HOW CAN AN OPERATOR/PUMPER OPTIMIZE A ROD PUMPED WELL

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ABSTRACT

An Operator/Pumper is typically expected to produce their assigned wells in a manner that results in a maximum allowable production rate at a minimum of cost. However, they must do so with the wellbore conditions, equipment, and operating environment they are assigned. This paper will present some tools and methods that the Operator/Pumper can utilize to help optimize a rod pump well.

INTRODUCTION

This paper will focus on the role of the Operator/Pumper in optimizing rod pumped well operations by using the tools and methods that are most commonly available.

In this context, "optimization" can be generally described as making the best use of the currently installed pumping equipment in order to maximize revenue while minimizing cost. The goal is maximum profit which can be generally defined as revenue less expense or as income minus cost. The optimization process usually includes surveillance and analysis in order to identify opportunities for improvement and then revising the pumping system accordingly. One particular area of optimization deals with what is often called "Problem Wells" or well with an abnormally high failure frequency. There is no consistent industry definition of "Problem Wells" but in general, wells that have more than two failures in a 12 month period should be considered as candidate for optimization.

This paper will not address failure diagnostics, improving well productivity such as acidizing and fracturing or change of artificial lift type.

WELL PERFORMANCE

Every well performs differently even those in the same field so it is important to monitor and track a well's performance. Well data can be plotted to estimate a well's projected performance based upon the bottomhole pressure such as shown in Figure 1. The important thing to understand is that a well can usually achieve its maximum production rate at the lowest achievable bottomhole pressure that is typically determined by hydrostatic pressure in the casing/tubing annulus.

Hydrostatic pressure is defined by adding the surface pressure and the hydrostatic pressure of the gas, oil, and water in the wellbore. In a rod pumped well, the surface pressure is measured on the casing side making that pressure and the fluid level important in determining the producing bottomhole pressure which is often times described as the pump intake pressure (PIP).

ANALYSIS TOOLS

There are several tools that should be considered when attempting to evaluate a well's performance to determine if it is being optimized.

Production Trends - In order to optimize a rod pumping system it is necessary the Operator/Pumper know the volumes of oil, water & gas that a well is currently producing and how those volumes have trended over time. Have the rates increased, decreased, or remained constant. Since these values are crucial in making optimization decisions, it is important that they are accurate, reliable, and monthly if possible. Therefore, the Operator/Pumper must fully understand the source of the data and be comfortable that it is worthy of use in the decision making process.

Cost Trends – usually, the most useful cost trends are Power (electrical or fuel) & Operating Expense. While an Operator/Pumper normally does not have access to the costs, they should be aware of those factors that account for the operating costs. Electrical/fuel costs are determined by horsepower requirements which are adversely affected by increased loading from paraffin buildup, out of balance units, belt slippage, over pumping, excessive tubing backpressure, excessive stuffing box friction, and/or leaking casing check valves.

POC/Dynamometer Trends – monitoring these trends can alert the Operator/Pumper to any changes that may affect optimum well operation. Typical trends include run time, polished rod horsepower, dynamometer card shapes (surface & downhole), fluid loads, pump intake pressures, torque numbers, indications of gas interference or incomplete pump fillage, indications of loose TAC, sticking pumps, tubing flowing off, etc.

Fluid Level Trends – acoustic fluid levels are the most common method used today. A periodic fluid level is recommended to help monitor downhole conditions, but is a necessity if a POC is not available. This especially true with wells associated with waterflood and/or CO2 injection.

Well Failure Trends – well failures lead to lost revenue and increased operating cost to repair the failure; therefore, an optimization program must include a planned approach to minimize well failures. No one knows the wells better than the Operator/Pumper so communication of how the well is operated and any known issues with the well is a top priority. This information can be critical to identifying the "root cause" of the failure.

