Guide to Well Failure Root Cause Analysis in Sour Beam Pumping Service

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Abstract
Production equipment failures in beam pumped wells are an everyday expense in the oil field. Minimizing repeated or unnecessary failures caused by improper design, handling and metallurgy directly reduces the operating expense of any oil company or operator. As the industry downsizes its work force, innovative ways of maintaining or reducing well service costs are becoming more and more necessary. This paper presents a guide to various causes to common failures which are applicable in a variety of service conditions: sour/sweet, shallow/deep and high/low production volumes. This paper is aimed at decreasing over-dependence on technologically advanced equipment, complicated databases and the intensive training needed to assist an inexperienced technician or operator in identifying and diagnosing the root causes of common equipment failures. The guide was developed by personnel from a West Texas operating company and is based upon their five-year study.

Introduction
There are many credible papers in the petroleum and corrosion industries which delve into exact reasons for equipment failures from corrosion, fatigue and obvious handling mistakes. Sometimes these papers neglect to mention the root causes or other influencing circumstances that lead up to the failure. This paper attempts to build on information previously published, add the authors' experiences and determine why a failure happened. Assuming data is not available that describes all circumstances, the authors intend to supply a probable root cause when only the location and sample information is known. This is expected to provide information that would allow an operator to reduce approximately 80% of their failures by highlighting the most likely cause(s).

This paper was compiled from the observation of thousands of equipment failures, wherein virtually every one of the failures was studied for root causes. It should be noted from the knowledge gained during this study that an 85% decrease in failures occurred. Many kinds of data were used to study each failure: historical failure data, chemical treatment data, current equipment design data, fluid level history data, dynamometer data, pump repair data, well bore solids analysis data, rod and tubing string electronic inspection data, and, most importantly, preventive maintenance recommendation follow-through-data. When necessary, metallurgical laboratory tests were conducted to verify failure interpretation.

The authors contend that the vast majority of failures are preventable if the underlying causes are known (even if extensive data is not available). So what is next? The Guide to Well Failure Root Causes Analysis in Sour Beam Pumping Service. This guide will help determine a probable cause with a minimal amount of information and when combined with any additional information, this guide will help expedite the search for the root cause.

The Guide and How To Use It
The important thing about determining, understanding and reducing the root cause of failures is to be methodical and consistent. The following is a procedure that lists the steps needed for failure analysis using this guide. This procedure is presented in the same order that the authors approached each failure except that the authors had an extensive database at their disposal. The guide was created in lieu of a database.

Failure Root Cause Analysis Procedure:
- .Collect failed component sample.
- .Identify the location of sample in its relative position in the string.

.Identify any physical symptoms.
.Compare to Failure Guide to determine probable root cause.
.Implement corrective action.
.Implement long term preventative maintenance program.

Failure Guide:

Collect Failed Component Sample
Sample collection is the first and most pivotal step in solving failures. The added cost to obtain a sample should be considered insignificant relative to the value of the information it can provide. The sample must either be examined in the field by trained personnel or cut to be examined later, assuming the preventative repairs are to be made later. In cutting and examining the failed component, it must be remembered that both ends of the failure are crucial in understanding the failure. Also, sufficient sampling of non-failed equipment is suggested to evaluate whether the problem is isolated or spread throughout the string.

Identify the Location of Sample
The second step is to determine the location of the sample relative to its position in the rod or tubing string. If opportunity allows, the following questions should be proposed during the course of the failure repair job:

.In each rod taper are all the rods the same size, grade and/or batch?
.Is the problem continuous or isolated such as in the case of wear and corrosion pitting?
.Was the tubing anchor set properly, if applicable?
.Did the well servicing crew remove foreign material in the well or on the equipment?
.Did the pump appear to be spaced properly?

Identify Physical Symptoms
The third step involved with the sample is observation of the physical damage on the failed sample. Check for nicks, breaks, scratches, cuts, pits, no pits, etc. Although there may be obvious symptoms from the sample, sometimes the damage may be subtle and hard to find. For example, with rod samples the observation will be 180° from the final tear point.

If possible, compare the physical damage with an undamaged piece of equipment. This can be accomplished by studying other sections of the string or looking at new equipment specification brochures or manuals. This effort confirms the existence of damage. Also, try to compare the sample to samples depicted in the various publications e such as those listed in the reference section.

