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An Innovative Approach to Increasing PCP runlife

Julian Cudmore (Zenith Oilfield Technology)

Abstract

Damaged elastomers are considered one of the most prominent reasons for production loss in a PCP lifted well. There are various documented reasons relating to this and this abstract will focus on incorrect position of the pump rotor inside the stator.

A low set rotor may bind on the tag bar causing elastomers damage due to excessive heat, whilst a rotor set too high will reduce pump performance and runlife.

A space out of the rod string is conducted during final stages of installation to set the pump rotor in the optimum position. The final position of the rotor relies on accurate calculation of rod stretch due to rod string and rotor weight, expected axial loading from the pump during operation and thermal expansion of the tubing relative to the rod string. It can be considered that the accuracy of the space out is dependent on the ability to see effects of weight loss due to the rod string, versus axial load due to the friction of the pump stator when pulling back from the tag bar. It can also be considered that the axial loading during operation is not constant and that the rotor position will change with changing fluid properties and back pressures. Other phenomenon such as twist (wind up) in the rod string and changing pump rotational speeds will also contribute to a non-optimal rotor position and decreased operational life of the pump.

Another common cause for workover is rod breakage. Rod breakage will occur if excessive torque is applied to the rod string. Although surface torque is often monitored rod breakages are still a common occurrence due to fatigue through rod tubing contact, loose couplings tightening up and bending motions.

Rotor position is affected by changing conditions; to ensure accurate installation of the PCP rotor and maintain its position throughout operation it is necessary to monitor its position rather than rely on calculations. A new technology has been introduced that will provide real time information on the position and movement of the rotor in the stator and measure the torsion effects in the rod string. These measurements will improve the operational life of the PCP by ensuring the system is run under optimal conditions, and provide the information to be able to adjust the system in real time minimising unnecessary and undesirable stresses.

Introduction

The Progressive Cavity Pump (PCP) can be applied as a relatively simple artificial lift system. The PCP consists of three main components: a helical steel rotor, an elastomer bonded inside a steel tube and a drive rod string to transmit rotational power to the rotor from a drive unit located at surface.

The rotation of the rotor inside the fixed stator causes a series of sealed cavities to move axially along the pump. Depending on the direction of rotation, fluid within theses cavities is progressed from the lower pressure intake to the higher pressure discharge thereby producing fluid to surface.

In most applications the stator is run into the well on the bottom of the production tubing. The rotor is then installed on the bottom of a rod string used to drive the rotor. A tally of the rod string relative to the tubing string is conducted to ensure the rotor is positioned correctly inside the stator. A tag bar is located under the stator to ensure the rotor is not lost downhole should the rod string break. The tag bar is also used in the space out procedure as a reference to position the rotor inside the stator during installation.

The rod string is turned by a surface drive unit which in turn drives the rotor downhole. The rod string is subject to various forces during operation which effect the position of the rotor inside the stator and also subject the metal rods to fatigue. Inadequate design or installation of the rod string will often lead to operational problems and premature failure resulting in costly workover.

This paper discusses the dynamic system which interacts between the well producing fluids, pump and rod string and details new methods and technology that can be implemented to increase the knowledge of what is happening to the downhole pump.

Factors Effecting Rotor Position

The rotor must be carefully positioned inside the stator to ensure maximum efficiency of the pump is achieved. The rotor position is set during installation by a space out procedure. The space out of the rod string and rotor depends on the loading on the rod string suspended inside the tubing from surface and the correct positioning of the polished rod and clamp during the space out. Typically the rotor is run through the pump barrel until the rotor tags the tag bar a short distance below the pump stator. Weight is lost from the surface hoist as the rotor comes to rest on the tag bar. Using a weight indicator, the slack is then taken up by picking up the rod string. The rod string is lifted an additional amount based on a set calculation and to counter rod stretch due to the effects mentioned above. It should be noted that this calculation is based on expected fluid properties and well conditions and any error in these will reflect on the rotor position.

The space out procedure relies on a number of variables including accurate indication of when the rotor lifts from the tag bar, an accurate calculation for operational rod stretch and correct positioning of the rod support clamp when landing.

There are three main sources of rod string loading which contribute to the stretch in the rod string.

