ARTIFICIAL LIFT EQUIPMENT TESTING AND REPLACEMENT GUIDELINES

Joel Gallegos, Steve Gault, Rynn Peeler, Steve Reedy,
Jim Seery Jr., Calvin Stewart, and Saul Tovar
Occidental Petroleum

The following guidelines for replacing downhole equipment for beam pumps were compiled in a series of Root Cause Failure Analysis (RCFA) schools conducted in 2017-2018. They were vetted by a cross-functional group of experienced stakeholders and are summarized below. These guidelines should be used when field experience supports these policies and procedures.

TUBING

Bare Tubing

All new tubing should be Full Body Normalized After Upset Electric Resistance Welded (FBNAU ERW) or domestic seamless (SMLS).

Yellow- and blue-band tubing should be used in all applications, if available. Yellow-band tubing has a maximum wall loss of 15%, and blue-band tubing has a maximum wall loss of 30%. An acceptable wall loss is 0.05” for both. This size pit can best be visualized as the end of a ballpoint pen or a measurement of 50 thousandths using a feeler gauge.

Techniques for assessing the quality of used tubing include: 1) visual inspection, 2) laying down and inspecting tubing in the yard, and 3) mechanical inspection. The decision to inspect, scan, or hydrotest tubing should take into consideration the well’s history and downhole configuration. The age of the tubing is not a criterion considered when assessing the quality of steel tubing that has not exceeded its stress fatigue limit.

Visual inspection is used to identify when tubing should be fully inspected, scanned, or hydro-tested for corrosion losses. Wellhead scanning has fallen out of favor for this purpose. Note that hydro-testing is used to evaluate the ability of tubing to hold pressure at that point in time; it is not a measure of the tubing quality or a reliable indicator of metal loss.

Laying down the tubing in the yard for full inspection is the accepted method of assessing the quality of tubing.

On-site tubing inspection and leak identification is done in several ways:

- Dropping a standing valve and pressurizing – Some engineers drop a standing valve and test the tubing to 1000 to 2000 psi. If this test fails, they hydrotest.
- Hydro-testing – The recommended maximum pressure for hydro-testing bare tubing is 80% of the burst rating or 6000 psi, whichever is less, then holding for a minimum of 5 seconds. Note that water used for hydro-testing should include bactericide.
- Cutting and visual inspection – This is an alternative to scanning on location. Using a pipe cutter and tubing tongs, cut 18” from the pin end, and cut every 1000 ft and inspect. Should the inside condition of the tubing worsen, cut every 500 ft until tubing wear and corrosion improves. If after 3000 ft the tubing’s inside condition does not improve, consider replacing the entire tubing string. For a more data-driven assessment method, the artificial lift specialist can review the historical failure locations for similar wells to recommend where to cut based on analog data.

Mechanical inspection and testing is recommended for tubing used in highly deviated areas or in places where there has been a high incidence of rod-on-tubing wear.

Because corrosion doesn’t happen to just one joint of tubing in a string, guidelines were developed for laying down the failed joint and other potentially affected joints of tubing, as follows:

- Lay down the failed joint and the joint above it and below it. If the failed joint has a split seam or a manufacturer’s defect, consider replacing only the failed joint.
- If there is a second seam split in the string, send the string in for inspection.
- If a seam split occurs within 2 years of new tubing installation, consider junking the entire string.
- To prepare for a RCFA review of a failed joint of tubing, split the joint lengthwise, clean up the failed side, and keep the other side with the original evidence. Samples for this should be minimum of 12” long.

Decisions about laying down the entire tubing string are best made with the collaboration of the Workover Completion Specialist (WOCS), Lift Specialist (LS), QA/QC, Rig Operator, and Reverse Unit Operator. The history of the well and downhole configuration (including if it is a problem well) should also be considered in this decision.

The criteria developed for laying down the entire string are as follows:

- If three bare joints burst when hydro-testing a tubing string,
- If the tubing string has been in the hole 5+ years without any holes, followed by two tubing failures within one year of each other, or
- If the tubing string is known to have heavy iron sulfide or scale deposits.

Tubing couplings for bare tubing should be made from 8600 series steel. The standard of acceptance for tubing couplings is when a made-up coupling has a 1-2 thread standoff.

Most areas use production tubing for routine work, but if there is a major workover, a work string is used. For safety purposes the Rig Operator, Reverse Unit Operator, or WOCS should provide an accurate number of trips the work string has made. This will eliminate near misses from parted tubing pins.