Compare to Failure Guide to Determine Probable Root Cause
Once the failed equipment sample is identified and examined, the failure guide can be used to isolate several probable causes. The guide should be cross referenced with the following information: type of equipment (including size and grade), location of failure and basic identification of failure pattern. This guide starts with the polish rod and follows with the rods, sinker bars, tubing and pump. Read across to the appropriate symptom and then select the applicable probable cause(s). Further discussion on each type of specific equipment will follow toward the end of the paper.

Corrective Action
With the probable root cause identified, the next step is to correct the problem that caused the failure. Under ideal situations the root cause is determined while a rig is on the well. In this case remedying the problem is simple. Unfortunately this luxury is not always available because people tend to address failures after the fact. Corrective actions are actions that are above and beyond merely replacing failed

components. Corrective actions are those that eliminate the root cause. Sometimes corrective actions are simple, such as resetting a time clock or expensive if using stainless steel instead of carbon steel.

However, corrective action needs to be assigned a value. If the cost of pulling the well to fix the root problem is less than the cost that could be incurred by not pulling the well, the action to pull the well is justified. In some cases the problem may not be assigned a great enough cost value, and the corrective action is postponed.

Work Order Comments may be very useful when corrective action is postponed. Work Order Comments are often used by the authors to remind field personnel that changes need to be made when the well is next pulled. Work Order Comments can be tracked with a database or by simple reminders in well files. In either case they prove to be very useful in reminding field personnel of vaguely remembered past incidences and their corrective actions prior to rigging up on the well.

Long Term Preventive Maintenance Program

The best way to handle failures is by preventing them in the first place through systematic prevention methods. Root cause determination is necessary, but is only the first step in lowering a field wide failure rate. Once the root cause for a particular failure is understood, the operating conditions need to be studied in order to understand which parameters lead to that failure. After tracking and understanding how each factor affects the reliability of the well, failures can be eliminated before they occur by preventative maintenance.

Preventive maintenance means correcting a non-ideal situation before a destructive act occurs. This includes, but is not limited to, replacing worn (non-failed) components, adjusting the rod/pump design, and verifying existing equipment condition. The level of preventive maintenance should be driven by the expected cost involved when equipment fails and production is lost. One can easily see that the cost of fishing parted or mangled equipment out of the well is substantially more costly than replacing it when it is merely worn. The only caveat is that preventive maintenance, if not properly monitored, can cost more than the expected failure it is supposed to prevent.

"Well reliability" is the phrase needed to move the maintenance industry away from the term "failure" to the term "success". The fewer failures experienced translates implicitly to more successes. Longer run times between failures translates into greater successes or longer economical runs. Imagine a one or two barrel a day well being considered an economical well because it creates little or no operational or mechanical expense.

Discussion on Equipment Failures

The following discussions attempt to list the most significant causes of failures by equipment type. The discussions do not attempt to address all facets of equipment failures but address some of the most frequently occurring failures.

Polish Rod Failures

Polish rods are designed with such great mass relative to the rest of a rod string that fatigue failures are generally not a common cause of a polish rod failure. Most polish rod failures, therefore are a direct result of poor handling techniques. Polish rod failures are primarily found in the following situations:

- Mis-alignment of the pumping unit over the centerline of the well head,
- Poor seating of the of the polish rod clamp's base onto the carrier bar,
- Installation of an improper coupling or incorrectly installing of a polish rod coupling onto the pin, and
- General fatigue induced by years of cyclic load stresses.

General fatigue is probably the rarest of these failures because polish rods tend to be fairly massive and thus have low stress loads.

First Sub Under Polish Rod
The first sub under a polish rod is an interesting source of failures. This sub is typically the tool used by well servicing crews to lay down the pumping tee and polish rod. This action bends the sub, allowing a failure to occur shortly after the well is put back on production. The first sub is also the last sub installed on the rod string. Many times the crew finds themselves short one or two subs when trying to space out the pump, invariably, the crew will find an old sub somewhere on their rig and use it as the last sub. This situation may also lead to a failure shortly after the well is put back on production. With this understanding, it is important to pay close attention to the size, grade and condition of the sub(s).

Sucker Rod Failures
Rods are designed to mechanically connect the pumping unit to the pump in order to lift fluids from a wellbore with certain tensile properties that can be categorized into different grades and sizes. Since rod specifications do not include compressional strength, rods should generally be kept out of compression. When designed and operated properly, rods can provide many years of maintenance free life. Rod failures are primarily caused by the following possibilities.