Axial Loading

Axial loading is caused by the weight of the rod sting and rotor suspended from surface and the hydrostatic plus wellhead pressure (back pressure) acting on the pump stages. See Figure 1. In addition to the loads causing the rods to stretch, thermal expansion due to temperature may induce compressive loading of the rod string if the stator is secured using a torque anchor. In more viscous fluids the upwards flow of the producing fluid will act against the downward axial load as it produces up lift forces on the rods and couplings.

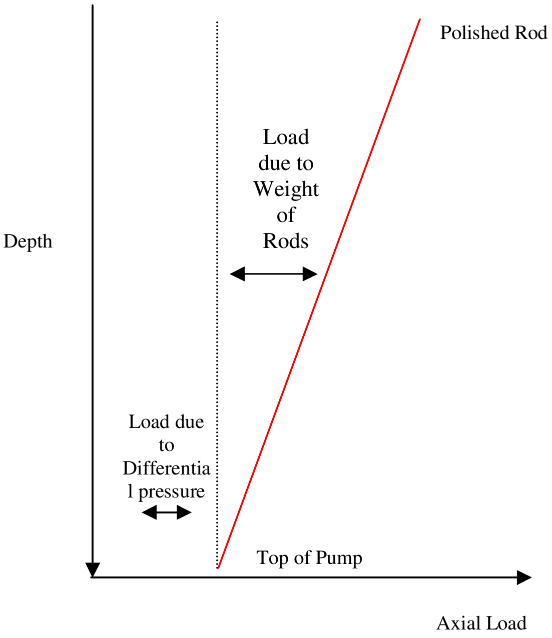


Figure 1 – Rod String Axial Loading

Torsional Loading

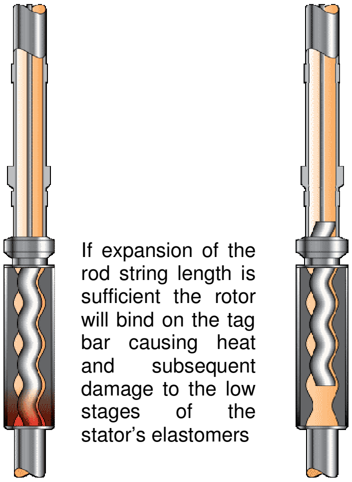
Torsional loading of the rod string is caused by frictional loading from the interference fit of the rotor inside the stator as the rotor is turned, hydraulic loading due to the differential pressure developed by the pump stages and frictional loading from the rod/tubing contact. Additional torsional loading of the rod string can occur in heavy fluids due to the fluid shear between the rod string and the tubing.

Bending Load

As the torsional loading of the rod string increases the rod string will twist or wind up to a degree dictated by the torque applied and torsional loading encountered. This will induce an amount of bending to the rod string depending on the axial loading developed by the pump, rod string weight and number of rod centralisers run in the completion. Deviated wells will magnify the bending of the rods.

Axial loading has the greatest effect on the position of the rotor within the stator, varying for example by 3000 lbs/ft during operation, but a combination of torsional loading, temperature expansion and bending may also contribute to movement of the rotor during operation.

It can be seen that optimal position of the rotor within the stator is dependent on many variables which will vary when the pump is brought on line and operational or well conditions change. (See Figure 2)



If expansion of the rod string length is sufficient the rotor will bind on the tag bar causing heat and subsequent damage to the low stages of the stator's elastomers

If the rod string length shortens enough that the rotor protrudes over the top of the stator the efficiency of the pump will decrease.

Figure 2 – Effects of Axial Load on rotor Position

The rotor will move downwards relative to the stator as axial loads increase and the rod string length expands.

Axial load will increase where there is an:

- Increase in hydrostatic pressure caused by wellhead / flow line pressure.
- Increase in hydrostatic pressure due to an increase in fluid density, for example increasing water cut.
- Increase in pump differential pressure due to an increase in pump speed.
- Increase in pump differential pressure due to well performance changes.
- Increase in rod length due to thermal expansion, especially when the stator and tubing string is supported below using a torque anchor.

The rotor will move upwards relative to the stator as axial loads decrease.

Axial load will decrease where there is an:

- Decrease in hydrostatic pressure due to a decrease in fluid density, for example pumping off kill fluid or increase in GOR.
- Decrease in pump differential pressure due to fluid properties changing e.g. reduced viscosity.
- Flow rate inducing lift on the rod string couplings.

In addition, the overall rod string length may shorten if excessive twist is introduced into the rod string due to torsional loading causing buckling of the string. (Figure 3). The bending can be minimised by the use of centralisers on the rod string.

