AN ANALYSIS OF COMMON SUCKER ROD PUMPING FAILURES AND PRACTICAL SOLUTIONS TO PREVENT REOCCURRENCE

Mark W. Mahoney
Harbison-Fischer

ABSTRACT AND SCOPE

This paper will focus on the primarily causes of damage to sucker rod pumps and other parts of the sucker rod pumping system. The focus is on the most common problems that I see reoccur frequently. This information is based on the findings from studies of analysis of broken and/or worn pump parts over a 6-year period, results from field failure analysis teams and field reports.

INTRODUCTION

The root cause of typical pump failures can be broken down into 4 groups.

1. Misdiagnosis of well problems
2. Well conditions
3. Operational parameters
4. Misapplication

MISDIAGNOSIS OF WELL PROBLEMS

This is often the most costly problem because the wells are often pulled several times to correct the problem but the wrong pump or other equipment is used and the problem is not corrected and sometimes the situation is even made worse. One of the most frequent causes is that an assumption is made and pushed forward, and then everyone involved in the corrective action is working in the wrong direction. The corrective action team should be given the known facts or best data rather than an assumed diagnosis. For example; a well is not making the production it should with the current pump and the well produces gas so often there is a jump to the conclusion that the well is "gas locked" at times. The directive is given to get a pump that will not gas lock. The well is pulled, the pump installed and nothing changes. A wellhead pump test is performed and dynamometer cards are cut and it turns out to be gas interference instead of gas lock. The well is pulled again and an efficient bottom hole gas separator is installed to alleviate the problem.

GAS PROBLEMS

Gas lock is often used to describe any gas problem so I will cover the most common gas problems with a description of each and methods to fix the problem.

- Gas lock

  True gas lock is fairly rare and in my experience usually occurs close to the well pumping off so the two are blurred together. The dynamometer cards will look very similar, the surface pump check will look the same and a standing valve stuck open often looks the same.

  True gas lock exists when the hydrostatic pressure on the top of the traveling valve ball is greater than the pressure exerted on the pump chamber side of the traveling valve at the bottom of the down stroke. On the upstroke the gas expands in the pump chamber but the pressure in the chamber remains above the pump intake pressure and the standing valve does not open. So with true gas lock the valves stay closed and the same column of fluid is raised and lowered with each cycle and no fluid is being pumped. The dynamometer card will show a flat "worm card" at the peak polished rod load area on the card because the traveling valve is not opening to release the fluid load and drop to the minimum polished rod load. If you are watching a gauge on the bleeder valve with the flow line closed, the pressure will rise and then drop back but not continuously build pressure.

  Gas lock and stuck valves are often confused. Adding double valve cages (both the traveling valve and standing valve) have returned many wells back to pumping that had been diagnosed with "gas lock".

- Gas interference

There are two different types of gas interference. One occurs most often on new wells that flowed for a period of time and then dropped in production and a sucker rod pump was installed. What happens quite often on this type of well is the pump will contribute to the flowing and the term often used is “frumping” (flowing and pumping.) Sometimes this will balance out and the desired production level is reached but more often the pump starts a gas lift type situation and then the well unloads, blowing the tubing dry and then the gas coming through the pump keeps the valves from functioning properly and the well has to load back up with fluid before the pump starts to function again. During the period when the pump is not functioning or is functioning but has not yet filled the tubing, the gauger will check the well and find that he cannot build pressure with the flow-line closed and report the well is down. Most of the time the well will be pulled and the pump will be checked and found to be in perfect operating condition. One of the best ways to combat this problem is to use a backpressure regulator to hold pressure on the tubing. Over the years I have found the best method is to simply set the pressure by listening to the backpressure regulator and the flow line check valve. First thing is to find out your polished rod size and down-hole pump size. If the pump plunger OD is larger than the polished rod size then the fluid will pumped into the flow line on the upstroke. If the polished rod is larger then the displacement of fluid will occur on the down stroke. With you ear fairly close to the backpressure regulator you can hear the fluid and gas mixture as it rattles the valves in the regulator and the flow line check valve. Start adding pressure to the valve until you hear the rattling stop during the part of the cycle when the fluid would not be normally be pumped into the flow line. If the pump plunger OD is larger than the polished rod then you will want to stop the valve rattling on the downstroke and you only hear the gas/fluid chatter on the upstroke. The more common type of gas interference takes place when gas is pulled into the pump chamber with the liquid and then often expands due the pressure drop in the pump chamber. This causes less liquid to enter the pump resulting in poor pump efficiency. This type of gas interference also caused gas pound and the resulting sucker rod compression above the pump. The best way to combat this type of gas interference is to use a good down-hole gas separator system. There are many papers available on separator design so I will not cover that in this paper.

