MANAGING SOLIDS IN ROD PUMPED WELLS

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Solids in rod pumped wells contribute to increased operating costs and are often overlooked as a program to be managed. There are significant opportunities to reduce wear and improve corrosion protection by addressing solids management more proactively.

TYPES/SOURCES OF SOLIDS: Solids that are produced in rod pumped wells come from the formation and from postproduction sources. Solids from the formation can include friable sands, fines that are freed from stimulation processes, and flowback of proppants. Postproduction solids can include weathered scales from inside tubing, scales from the outside of the tubing, and solids that are pumped down the well from the surface. The solids from the surface can come from anything pumped down the casing by tubing annulus, continuous treating slip streams used to displace chemicals down the well and worn packing from the downstroke of the pumping unit that moves through the continuous treating slip stream.

<u>Properties of solids:</u> The physical properties of most solids that are eventually produced to the surface are detrimental to downhole operations. Select physical properties of common oilfield materials are shown in Table I. The specific gravity of typical downhole solids ranges from 2.7 to 4.8, all of which are dramatically heavier than water or oil. These density differences with oil and water make the solids hard to produce. While the minerals, sands, and scales have less strength than steel, their hardness acts as an abrasive to steel. The strength of minerals is misleading because their strength is dependent on the pressures, temperatures, imperfections when they were formed, and particle size. Smaller particles tend to have greater strengths.

The hardness of solids is difficult to compare with downhole equipment because the scales do not readily convert. The hardness of minerals is commonly on a Mohs hardness scale. This test is a scratch resistance test on a scale of 1-10 with diamonds having scratch resistance of 10 on the Mohs scale. The hardness of downhole equipment is a measurement of indentation under specific test conditions. Because of the wide range of materials and applications, there are numerous hardness indexes including Shore, Brinell, Rockwell A, Rockwell B, Rockwell C, Vickers, Knoop, etc. Each scale is based on different indentation testing criteria and ranges. Rockwell C hardness is a common index for various steels, but new materials and surface treatments exceed the Rockwell C range. For ultrahard steel alloys, the trend has been to use the Vickers scale. Table I shows the material hardness for the most pertinent materials in downhole processes on the Vickers scale. The quartz sand samples that were tested were from Arkansas.

FAILURE ANALYSIS: The study of wear, friction, lubrication, and failures of surfaces in relative motion to one another is known as tribology. In the oilfield, this area of study is simplified into broad categories, including corrosion, corrosion-wear, wear-corrosion, and wear. Unfortunately, these categories are oversimplified into just corrosion and wear. Holes in tubing, for example, are categorized as corrosion while splits are categorized as wear.

Unfortunately, wear in tribology is a specific type of metal-to-metal galling that presents itself as a polished surface. This type of failure is seldom seen in downhole rod pumping failures.

Downhole wear in the oilfield is result of stress risers that create conditions where the shear strengths of the steel surfaces are exceeded. These stress risers are the result of solids or corrosion undercutting occurring in the same channel thousands of cycles per day at a microscopic level.

Solids concentrate side loading forces where solids are trapped between the surfaces. The cross-sectional area at the point of contact is so small that stresses are amplified. These wear profiles present themselves as striations in the contact area. These striations, for example, are commonly seen in the top 18-24 inches of plungers.

Corrosion is a more complex contributor to wear at the interface of two metal surfaces. Active corrosion results in microscopic oxides being formed on every stroke. These oxides have minimal shear strength. As a rod box contacts the tubing, the oxides are removed or worn away. The second process by which corrosion creates a wear profile is undercutting at a microscopic level. Undercutting increases stress by removing material and leaving “pinnacles” of steel with small cross-sectional areas that can be sheared away. Each of these corrosion processes happens over thousands of cycles per day and create wear patterns that develop into a channel.

Traditional corrosion failures are defined as a loss of metal/pitting that continues below the contact surface area of the metal contact areas. True corrosion failures are independent of the cycles per day. However, since corrosion may have been initiated along rod by tubing contact area, orientation of the corrosion can compound the channel profile of the overall failure.

Whether the corrosion is deep or shallow, the resulting corrosion by products add to problems with solids. Iron sulfide has a high specific gravity (4.8-5.0). Until the iron sulfide is removed from the well, these solids add to the stress riser problem. In effect, corrosion results in more solids in the well and more solids lead to more corrosion. Field personnel rarely have the time or the tools to properly analyze the more specific failure category.