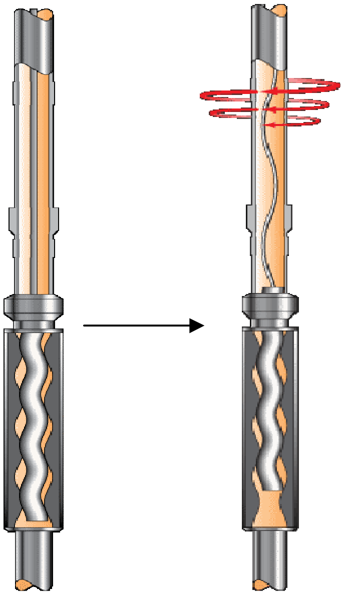


Figure 3 – Effect of rod wind up on rotor position

Operational Consequences

Although axial load can be calculated, there are a number of variables that are constantly changing during operation. The actual position of the rotor during operation is unknown yet it plays a significant part in optimizing pump performance and runlife.

The position of the rotor during operation is also dependent on the initial position set during installation. In extreme cases the pump is initially started with the rotor not inserted or only partially inserted into the stator (figure 4 & 5). In other cases the rotor is positioned too low to account for axial loading and immediately binds against the tag bar when axial loads are introduced. A solution to this has been to move the tag bar further below the stator but apart from preventing wear this still means the rotor is protruding too far out the bottom of the stator to give optimal performance.

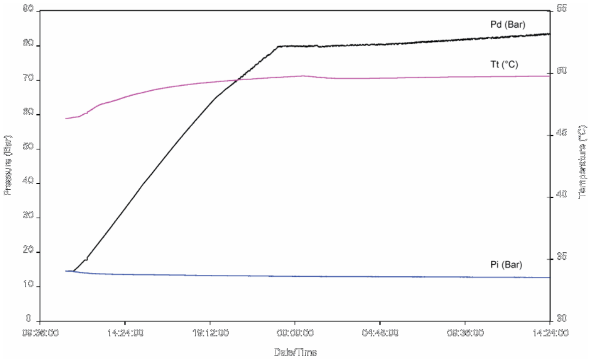


Figure 4 – PCP start up with rotor inside stator

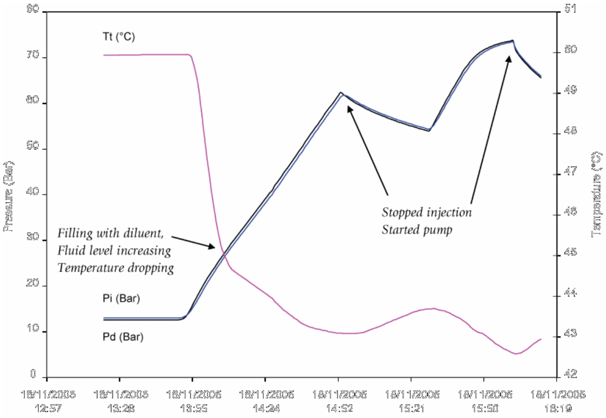


Figure 5 - PCP start up with rotor above stator

Factors Effecting Rod String Torsion

Torque is applied to the rod string at surface by the surface drive unit. The system is subject to a varying distributed torsional load over the length of the rod string and pump (figure 6) due to the friction from the turning rod string and rotor plus hydraulic forces acting on the pump as described in the previous chapter. As we progress down the rod string the torsional load increases reducing the effective torque applied to the pump rotor (Figure 7). The torsional load does not vary linearly but changes with factors such as pump speed, fluid properties, rod / tubing contact, back pressure etc. The resulting forces create dynamic twisting in the rod string as the torsional load constantly changes. The total twist, or wind up of the rod string is apparent when the pump is switched off and the forces built up act to put the drive unit into back spin. If left unchecked this can resulting in significant damage to the drive and therefore a braking system is applied to hold the rods from back spinning at surface.