PUMPING SPEED

There are a number of problems with the terminology used in sucker rod pumping that lead to misconceptions right from the start. One of these terms is the use of “Strokes Per Minute” often abbreviated to SPM. There is actually a downstroke and an upstroke in each pump cycle but the full cycle is always called a “stroke”. Cycles Per Minute may be more appropriate but we will stick with SPM because it is the recognized term in use in the oil field today, just remember that each “stroke “ in “strokes per minute” is actually the upstroke and downstroke it takes to complete a cycle.

The second most misunderstood concept is the speed of the pumping unit. Once again the using SPM can be misleading. SPM does give you the cycles per minute but it does not tell you how fast the pumping unit, polished rod, sucker rods and pump is moving. To get the average speed of the pumping system you have to calculate the linear speed.

Linear speed is important because the pumping unit can actually travel faster on the down stroke than the sucker rods can free fall through the fluid. This can cause slack between the carrier bar and polished rod clamp resulting in damage when they slam back together. This is also one of the causes of premature sucker rod failure and fatigue breaks in pumps due to deflection. Linear speed is not just the amount of time it takes to complete a cycle but the number of inches covered in the cycle. This means that we have to also consider the stroke length as well as the SPM. The typical formula used is to simply multiply the two, SPM x SL to get the average speed in linear inches per minute. A good rule of thumb is to not exceed 1400 linear inches to avoid rod compression.

For example if our SPM is 10 and our SL is 144” then: 10 x 144 = 1440

You may have noticed that I talked about this as an “average linear speed” and this exactly what it is. The stroke actually starts out at top then accelerates positively to the middle of the stroke and then goes into negative acceleration at the end of the stroke until it stops and then reverses. The speed of the rods at any point in the downward or upward cycle will depend on the pumping unit geometry. The long story short is that somewhere in the middle of the up or downstroke, the rods are traveling at a velocity much greater than the average linear speed.

The linear speed of 1400 or less rule of thumb is a good guideline but at times you may need to push this to a higher rate especially with longer stroke lengths. When that is necessary I have found that the formulas from Lufkin’s pumping unit catalog to work well. See **Fig. 1.**

BROKEN PARTS DUE TO DEFLECTION

The majority of parts examined in some years are fatigue breaks due to deflection. Besides the excessive speed problem described above, the most common causes of the deflection are.

- Fluid pound
- Gas pound
- Well bore deviations (planned and unplanned)
- Tubing movement and tubing anchors that have slipped putting the tubing in compression.

FLUID POUND

Fluid pound is one of the most common and most destructive operational problems causing deflection of the sucker rods, pull rods and pull tubes. This will cause fatigue type breaks and also cause friction wear on parts that are driven into the tubing wall and send impulse waves through the parts causing threaded parts to unscrew. Various methods are often used to control fluid pound; timers, vibration controls, pump off controllers and well controllers (smart controllers).

Timers often serve very well if manpower resources are good. To get a good timer setting someone has to stay with the well and monitor its performance for hours of time for a number of days. Well inflow data and pump performance data can be used as a starting point but to really fine tune the timer settings hands-on monitoring is usually necessary. There is still the problem of changing reservoir conditions and this requires occasional re-setting of the timers to keep from pounding fluid or under producing.

Vibration controls are good tools to detect mechanical problems with the pumping unit and shut down the unit but should not be used for pump-off control. The problem is a lot of damage can occur downhole before the vibration is transferred to the unit.

Pump-off controllers and well managing controllers both usually work off a load cell (some use other methods like hall effect sensors) and allow the setting of a threshold on the downhole card. This is set at some point at the beginning of the downstroke card. If the traveling valve does not open at the beginning of the downstroke the controller will read this as fluid pound. Most units allow the threshold to be moved and also allow for a repeated amount of strokes before the unit is shut down and this is where problems occur. If the threshold is set too far into the downstroke the forces of the free-fall of the plunger will increase and cause damage. If the unit is set to allow numerous strokes before shut down, then an accumulation of say 7 strokes per shut down happens 10 times a day, then you have 490 fluid pounds a week. Over time this can cause cyclic fatigue, friction damage and loosen connections.