- .Corrosion due to the lack of any inhibition, or due to an ineffective inhibition program,
- .Mis-application of ultra high strength rods in sour service (i.e., hydrogen embrittlement),
- .Improper design for the given conditions,
- .Excessive cyclic loads resulting from a change in condition,
- .Rod versus tubing wear,
- .Mis-handling and/or improper installation techniques,
- .Mis-operation by forcing the pump to tag or by pounding fluid (generally, due to poor gas separation), and
- .General fatigue induced by years of cyclic load stresses.

General fatigue is probably the rarest cause of failure.

Coupling and Pin Failures
Coupling and pin failures are primarily caused by:

- .Insufficient displacement during makeup,
- .Galling of threads during makeup,
- .Corrosion and erosion if the coupling is a basic tee coupling, or if the coupling is not seated correctly on the rod shoulder,
- .Heavy metal loss due to wear against the tubing wall,
- .Stress from multiple make-ups if the well is serviced often,
- .Stress risers caused by tool marks,
- .Over displacement in the case of normal API grade C and K rods, and
- .General fatigue induced by years of cyclic load stresses.

Additionally, the authors find that pins and couplings seldom fail due to over displacement. This problem is simply that most rods are not made up sufficiently and thus insufficient makeup is the primary cause of the failure. The use of displacement cards and controlled rod tongs can eliminate most coupling and pin failures. This observation is primarily applicable to ultra high, and high strength steel rods. Lower strength rods typically do not experience many joint failures except in the case of galling of their threads.

In some cases properly made up coupling/pins can be loosened by the phenomenon of rod slap. Rod slap occurs when the rod and or coupling is slapped against the tubing wall after a pump is set to tag or fluid pound.

One interesting type of Tee coupling failure occurs in high fluid level, high water to oil ratio and high rate wells (effective corrosion inhibition becomes difficult to achieve is difficult to achieve in these wells). It has been observed that when the well is equipped with narrow diameter tubing the couplings can experience erosion. Fluid velocities around the coupling can be as high as 24 feet per second. If the fluid loads are low, the coupling is able to endure metal loss such that one can see through the coupling body to the threads and yet the coupling may still be holding together.

Pump Failures
Rod pumps are designed to artificially lift fluids by lifting it up into a conduit (tubing) while being actuated by the rods. When designed and operated properly, pumps can provide many years of maintenance free life. Most pump repairs are made with the idea that the root cause of a pump failure is in the pump itself. Sometimes this is true, say if frac sand is being produced, or if metallurgy is applied that is not compatible with the fluids being produced. However, most real root causes are due to:

.Poor gas separation causing the operator to struggle with gas interference,
.Poor compression ratio design which results in gas locking of the pump forcing the operator to tag the pump to produce the well, and
.Grossly over producing a well in order to make a little more production (i.e., at ten hours run time per day the operator can produce 10 barrels, but at 20 hours per day he can get 11 barrels).

The severe impact forces generated by tagging or fluid pounding do more harm to a pump, rods and tubing than any other failure inducing influence. Poor gas handling design and the desire to gain "just a few more barrels of oil" are the primary root cause for the perceived need to tag or fluid pound a pump. Traveling valves, pull rods/tubes and guides produce strong evidence that the well is being mis-operated.

Tubing Failures
The role of tubing is to be the specific equipment that allows the movement of hydrocarbons from the perforations to the surface. This requires the tubing to have two specific strength properties: tensile and burst. With very few exceptions, one being deep wells, the tensile strength of tubing (assuming a minimum yield design) does not cause many failures, however burst failures are noted for being the majority of the tubing body failures. Tubing failures are caused primarily by:

.Excessive rod wear,
.Corrosion pitting,
.Erosion/Corrosion on the bottom joint,
.Hydrogen embrittlement of non-normalized ERW tubing, and
.Mis-application of high tensile strength tubing in sour wells

Rod wear is the most common cause of tubing bursts or splits. Thus rod wear most often occurs when:

.Compressive loads that buckle in rods,
.Rod and tubing contact in deviated wells,
.Rod and tubing contact when either the rod(s) and tubing joint(s) are bent,
.When insufficient tension is applied to the tubing anchor and
.Tubing movement due to the lack of a tubing anchor.