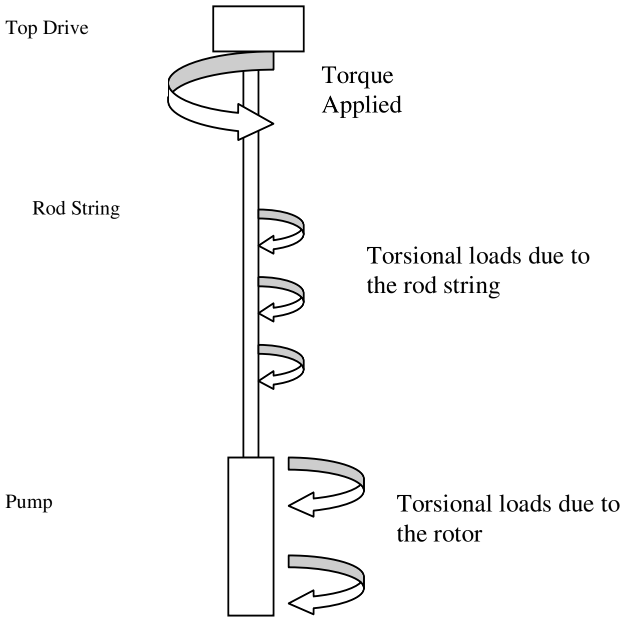


Figure 6 – Torsional Loading of the Rod String

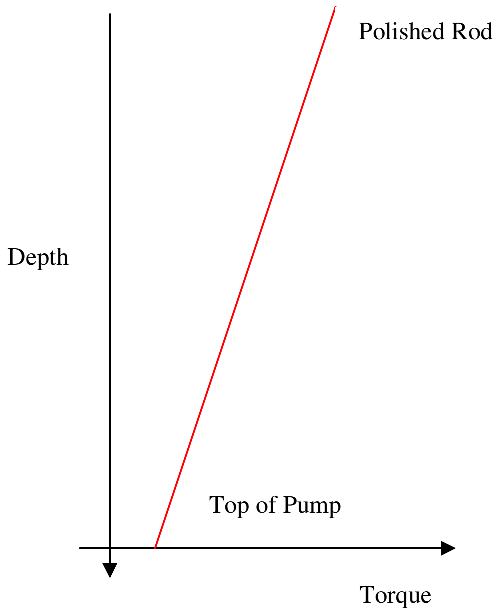


Figure 7 – Torque Diagram (illustrative)

The amount of wind up in the rod string is contributed to by a number of factors

- The torque applied by the drive
- The torsional rigidity of the rod material
- The length of the rod string
- The torsional loading across the system which varies with operational changes

The degree of twist in a uniform circular shaft can be calculated from the Torsion Equation

$$\frac{T}{J} = \frac{G\theta}{L} = \frac{\tau}{r}$$

$$\theta = \frac{\tau L}{rG} = \frac{TL}{rJ}$$

T = External Torque applied
J = Polar Moment of inertia
G = Shear Modulus of material under bending
L = Length of shaft under torsion
θ = Angle of twist (radians)
τ = Shear stress level in the shaft
r = Shaft radius

However a string of sucker rods is usually utlised to drive the rotor. A sucker rod is not of uniform roundness due to the profile of the couplings. Also the torsional loading is not uniformly applied to the rod string over its length due to different contact patches between rod and tubing and varying viscosity with temperature and depth.

Evidence of Rod Twist during start up.

For example when the pump is initially started the torque applied at surface acts to wind up the rod string until sufficient torque is transferred to the rotor to break it free of the frictional forces inside the stator due to the interference fit.

An example start up is included in figure 8.

The top drive is started at 12:57 as indicated by the torque plot in green. The surface drive is started at a speed of 50 rpm. Evidence from the downhole pressure gauge shows that movement of the rotor does not occur until approximately 2 minutes after the drive is started. (Discharge pressure does not show any pressure increase until the rotor starts to move). This equates to approximately 100 turns induced in the rod before the rotor starts to turn. This gives only an approximation of the number of turns in the rod string due to sampling rate of the devices and ramp up speed of the drive. Further twisting / untwisting can be expected as the pump speed is adjusted further and loading increases/decreases.