LIFTING SOLIDS: The process of lifting solids from the well is a complex interaction of the fluids with the solids being lifted via the fluid velocity created by the rod pumping system. There has not been significant industry research regarding the critical flow rates required to lift solids in rod pumped wells. There has been some research regarding water slurry systems in horizontal piping systems. Table III shows the relationship of critical velocities versus the size of the particles in horizontal slurries. These systems are typically for continuous pumping pipeline systems.

The critical rates in vertical rod pumped wells are much more complex to estimate. The rates vary within every stroke and may be off for periods of time. The effective viscosity of the dynamic oil-water-gas mixture is not easily defined. Relative slippage between the solids and the liquids is yet another challenge. Despite these problems, the critical rates are expected to be less than the horizontal water slurry systems because of the increased effective viscosity. Consistent with the water slurry estimates, vertical critical rates are expected to be less for finer particles.

The implication of the critical rate versus particle size has important implications for failure analysis. High specific gravity solids will fall inside the tubing repeatedly until they are ground fine enough to be removed from the well. The tumbling of solids is more pronounced at the bottom of the well and until solids are reduced in size. This process creates a concentrated "cloud" of solids that accelerates the destruction of the inhibitor films in the bottom of the well. In effect, there is simply more sandpaper present in the bottom of the well.

Field experience demonstrates confirms this tumbling process. Continuous treating diverts a portion of the production from the pumping tee through the 1" side back down the well to flush chemicals down the well. Restrictor valves are known to plug with solids every few days, diminishing the effectiveness of the chemical program.

A filtering system was installed on a flush line from the pumping tee. Table II shows the results of filtering the flush fluid in a continuously treated well. The solids fairly represent the solids produced from the well. There are no chunks recovered in the filter and most of the solids by weight are finer particles, strongly suggesting the tumbling of larger solids deeper in the well.

There are other operational experiences that further confirm the tumbling/grinding of solids deep in a well. Increasing striations with depth are common. Plungers often exhibit severe scoring in the top 18-24 inches of the plunger. As production rates decline and more solids are expected to fall, there are greater problems with sticking pumps. In fact, many operators try to make sure the pumping unit is slightly heavy when the well is off, so the first movement of the plunger is downward when the pumping unit starts. Instead of pulling solids into a friction bind, the solids above the plunger are driven into a slurry condition. Collectively, these operational experiences confirm the increased grinding in the section above the pump.

STRATEGIES TO REDUCE SOLIDS: There are numerous strategies to reduce the downhole solids that now accelerate the failure of downhole equipment.

Chemical programs: The most common techniques to reduce solids are effective chemical programs that prevent the formation of mineral solids and corrosion by-product solids. Batch treating programs have been widely discredited. For continuous treatment to be more effective, greater deployment of flush filtering is an important improvement operators can implement. The filter used for the results in Table II lasted more than 90 days (about 3 months) before needing to be serviced. Not only were the solids removed from the system, but the needle valve also no longer plugs up, increasing the frequency when continuous treating standards are reached.

Improving continuous corrosion inhibitor treatments will reduce the formation of more solids. For example, there are no known corrosions inhibitor films that can withstand the shear stresses of simple downhole side loading, let alone shear stresses from stress risers induced by solids. Hundreds of "windows of corrosion" are opened at virtually every contact point between rod boxes and tubing. For continuous treatment to be effective, continuous flushing must be achieved. Without continuous flushing, windows of corrosion cannot be continually refilmed.

Desanders: Helical desanders may need to be redefined to include their use to remove any solids that enter the pump.

Ultra hardened Tubing (Boronizing): This gas diffusion technology with boron creates an extremely hard and corrosion resistant surface that reduces rod wear. In addition, the relative hardness compared with typical solids should accelerate the breakdown of solids to finer sizes.

Milling Rod Guides (MRGs)**:** This patent pending technology is expected to deploy multiple ultra hardened rod boxes on pony rods with jackets of sacrificial anode material. The primary goal of this technology is to create a milling system alongside boronized tubing that more effectively crushes solids before the solids damage the tubing rods. Using a series of guides distributes the loads to minimize the risks of metal-to-metal failure mechanisms while capitalizing on the relative hardness contrast with solids. As Table III suggests, downhole solids are generally weaker than steel. However, the solids have been much harder (i.e. more abrasive) for decades. Ultra hardened materials at the contact points can now reverse this relative hardness problem and create areas where the alloy surfaces are harder than the solids, accelerating the crushing/tumbling of the solids. The second objective of MRGs is to provide an instantaneous alternative corrosion mitigation process as a rod guide. MRGs are expected to reach the market in 2024.