The only exception to this, which the authors' noted, was where a split occurred even though there was little wall loss. This was isolated to non-normalized electric resistance welded (ERW) seamed pipe that failed from hydrogen embrittlement. Excessive tubing movement can easily be remedied with the use of a tubing anchor. Rod wear failures can also occur toward the bottom of the string where rods are most often in compression. This type of failure can be minimized or even eliminated by designing the rod string with a minimum amount of compression (this should additionally help the life of the rod string). Continual rod wear in one area is a good indicator of a deviated well. The remedy to this predicament is unclear, but the damage may be minimized by the use of rod guides and/or a tubing rotator.

Corrosion pitting can also be the source of failed tubing. Generalized corrosion pitting by itself can easily be eliminated by an effective corrosion inhibition program. Although it would seem that corrosion pitting should be somewhat uniform over the length of the string, failures most often occur toward the bottom of the string. This is due to the produced fluids at the bottom of the well having a lower pH compared to the produced fluids at the surface. This is exacerbated by the influence of rod wear at the bottom of the well. This failure can be minimized through enhancing the chemical program and through redesigning the equipment to reduce wear.

Bottom joint failures, being one of the more common failures observed by the authors, are classified as neither a rod wear split nor a corrosion pitted hole. Bottom joint failures most often occur in one of two ways: erosion from pump discharge or pitting due to corrosive and stagnant fluid below the pump discharge area. The authors noted that this situation most frequently occurred in stripper wells were the well spent a great deal of time shut down (corrosive water settles to the bottom of the well). After trying numerous ceramic, plastic or epoxy lined joints, the authors observed that the most effective way to prevent the above mentioned bottom joint failures was to utilize 316 stainless steel subs for both the pump discharge and the stagnant area. Although the initial expense is considerable, the expected life for the bottom joint went from as short as eight months to four years and beyond.

The tubing pin and the collar will be discussed together since they are dependent on each other. The pin most often fails from physical damage to its threads. This situation can be caused by galling of the threads, leaving a weak and leaky connection. However the collar failure can be classified in one of four ways:

- .Striated deterioration (due to tubing movement),
- .Vertical split (hydrogen embrittled collar),
- .Diagonal split (over-displacement of pin and collar), or
- .Galling (from either thread damage on pin or collar).

With proper collar handling and pin inspection, collars and pin failures should be rare.

It should be noted that when examining tubing for failure symptoms, it is important to inspect both the inside and outside of the tubing to fully understand the origin of the failure. This effort differentiates between what appears to be a hole due to corrosion versus a hole due to rod wear. It would also be helpful to examine as long a section of the joint as possible to determine the extent of the damage.

Validation of Probable Root Cause

The guide can give a probable cause when only limited information is available and should be correct at least a majority of the time. To resolve the probable root cause more often with even more authority, one must additionally use certain types of resources made available to the authors. One of the more comprehensive resources used by the authors was a complex database which tracked well servicing, chemical, pump, general well information, production tests and fluid levels. A general rule to follow in validating the probable root cause is that the more information available, the easier it will be to finalize a root cause.

The authors' experience suggests that the manufacturer, the service company,or their representative, and the manufactured component are usually the last real causes of equipment failures. The least of these root causes is the quality of the manufactured component. Our study of failed components found very few, in fact less than one percent of manufacturing defects led to failures.

Most failures are actually caused by human error which includes the errors of engineers, operation supervisors, well servicing crews and lease operators. The ways in which human error can affect the life of equipment is as follows:

- .Engineers who improperly design or apply equipment that is not intended for specific well

conditions,
.Operation supervisors who fail to fulfill prudent preventative maintenance decisions,
.Well servicing personnel inadequately supervised, trained and equipped to handle equipment while servicing a well, and
.Lease operators who may not fully understand the hydro/mechanical function of a rod pump and tend to grossly over pump a well or set the pump to tag.

Following human error, the second most likely cause of downhole equipment failure is well environmental conditions. The conditions that contribute to well equipment failures include corrosion, gas interference, inconsistent liquid/gas flow from the reservoir and high fluid levels. Each of these conditions may induce additional stress above and beyond mere fatigue stress. These conditions can be accommodated by designing around the unfavorable conditions, if not, they may fall into the human error cause.