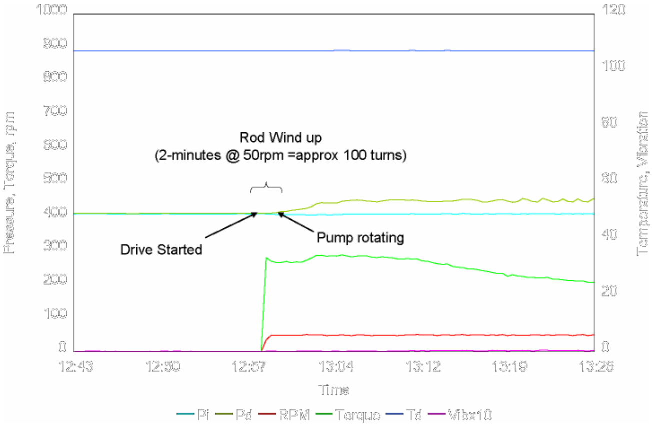


Figure 8 - Rod Twist Evidence during PCP start up

This phenomenon can be expected to continue as fluid is produced up the tubing string; back pressure increases on the pump creating additional loading further acting on the forces creating rod twist. Changes in fluid properties such as increasing water cut, gas slugging, or changes in fluid viscosity also contribute to changing torsional loading on the rods further complicating the calculations required to assess the amount of twist in the rods.

The consequence of this dynamic torsional loading is that the rotor may not be turning at the same speed as the surface drive unit, and over a period of time be winding and unwinding the rod string causing undue stress and fatigue leading to early failure of the drive rods.

Increased torsional load will give increased wind up in the rod string moving the rotor upwards relative to the stator. However, some forces influencing increased torsional loads, eg speed increase, may act to increase axial load pushing the rotor back downwards. Decreased torsional load will decrease the wind up in the rod string moving the rotor downwards relative to the stator.

The amount of twist encountered is therefore an unknown quantity; however it is an important factor in considering the life cycle of the producing system.

Conclusions

PCP runlife is gauged by the number of cycles the pump undergoes before failure. Runlife in terms of time is not an ideal method of measuring runlife performance for a PCP as life of the pump is directly relational to the speed it is turning. For example, A PCP running at 300rpm for 1 year has had a much harder service than one running at 100rpm in the same conditions for the same period.

It can be concluded from the arguments in this paper that in addition to its normal rotational movement, the rotor is in a constant state of axial movement up and down the stator due to the changes in well and operating conditions. This is exaggerated by wind up of the rod string acting to shorten and lengthen the overall depth of the rotor. It can also be concluded that the downhole pump is not turning at a constant speed in line with the surface drive due to the changing torsional loading on the rod string and rotor.

The rotor is therefore moving both rotationally at an inconsistent rpm, and vertically depending on load. The movement of the rotor in the stator produces frictional wear. The more movement the rotor undergoes relative to the stator, the more wear will be apparent. The speed of wear is exaggerated by the properties of the fluid being produced.

It is proposed that run life can be effectively measured using a combination of two axis of rotor movement.

1. Total Downhole Rotor Cycles. (Rotational movement)
2. Total Vertical displacement. (Axial movement)

Vertical displacement can also be expressed relative to time (eg. cm / minute) to give an instantaneous indication of rotor movement with given operating conditions.

The ability to precisely monitor the position of the pump rotor during the installation process will reduce installation errors and help to place the rotor in the correct position ready for start up. Further to this, the ability to then monitor the actual positional changes of the rotor during production enables the option to adjust the rotor position manually or in real time to ensure the optimal position is maintained with changing conditions to enhance runlife and production.

The measurement of torsion (or rod string twist) will enable the rod string performance to be assessed. A table detailing type of rod, depth, number of twists encountered is shown in Figure 9. The table is intended to be used as a learning process whereby a performance chart can be built as rod string failures are encountered. This will enable set point of alarm and/or control settings to warn of or act upon over torsion in the rods. A measurement of torsion combined with surface torque will enable a more thorough assessment of rod performance to be made and enable the ability to vary surface drive speed to minimise stresses on the rod string.

The relationship between rotor position and load under dynamic conditions is difficult to calculate due to the high number of factors and unknown variables acting on the system. Combining information on measurements from rod string torsion, rotor position downhole rotor speed and surface drive speed is proposed to help us better understand what conditions the rotor and elastomers are undergoing downhole (figure 10).

Additional measurements such as axial movement can be derived from these parameters to assist with performance tracking of equipment behavior.

The Way Ahead

PCP monitoring technology has progressed from simple fluid shot measurements and surface parameters to downhole pressure, temperature and vibration sensors combined with surface torque and variable speed drive speed measurements. Although these technologies are now common place in more prolific PCP lifted wells they are limited in how they monitor the mechanical performance of the downhole pump to directly address mechanical failure. PC based design software is enhancing the design process by including comprehensive rod string loading calculations to ensure optimal equipment selection.

