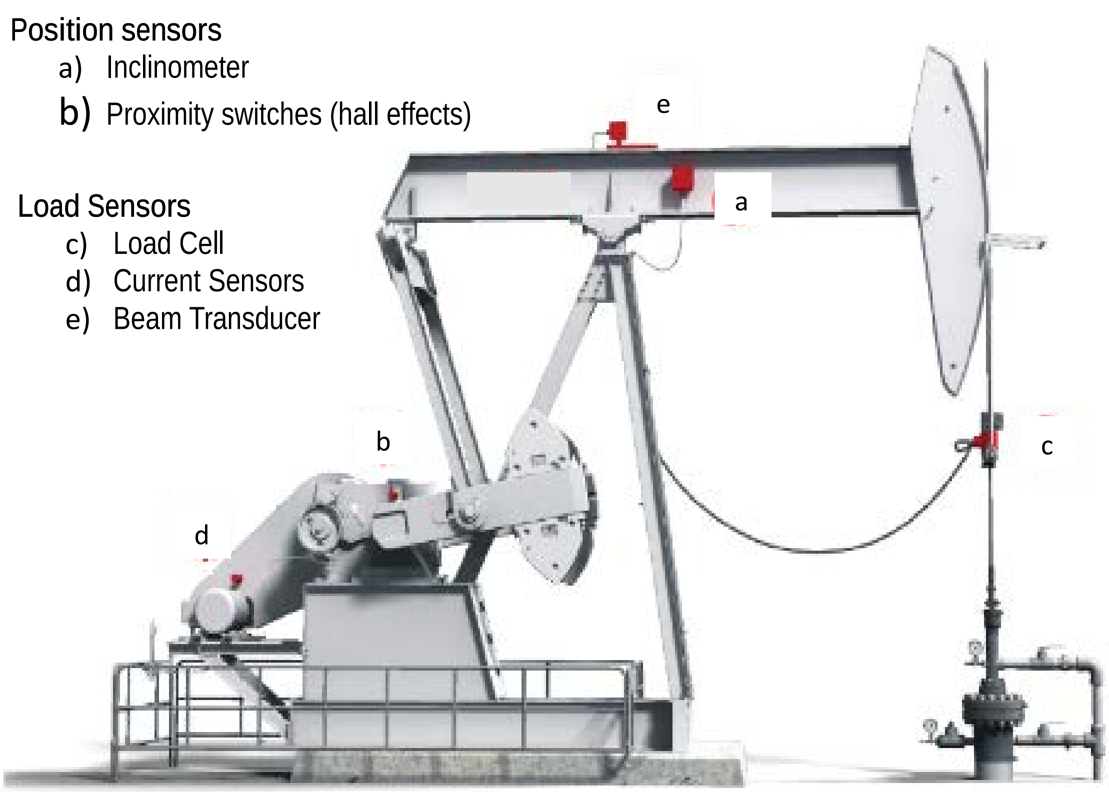

Figure 3 shows the locations of several components on the pumping unit