Conclusion
The Failure Guide to Determine Probable Root Cause was created to provide the inexperienced and experienced alike with a list of probable root causes to many of the petroleum industry's beam pumping problems when only a limited amount of information is available. When it is used to understand why equipment fails, new and/or repeat failures can be prevented, which in turn will make more wells more economically sound due to decreased repair costs and lost production. It should be noted that this is the authors' first attempt to organize the knowledge attained from the study of failure root causes, therefore future revisions and updates can be expected.

Acknowledgments
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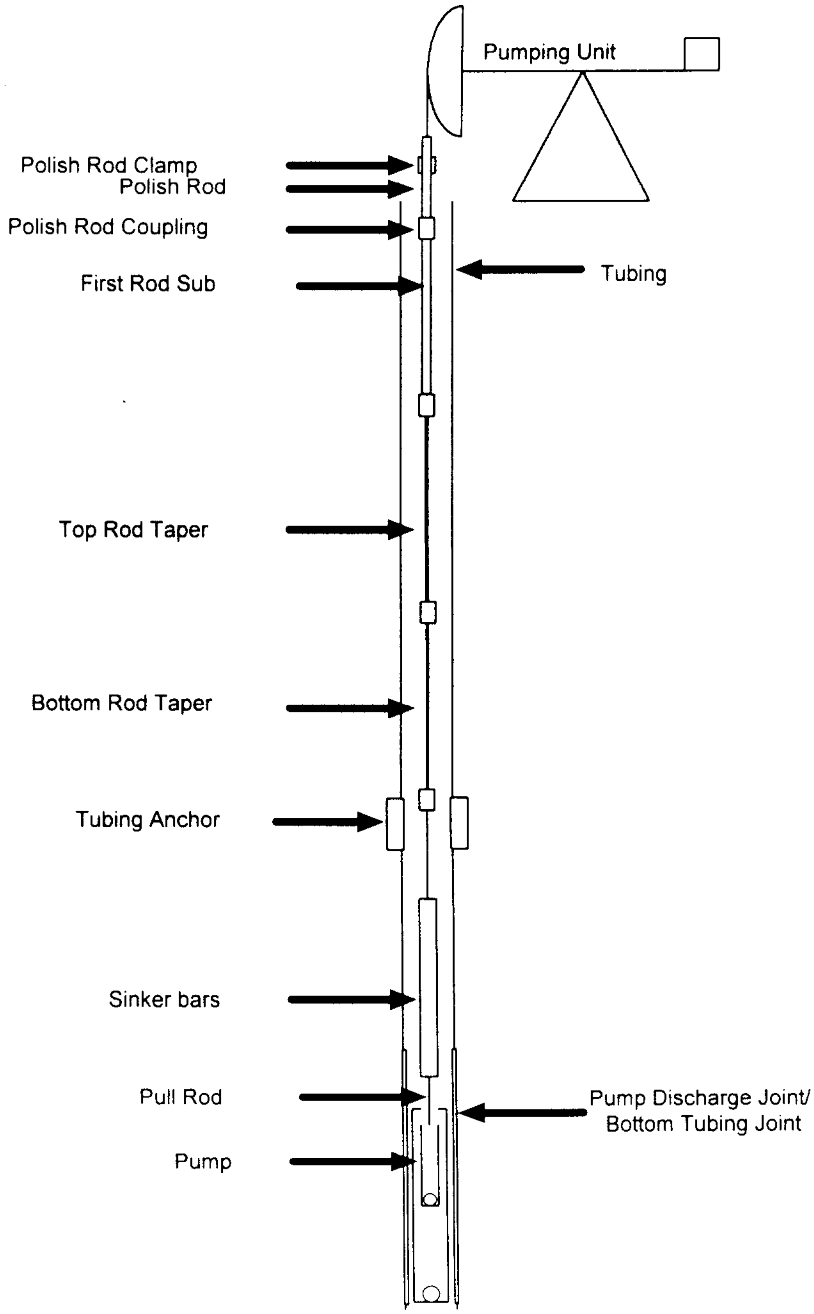
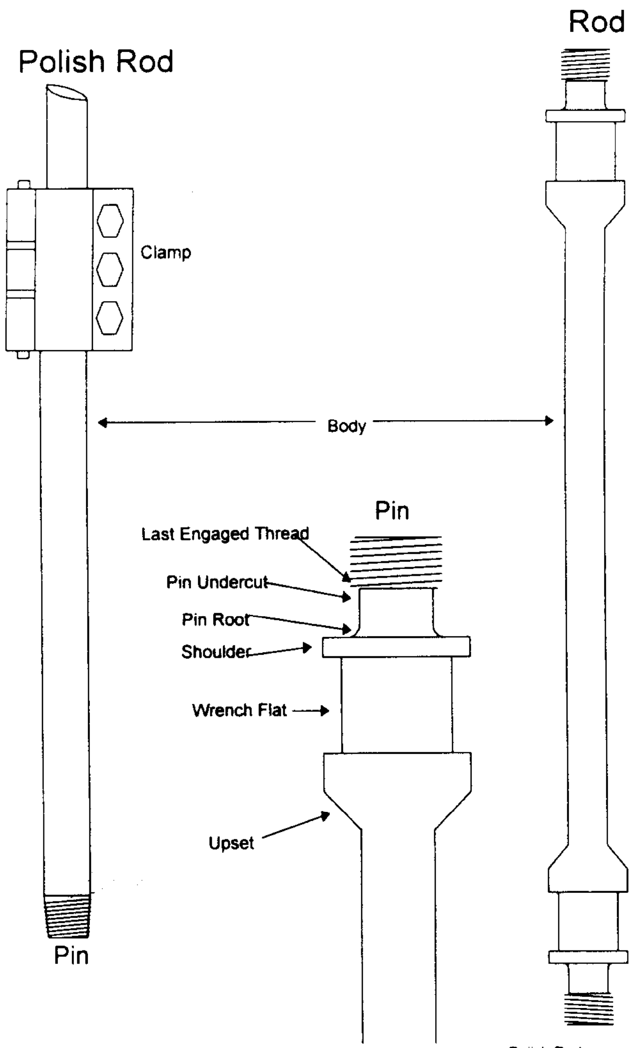
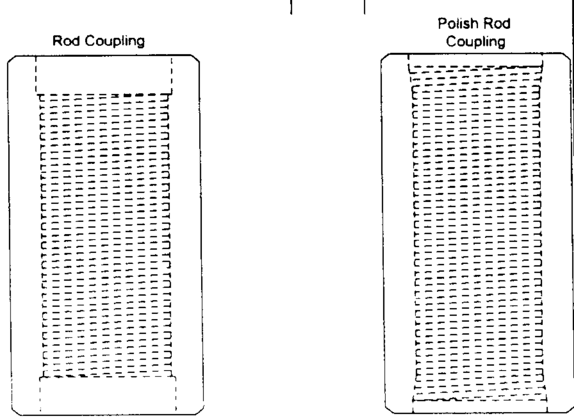