New technology is now available which will directly measure rotor position, rod string torsion and downhole rotor speed. The simple application of a rotor position indication during installation will help PCP runlife significantly by ensuring the exact location of the rotor is known before start up. Further to this the technologies ability to monitor the rotor position in real time enables the rotor position to be dynamically adjusted as movement due to loading occurs during pump operation.

Application of these parameters with downhole pressure gauge information, and surface drive and well test information will enable a better understanding of the PCP system and further extend PCP life cycles.

Field Trial Torsion Database

Rod Size	*Manufacturer Average Rod Break Point*	*Material Type*	*Length*	*Total Cycles This run*	*Total Cycles all runs*	*Torsion/M This Run*	*Recommended Alarm Level*	*Recommended Trip level*
1.0	*X co. 350/1000m*	*Sld*	*1500M*	*xxxx*	*xxxx*	*240/1000m*	*320/1000m*	*340/100m*
1.5	*X co. 290/1000m*	*Hlw*	*2000M*	*xxxx*	*xxxx*	*270/1000m*	*260/1000m*	*280/100m*
1.0	*Y co. 400/1000m*	*Sld*	*1500M*	*xxxx*	*xxxx*	*300/1000m*	*370/1000m*	*390/100m*
1.0	*C co 650/1000m*	*Sld*	*1500M*	*xxxx*	*xxxx*	*450/1000m*	*620/1000m*	*640/100m*

Figure 9 – Torsion Data Base Example

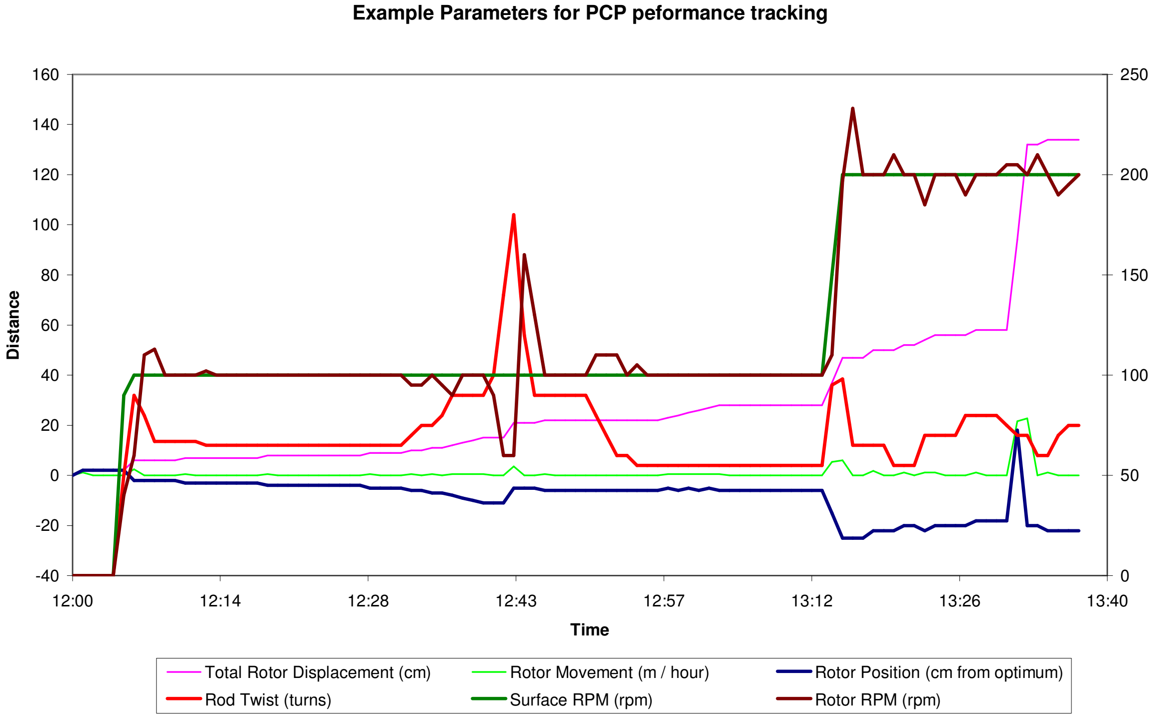


Figure 10 - Parameters for Improved Monitoring of PCP Operation

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