Changing failure analysis: Focusing on reducing solids can improve failure analysis problems across the industry. Currently, root cause failure analysis by many companies tend to make operators and chemical companies determine the primary failure and primary solution to emphasize rather than more wholistic assessments. For example, deep tubing failures that present themselves externally as splits are commonly attributed to wear. Chemical companies assert they cannot control wear. A detailed internal analysis of many of these failures, however, indicates a failed corrosion program that allowed repetitive corrosion-wear to accelerate to failure. A significant number of internal reviews also indicated that deep corrosion under the corrosion wear channel was a major contributing failure mechanism. Finally, many of the failures indicated a combination of relatively shallow pitting that would result in undercutting stress risers while deep pits were developing in other areas of the same general channel that were purely corrosion cells, unrelated to the corrosion-wear areas. This last mechanism is perhaps the most troubling. While the initial failure at the contact surface was attributable to solids, the ultimate failure was deep corrosion along the root of other striations. Even in the stress riser striation areas, the corrosion inhibition was destroyed along the striation. Collectively, all of the evidence from the inside indicated corrosion was the leading problem while the simple analysis from the outside indicated "wear". The sandpaper like destruction of corrosion inhibitor films was potentially lesser part of the overall failure assessment.

Historical lessons: There are significant historical lessons that need to be part of failure analysis training to better assess the value of specific mitigation programs.

The failure history of rod pumps driven by gas engines is one such historical lesson. Prior to electrification, pump off control, and higher water cuts, gas engines were run continuously and were over pumping the wells, resulting in severe pounding and/or tagging. These wells did not experience high failure rates because of so called metal-to-metal wear mechanisms. The high oil cuts immediately healed the windows of corrosion on every stroke and provided lubrication. Once higher water cuts were common, mineral scales and corrosion related solids increased and failure rates increased. When wells were electrified and pump off control was applied, failure rates declined. However, the history of gas engine operations suggests the greater problem was the systematic, repetitive inhibitor film destruction without effective programs to heal the exposed windows of corrosion.

Similarly, the historical industry experience with sacrificial rod guides is a macro example of solids-like failures. The original rod guides were effectively a type of large-scale solids that were snapped onto the rods and were free to move up and down the rod's body. The material strength and contact area of the guide were not considered capable of damaging the rods or the tubing. And yet, the Snap-on guides were a spectacular failure. The guides were so effective at destroying the corrosion inhibitor films where the rod bodies contacted the guides that large sections of rods were reduced to the diameter of pencils before finally failing. Again, “solids” effectively stripped the inhibitors on every stroke without an effective program to continuously heal the windows of corrosion.

The history of rod couplings is another lesson that is still unfolding. Spraymetal couplings were developed with polished surfaces and much harder properties to combat rod wear. However, SMCs were still not harder than solids. The offset tubing was softer material. Stress riser analysis across both steel surfaces and the solids in the impact zone suggested that crushing of solids was only modestly affected while more of the stress riser effects were carried to the tubing. Many operators experienced increased tubing failures and no longer use SMCs. MRGs are an effort to overcome this problem by focusing the stress risers on the solids while both steel surfaces are harder than the solids.

Molded rod guides offer yet another lesson regarding the handling of solids. These guides are made of sacrificial plastic that wears out over time. While they are working, molded rod guides are softer and allow solids to embed in the plastic, thereby reducing the stress on the tubing being contacted. Although this attribute is helpful, the contact area is also very efficient at removing the corrosion inhibitor film from the tubing. If the corrosion inhibitor film is not reestablished, the thousands of cycles of stripping create a channel that gives the appearance the guide is cutting the steel with the impression of a channel. The channel is the area where corrosion oxides are being repeatedly removed and a fresh window of active corrosion is created. Solids freed from this type of stripping may be very small and may be produced with the fluid. To extend the life of each fin on the guide and to spread out the corrosion-wear area on the tubing, rod rotators are commonly used.