Failure Guide Overview



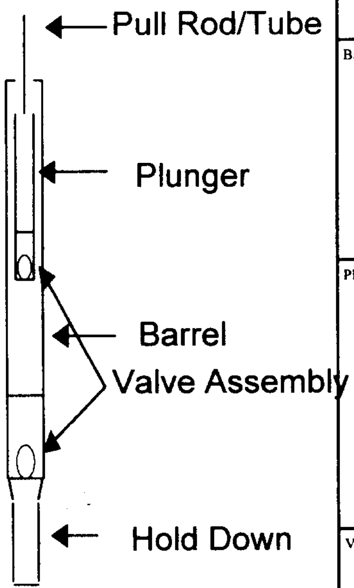


Failed Component		Symptoms		Probable Root Cause
Polish Rod	Body	Break immediately below clamp		Spray metal coated. Clamp was tightened on spray metal section
				Misaligned Clamp
		Break anywhere else below clamp		Body bent
				Pumping unit not aligned over wellhead.
	Pin	Break		Pin breaks are rare due to its relative size and strength
	Coupling	Split vertically		Coupling over torqued
				Polish rod coupling not used.
1st Rod Sub Under Polish Rod	Body	Break	upset	See Rod Part 2
			away from upset	Sub bent most likely from well servicing crew when laying down polish rod/stuffing box
				Use of damaged or weakened sub when spacing well
				Excessive loads relative to size. See Rod Part 2
	If other see Rod Part 2			