POTENTIAL AREAS OF OPTIMIZATION

Run Time – if the well is not equipped with a POC, it is important to control the run time so that the well is achieving maximum production while at the same time minimizing over-pumping to prevent damage to the equipment. It is very difficult to achieve the proper balance of run time with idle time with percentage timers (the most frequently used timer) since they operate on fifteen (15) minute cycles. Pump-off controllers (POC) were designed to achieve the proper balance since the well will run as long as needed to "pump the well-off" and the idle time can be adjusted for each well.

Ideally, the fluid level is pumped down to the same level as the pump inlet, but realistically this is seldom achieved. As the fluid level drops, the pump fillage starts decreasing and there is a point at which the well is over-pumped resulting in rod buckling. This results in premature failures and increased electrical costs due to over pumping the well. The fluid level and related pump fillage differs from well to well so the best solution is to monitor the fluid level and dynamometer cards to achieve the optimum setting. Gas interference makes this more difficult, but a POC helps to achieve the optimum setting.

Low runtimes and/or short cycle times are the result when a well is over-pumped. This often occurs when the capacity of the system becomes much larger than the actual production rate. The easiest method for an operator/pumper to impact this is to slow the unit down by reducing the SPM, if possible. This will extend the life of the equipment and slightly reduce electrical costs. A good rule of thumb is if a well is running about 65% or less and the SPM is greater than 5, then evaluate slowing the unit down.

High runtimes are often the result of an under-pumped well. An under-pumped well will typically have a high fluid level which can negatively impact production, create more gas interference in the pump, and hinder chemical treatments. This may be the result of an undersized or worn pump or possibly an undersized system. Fluid levels and dynamometer analysis help to determine the exact cause. However, whatever the cause should be immediately communicated to the appropriate personnel so that the proper actions can be determined.

Idle or down time – this is the amount of time that the well should be down to minimize well cycling by maximizing the amount of fluid that is accumulated in the wellbore during downtime. When a rod pump well shuts down, fluid begins to fill up the tubing-casing annulus and will continue to build until enough pressure is built that inhibits or stops fluid inflow. Ideally, the fluid is allowed to build until just before it quits building as demonstrated in Figure 2.

Gas Interference – makes it much more difficult to optimize a well. However, two things can assist a pumper in minimizing gas related problems. The first tool is a back pressure valve to hold additional pressure on the well's tubing. Enough tubing pressure can keep gas in solution preventing it from initiating "slug flow" which results in fluid flowing out of the tubing. This results in unlubricated stuffing boxes which may ultimately lead to damaged packing and a leak. This results in downtime, loss revenue, and increased costs. The best answer is whatever pressure is needed to keep the gas in solution. However, be careful to not add pressure when not needed as it requires additional horsepower to lift the fluid increasing power costs.

Severe gas interference can result in a low downhole pump efficiency resulting in longer run times and/or high fluid levels. Hopefully, the pumps that have been run in the wells have been built to optimize the pump's compression ratio by minimizing the "unswept" volume of the pump. The operator/pumper can ensure that the compression ratio is maximized by properly spacing the pump to ensure that the plunger/traveling valve gets as close to the standing valve as possible as shown in Figure 3, Examples 1 and 2. Each well should be re-spaced as soon as it has stabilized after a workover. However, this is not easily accomplished with fiberglass rods since they cannot be put into compression. One method to assist is to carry a higher fluid level or PIP to assist with the compression ratio. Example problems are shown in Figure3, Example 3.

Belt Slippage – any belt slippage whether it is from loose belts and/or worn sheaves should be corrected as it requires more power and thus raises costs. Ensure that belts are properly installed by ensuring that the motor and unit sheaves are aligned, belts are taunt, and not rolled onto the sheave. Periodically have someone inspect the sheaves to see if they are worn and need to be replaced.

Pump Condition – The age old question is "when is it best to change out a worn pump" and the answer is "That depends on many factors". It may be possible to compensate for a worn pump by increasing the run time, increasing the SPM or SL but ultimately it is an economic decision that should balance the cost of repair against the amount of revenue that is being lost.