GAS POUND

Another source of deflection is gas pound Gas pound is one of the problems caused by gas interference. Gas pound is similar to fluid pound but instead of a free-fall and then a collision that occurs with fluid pound, gas in the fluid starts compressing slowing the downward acceleration and has a cushioning effect. This helps limit the force and impact but still causes the sucker rods, valve rods and pump parts to deflect. One of the most common symptoms is that the pump is not delivering the production it should and the conclusion is the pump needs to be replaced. This happens often and is a costly problem because it so often misunderstood. When a pump is not pumping efficiently it is best to have a dynamometer test and also conduct a pressure test by closing the flow line for a few strokes to see if the pump builds pressure. If the fluid is mostly gas it will build pressure slowly with each stroke and a bleeder valve sample will also lose part of its volume as gas breaks out and evaporates. Quite often the percent of gas breakout in a sample will match the percent of gas pound on the dyno card and be close to the percent of efficiency the pump has lost. When this is the case there are really only a few choices and those are.

- To build a good down-hole gas separator to eliminate as much the gas from the pump intake as possible, use a larger pump (live with inefficiency) and use sinker bars to counter the rod compression.
- Use a pump that allow the traveling valve to equalize at the top of the stroke and eliminate the rod compression (Variable Slippage Pump®.)

WELL BORE DEVIATIONS

Horizontal drilling is very popular and if drilled with a medium or large radius can be successfully sucker rod pumped with a minimum amount of problems. Most horizontal wells that have been drilled in the last ten years have a well bore survey and this can be used to pick the best area to land a pump. Survey data can also be used with computer programs such as Lufkin's S Rod to determine the ideal amount and location of sucker rod guides. Doglegs can also be present in vertical wells and cause minor frictional wear to rapid metal loss from friction and pump parts breaking due to deflection and fatigue.

One of the things that often occurs is a valve rod will suffer a fatigue break at the last engaged thread of the top plunger adaptor. The pump shop installs a collet type valve rod adaptor that supports the valve rod and the pump is returned to the well and a few weeks later the pump is again pulled and the break has moved to another area such as the plunger pin below the top plunger adaptor. When something of this nature occurs I can almost guarantee that it will continue to be a problem due to a dogleg. The break may be moved to another spot or the pump design beefed up so it takes longer to fail but it will continue to be a problem. If a well bore survey is available it should be used to find a new position for the seating nipple or if a survey is not available, then move the pump up or down one joint of tubing and try pumping from that location. In one unusual case we were sent a 3-1/4" diameter plunger with all of the sprayed metal worn off of the plunger outside diameter (OD). The barrel was oval shaped on the inside diameter (ID) and one side of the barrel ID was almost worn through. This was due to severe deflection of the pump. The reason the plunger was worn out all the way around its circumference was due to the fact they had a rod rotator on the well.

UNANCHORED TUBING

In wells that are over 2,000 feet deep tubing movement on unanchored tubing can cause enough deflection to sometimes cause damage to a pump. One case that is a good example; a group of wells were operating at 2,900' to 3,200' and top hold down pumps were used. The hold down body was being broken at the barrel bushing and frictional wear was being found on the bottom OD of the pump barrel. The sucker rod couplings, valve rod and guide showed frictional wear consistent with deviation type damage. The tubing movement although small at this depth was being deflected with some well bore deviation and causing the pump damage. Pump anchors were installed and the failures declined to almost zero.

SLIPPED TUBING ANCHOR

This does not happen too often but can cause deflection problems all up and down the tubing string. This usually occurs when the anchor slips down hole and loses the tension that was initially applied. The tubing anchor slides upward and then stops leaving the tubing in compression. This can often be picked up on a dyno card or when the pump is pulled and frictional damage is observed.

CORROSION PROBLEMS

Corrosion is a complicated subject and often misunderstood. I do not consider myself an expert in this field but do wish share some of the most common problems and ways to help identify and correct them.

There are many different corrosion problems that exist down hole and can affect the sucker rod pump.

Acidic corrosion is one of the most common and the acid is created from bubbling gas through produced waters. H_2S and CO_2 are the most common and the NACE specification MRO176 provides the following guidelines.