Failure Guide - Rod Part 1

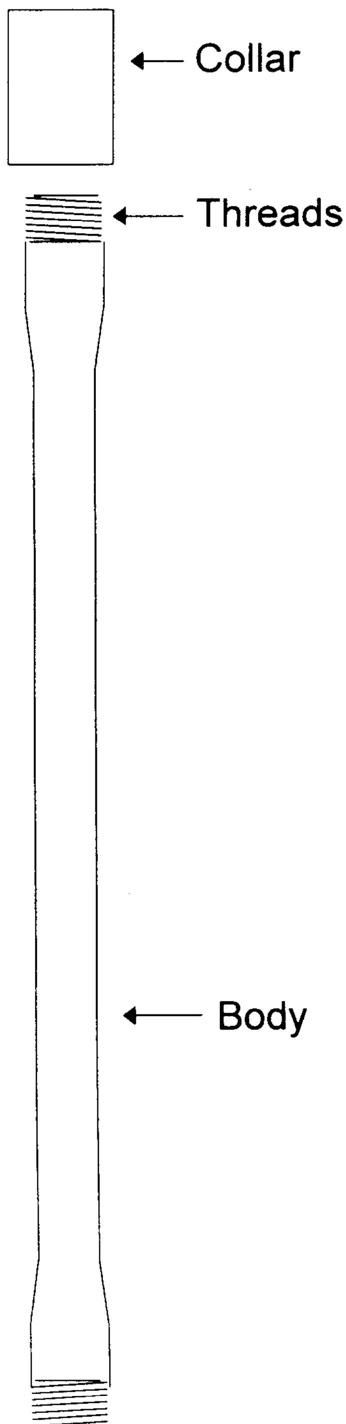
Failed Component		Symptoms		Probable Root Cause
Rod	Upset	Break		Elevator damage.
				Rod table not aligned properly.
	Body	Break	w/no visible damage	Cyclic fatigue.
				Ultra high strength rod in compression.
				Embrittled high strength rods.
				Ultra high strength loads in excess of rod strength.
			tensile elongation	C, D, & K grade rods: Loads in excess of rod strength by design or pump sticking.
			w/small nicks and wrench marks	Handling
			w/small pits	Ultra high strength rods: Corrosion induced H_2 embrittlement and sulfide induced stress cracking.
				C, D & K grade rods: Loads at or near rod strength with mild corrosion.
			w/moderate to severe pitting	Ultra high strength rods: Rods will normally fail before large pits occur.
				C, D & K grade rods: Severe hydrogen sulfide corrosion.
				All grade rods: Sulfate reducing bacteria attack.
			bent	Dropped and bent during previous failure.
				Handling.
			spalling	Cased hardened ultra high strength rods: Caused from H_2 embrittlement affecting the cased hardened area.
			twisted (45 degree break)	Torsional break caused by repeated rotation of rod without proper stress relief.
			wear w/no pits	Tubing anchor has insufficient tension.
				Well has excessive deviation.
				Rods are in compression (e.g. rod slap) by mis-design or from fluid pound or pump tag.
			wear w/pits	Same as above plus ineffective chemical program.
			=<6" from shoulder	Rod slap caused from severe compressional loads.
	Pin	Break	last engaged thread (first thread above undercut)	Insufficient coupling displacement during previous job, or the coupling is slapping the tubing causing it to back off.
				Fatigued pin if time period between first pin failure and original installation is significant.
			pin undercut (root)	Cased hardened ultra high strength rods: Insufficient coupling displacement during previous job.
				Mechanical damage on surface of pin undercut.
			shoulder	If spalling suspect manufacturer's defect on cased hardened rod.
			wrench flat	Rod wrench damage from previous pull.
		Galled	threads	Cross threaded by well servicing unit
	Coupling	Break	last engaged thread	Insufficient make-up, or the coupling is slapping the tubing causing it to back off.
			center	Fatigue caused by wear, or loads Ineffective corrosion inhibition. If coupling steel is hard, and well has H2S, then possible corrosion generated hydrogen induced stress cracking
			nick or wrench mark	Handling.
			erosion corrosion	Tee couplings: High fluid velocity and corrosive fluid.
			wear	See rod body wear w/no pits
		Split	vertically	Over displacement of a soft steel coupling, or coupling packed with foreign matter prior to make-up during previous job
Sinker bar	Body	Break	w/no pits	Fatigue
			w/ pits	Ineffective corrosion inhibition program
			wear	It is rare for a sinker bar to fail from wear
	Neck/Sub	Break		Fatigue from insufficient neck diameter or stiffness for the existing compressional loads
		Bent		Rodstring previously dropped
	Pin	Break or unscrewed		Severe compressional loading with insufficient make-up