Pumping Units – a properly balanced unit with good lubrication and care can last many years. However, an out of balance unit results in more gearbox torque that can be damaging to the unit while also raising electrical costs. A unit that starts leaking gearbox oil and/or grease or making unusual noises should be reported immediately to ensure that proper repairs are made. A "cratered" unit results in downtime and major repair costs.

CONCLUSION

There are many things that an Operator/Pumper has to "live with", but fortunately there are several things that they can do to optimize the wells and equipment that they are assigned. These options can result in increased production and/or reduced operating costs which result in maximizing the overall profit.

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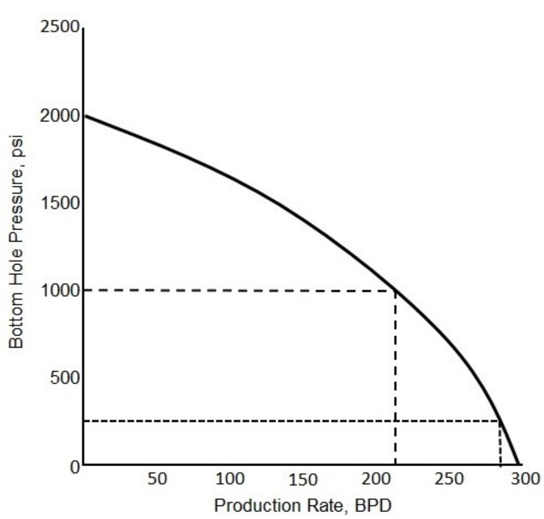


Figure 1

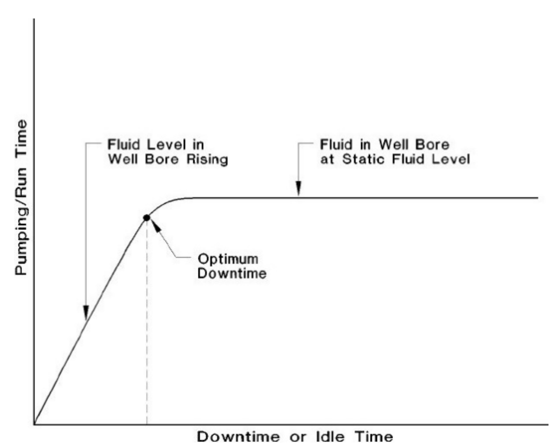
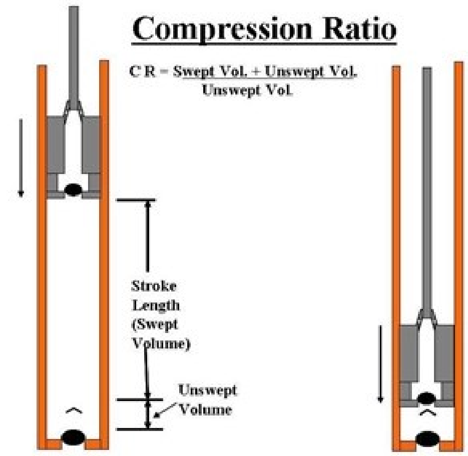


Figure 2



Example 1:	**Example 2:**	**Example 3:**
SL = 144"	SL = 144"	SL = 144"
Unswept Vol. = 1"	Unswept Vol. = 6"	Unswept Vol. = 6"
Depth = 8000'	Depth = 8000'	Depth = 8000'
SG fluid = 0.44	SG fluid = 0.44	SG fluid = 0.44
Fluid level = 8000'	Fluid level = 8000'	Fluid level = 7750'
PIP = 100 psi	PIP = 100 psi	PIP = 210 psi
CR = 145 to 1	CR = 25 to 1	CR = 25 to 1
Above TV = **3520 psi**	TV = **3520 psi**	TV = **3520 psi**
Pump will generate **14500 psi**	Pump will generate **2500 psi**	Pump will generate **5250 psi**
Gas interference minimized	*Gas interference issues*	*Gas interference minimized*

Figure 3