- Mild metal loss will occur when water cuts are less than 25% and H_2S is less than 10 ppm and CO_2 is less than 250 ppm.
- Moderate metal loss will occur when water cuts are between 25%-75% and H_2S is between 10 ppm and 100 ppm and/or CO_2 is between 250 ppm and 1,500 ppm (high concentrations of CO_2 at low pressure are not corrosive, i.e, in shallow wells less than 1,000 ft.)
- Severe metal loss will occur when water cuts are over 75% and H_2S is greater than 100 ppm and C02 is 1,500 ppm (high concentrations of CO_2 at low pressure are not corrosive, i.e, in shallow wells less than 1,000 ft.)

The thing to note here is that as water cut increases and if H_2S or CO_2 content is right, corrosion will become a problem, in wells that have no history of corrosion. As a field ages it is a good idea to start checking ph levels and having water samples analyzed. Some other things to watch are as follows.

- Do not run chrome plated pump barrels in wells with a ph below 6.9
- Do not run stainless steel parts if high chlorides are present and the downhole temperature is over 150 deg. F. Use brass or Monel parts.
- Also remember that stainless steel has a yield strength of half that of carbon steel. So be careful of running stainless steel parts in deeper wells. Brass and Monel have higher yield strength than stainless steel and may be a better choice for these applications.

PERFORMANCE DATA

Another cause for confusion is the collection of failure data in days. If you have a group of wells that operate at 10 SPM they are going to complete twice as many cycles (reversals) per day as another group of wells that operate at 5 SPM, yet we still like to compare failure data in days with both groups. I think it is the lack of understanding of how many cycles per day, month and year we put these systems through that keeps this from standing out.

Mean Time Between Failure (MTBF) has been used for so long that it is accepted without question and sometimes can cause data to be skewed and misapplied. The primary downfall of MTBF is that most of the fields operating today have a wide variety of operating conditions from well to well. For example:
At 10 SPM a sucker rod pumping system will complete 14,400 reversals per day multiply that by 365 and you have 5,256,000 cycles a year. This means that the rods have stretched and contracted, the pump barrel and tubing have had the fluid load shifted on and off of them and almost all of the other pump parts have been subjected to stress reversals and wear over five million times in a year.
Mean time between failures. Strokes per minute, different stroke lengths, timers and well controllers as well as a variety of different pumps to meet operation needs make it difficult to apply days in operation as the primary decision making criteria.
Cycle life should be the primary baseline for data and magnitude of reversals should be tied in. All of the components in a sucker rod pumping system have a lifetime but it is measured in cycles (reversals) and the magnitude of those reversals. Reversals and the magnitude of the reversals dictate the normal life of the sucker rods, sucker rod pumps, tubing, polished rods, etc.

Most records will be in days of operation and this data should be converted to cycle time if possible to keep from skewing data. For example let's look at 10 wells with 5 of them operating at 16 strokes per minute and the other five operating at 8 strokes a minute. When added up and averaged in days for run time they will look something like the chart in **Fig. 2.**
The conclusion would be that group 1-5 is not performing anywhere near as well as the group 6-10 and if they were averaged together the average run would drop to 250.1 days.
If we looked at this in cycles per day things would look different. For example; comparing well #1 and well #6 in cycles well #1 had 4,331,520 cycles and well #6 with 2,773,440, well #1 would have out performed well #6 although #6 had the better MTBF.

The load on the system must also be considered because different pump sizes and rod strings, well depths etc. will produce different peak and minimum polish rod loads that affect the cycle life of sucker rod pumping systems. A second chart for each well with the peak polished rod load and minimum polished rod load can be very helpful.

For Conventional Units
(L = Stroke length)

$$SPM = .7\sqrt{\frac{60000}{L}}$$

For Air Balanced Units:

$$SPM = .63\sqrt{\frac{60000}{L}}$$

For Mark II Units

$$SPM = .56\sqrt{\frac{60000}{L}}$$

Figure 1

WELLS AT 16 SPM	RUNS IN DAYS	CYCLES
#1	188	4,33,1520
#2	182	4,193,280
#3	190	4,377,600
#4	176	4,055,040
#5	169	3,893,760
TOTAL RUN TIME AVERAGE	**181**	

WELLS AT 8 SPM	RUNS IN DAYS	
#6	321	2,773,440
#7	333	2,877,120
#8	289	2,496,960
#9	312	2,695,680
#10	341	2,946,240
TOTAL RUN TIME AVERAGE	**319.2**	

Figure 2