Failure Guide - Rod Part 2



Failed Component		Symptoms	Probable Root Cause
Pull rod/tube	Upper Pin	Break w/Beat Clutches or Adapter	Repeated tagging caused by improper spacing either when the well servicing crew spaced well or when rods were lowered to get pump "pumping"
		Break w/o Beat Clutches or Adapter	Fluid pound
	Lower Pin	Break w/bend at lower end of pull rod/tube	Pull rod/tube telescoped out when picked up by well servicing crew.
	Guide	Beat	See upper pin
		Worn	Fluid pound
			Worn pull rod/tube
	Body	Break	Fatigue
		Break w/wear	Bent pull rod/tube
			Fluid pound or a sticking pump
			Worn over time.
Barrel	Body	Grooved or scored (multiple shallow grooves)	Single foreign object, most likely metal, lodged between plunger and barrel.
			Foreign material such as sand, iron sulfide, or if in sour service, flaked chrome plating.
		Hole	Steel barrel: Ineffective corrosion inhibition or galvanic corrosion
			Brass barrel: Severe internal wear.
Plunger	Body	Break with pitting	External: non spray metal plunger in sour service.
			Internal: Ineffective corrosion inhibition program or galvanic corrosion.
		Break w/o pitting	These are rare.
		Grooved or scored (multiple shallow grooves)	See barrel body
	Pin	Break	Manufacturing defect caused from improper welding or joining of pin to plunger body.
Valve assembly	Seat	Crack or chipped	Fluid pound and/or incompatible ball and seat metallurgy
	Ball	Pitting	Ineffective corrosion program, or abrasion
		Wear	Abrasion over time
	Cage	Beat	Travelling valve: Fluid pound
			Standing valve: High pump intake pressure
		Break	See cage beat.
			H2 stress crack
		Pitting (with or without break)	Ineffective corrosion inhibition on carbon steel
			Galvanic corrosion if used in conjunction with galvanically incompatible metallurgy
Hold down	Mechanical Type	Fluid cut	Worn or ill-fitting seating nipple
	Cup Type	Torn cups	Multiple seating and unseating of pump
			Damaged when ran in well.

Failure Guide - Pump



Failed Component		Symptoms		Probable Root Cause
Upper Section of Tubing String	Body	Hole	Rod wear w/no pitting	Extremely deviated wellbore.
				Bent tubing joint or rod.
				Coupling "bite" at end of stroke on tubing ID. Most likely results in crescent shaped hole or split.
			Pitting	Ineffective corrosion inhibition.
				Sulfate reducing bacteria.
			General or uniform corrosion deterioration	No or ineffective corrosion inhibition.
			Internal pitting w/wear	Possibly all of the above.
		Split	Vertical w/wall loss	Excessive rod wear. See hole w/rod wear.
			Vertical w/minimal wall loss	ERW pipe seam or near seam breaks due to improper or insufficient normalization.
		Bent		Improper handling.
				Tubing dropped in well.
	Pin	Galled		Improper make-up
	Collar	Galled		Same as above
		Split	Vertical	Stress crack caused from hydrogen embrittlement of possibly improper metallurgy.
			Angled	Over-displacement of tubing and collar by well servicing crew.
		External wear or deterioration		Tubing movement.
				Severe external corrosion.
Lower Section of Tubing String	Body	Split or hole	Wear w/no pitting	Excessive sinker bar or rod wear due to excessive compression in rods or bars.
				Tubing anchor set in compression.
			Other	See Upper tubing section.
Pump Discharge/ Bottom Joint	Body	Hole		Bare steel: Typical erosion/ corrosion failure caused by pump discharge. IPC, Ceramic coated: Similar erosion corrosion failure occurring in holiday in close proximity to pump discharge.
		Split	Vertical w/wear	Severe wear usually caused by compression on pull rod.
			Vertical w/score	The spiral guide has a burr or other imperfection that is damaging the joint.
			Horizontal	Pump barrel may be equipped w/ a centralizer ring.

Failure Guide - Tubing