<u>Economic impact of solids:</u> The impact on operating costs from solids are widely distributed. There have been tens of thousands of damaged plungers. The number of stuck pump interventions is dramatic but not tracked at an industry level. The solids related wear in tubing and rods is overwhelmingly proven. Apportioning the costs is a continuing problem for industry. Younger professionals that rarely experienced low failure frequencies in severely over pumped wells with gas engines and high oil cuts tend to attribute failures to pounding and pump off events. Chemical companies prefer this approach. Older professionals tend to focus on the problems with increased corrosion rates and solids as water cuts increase. These differing perspectives change the emphasis of possible solutions. The first perspective favors increased automation and control of pumping conditions. The second perspective favors more effective chemical treatment efforts. Neither approach should be exclusively applied.

Unfortunately, increasing water cuts, increasing solids, and manpower trends have reduced the effectiveness of chemical programs over time. The plugging of needle valves on the flush part of treating program has become so common that cycling the valve to clear the solids needs to be done on-site every few days for many wells. Frequent on-site maintenance, however, is contrary to increased automation and reduced on site time for lease operators.

The plugging of the needle valve is so severe in some areas that one chemical company developed a full opening motor valve system that will not plug. The process is not the same as continuous flushing, but frequent small slugs of flush are far more effective than plugged flush lines that may go unnoticed for days or weeks. Unfortunately, the technique implicitly acknowledges the solids in the system are being discharged down the well rather being removed from the system.

Although the total costs to the industry of managing solids can readily be acknowledged, the cost-benefit of individual solutions is difficult to isolate, partly because of historical and current technical biases. Champions of one so-called “best practice” tend to diminish the value of other approaches. Fortunately, applying a mix of all solutions is far less costly than rig interventions.

<u>INDUSTRY ANALOGIES:</u> Comparisons with another industry may demonstrate the costs of not effectively dealing with solids. Since a downhole pump can be thought of as a single cylinder piston, comparisons with internal combustion engines (ICE) might be helpful. Assuming a 25 mph average speed over the entire life of the engine run time, a 200,000 mile life, and a 3000 RPM engine speed, each cylinder is cycled 1,440,000,000 times. To achieve this life, internal combustion engines use relatively hard materials for piston rings, cylinders, and liners. Oil with corrosion inhibitor is continuously running through the engine. The oil is continuously filtered with an oil filter that typically can extract 95% of the solids greater than 40 microns and is repeatedly changed. In a related study on both diesel and automotive engines, General Motors is reported to have commented, “compared to a 40-micron filter, engine wear was reduced by 50 percent with 30-micron filtration**.** Likewise, wear was reduced by 70 percent with 15-micron filtration**”** (Noria Corporation 2024 online training)

By comparison, a hypothetical well pumping at 8 SPM for 5 years before failing would cycle only 4,032,000 times or about 0.3% of a single automotive engine piston. Without question, this comparatively poor performance is partly attributable to the nature of the fluids being produced, the geometry of the wells and various other operational considerations. However, the relatively poor performance of an oil well can also be improved with more attention to managing solids. No one would consider running their car or truck without an oil filter or throwing a handful of grit into the crankcase on a regular basis. And yet, the oil industry has effectively carried out these practices for decades. The target for expense reduction is significant.

Managing solids involves a concerted effort to prevent solids from forming in the first place, continuously mitigating corrosion related solids, and processing the solids out of the well more efficiently.

Table I: Select Properties- Oilfield materials

Material	Hardness (MOHS)	Hardnes (Hv)	Specific Gravity	Strength (psi)
Sand	7	1050 ***	2.6-2.8	12000-24000*
Limestone	3		2.3-2.7	6000*
Dolomite	4		2.4-2.8	6000*
Shale	3		2.4-2.8	15000*
100 mesh sand	7		2.2-2.8	12000*
Calcium Carbonate	3		2.7	6000*
Iron Sulfide	6		4.8-5.1	
L-80 tubing	6	300***		48000**
Boxes-Regular		250***		
Boxes-SM		700***		
Boronized L80		1500-2000***		
Boronized Boxes		1500-2000***		

*Compressive Strength
**Shear, 60%+- of Tensile
***Provided by Bluewater Thermal Solutions

Table II: Slip Stream filter analysis.

Mesh size	Dry weight (Grams)
30	56
50	172
80	66
	81% < than 30 mesh

Table III: Horizontal water slurry critical velocities*

Mesh	Critical Flow Velocity (ft/sec)	Approximate B/D
4-20	7-11	3200-5100
20-200	5-7	2300-3200
Over 200	3-5	1400-2300

*Engineeringtoolbox.com
** 2-7/8" tubing by 7/8" rod annulus