Run the better tubing on the bottom of the string, unless the expected tensile loading of the highest-stressed joint exceeds 80%. If the tensile loading might exceed 80%, then run the better tubing in the higher-stressed locations. The location of any tubing that is run with minor corrosion should be documented.

Internally Coated Tubing

The following are recommended uses of PCID tubing in producing wells:

- Run two or more joints of PCID tubing above the seating nipple in producers.
- Run PCID tubing in the top joint in a producing well.
- Replace all PCID tubing in producers each time the tubing is pulled and returned to production.

Fiberglass-lined tubing or PCID tubing should be run in all injection wells. Use seal lube for pipe dope on wells in CO_2 injection service.

When replacing internally coated tubing for injectors:

- Hydrotest fiberglass-lined tubing to 3500 psi and lay down any bad joints. Fiberglass lining companies suggest not exceeding 4000 psi during pressure tests.
- Hydrotest IPC tubing to 5000 psi or 80% of burst, whichever is less.
- Visually inspect PCID for chips in the coating at pins and replace any bad joints.
- Do not rerun cement-lined tubing.

METAL SUCKER RODS

Metal sucker rods operated within fatigue endurance limits do not wear out or age from cyclical loading. Metal rods can be either visually inspected onsite or sent in to be inspected. It is very difficult to inspect rods visually onsite, particularly with iron sulfide coating the rods. If the rods are send out for inspection, the rods must be palletized and handled using API procedures. A log of recovery rates should be kept, and the profitability of inspection should be evaluated regularly, including the additional rig time and the cost of palletizing.

Rods can be reused without inspection based on the multi disciplinary team's best judgment. The best decisions are made by collaboration of the WOCS, LS, QA/QS, RO, RUO and chemical representatives. Mill scale will not lead to a failure, so it should not be considered when inspecting rods on location. Rods are considered to have excessive corrosion and need to be replaced when the crew can see actual pitting. A pit is generally considered significant when it exceeds the size of a fine ballpoint pen or a 0.020" feeler gauge. When rods with small amounts of corrosion are rerun, the files should be updated with documentation thereof.

Rods are considered to have excessive wear and need replacement when:

- They have a shiny spot
- They have a flat spot
- The wear affects the rod shoulder

Rods are considered to have excessive stretch and need replacement when the longest triple within a taper hanging in the derrick is 6-8" longer than the shortest triple within the same taper in the derrick. Some manufacturer rod specifications allow rods to vary by ± 2", so a triple could vary by 12" and still be within the manufacturer's specifications. However, it is likely that rods produced at the same time will be similar in length.

When replacing a failed rod, also replace the rod above it and below it. When a rod string has two failures in one rod taper within one year, the taper should be replaced. When a rod taper has three failures in the same taper (regardless of time frame), the taper should be replaced.

ROD BOXES

The maximum number of properly torqued rod connections (make-and-breaks) is usually 8 or 9 before the coupling should be replaced. Rod pins, however, are assumed not to wear out. Making up rod connections with the circumferential displacement method (CDM) is a best practice. Clean the connections on the floor as they are run.

Rod boxes are manufactured with wide or thin faces. It is recommended that only wide-faced couplings be used, which will help give more consistent makeup.

Some may consider rods with squirting boxes to be damaged but not "failed." There are two types: T-couplings and spray metal (SM) boxes. It is a best practice to run T-couplings (except in highly corrosive applications), which can easily be changed out by the rig crew. All squirting T-couplings should be changed out, and if a rod string taper has three squirting T-couplings, all of the couplings in that taper should be changed out.

It is not necessary that squirting SM boxes be replaced in all applications. Because the SM is harder than the jaws of a pipe wrench, changing out the SM couplings is more difficult, costly, and may result in damaged rods. The best practice of running T-couplings will eventually phase out the use of SM couplings over time. Meanwhile, start documenting the location in the rod string of any SM squirting boxes, and whether they are replaced or not, during an intervention. This information will be used with pin/coupling failure data to estimate the economic impacts.

ROD GUIDES

Poly-ketone rod glides are recommended for long strings, and Martin Polymer rod guides are suitable for installation in EOR applications.

SINKER BARS

Sinker bars with lifting necks are recommended. If there is any pitting on the necks, the sinker bars should be replaced.

DOWNHOLE PUMPS

In most cases, the pump will be replaced with each intervention. However, it is ultimately the judgment of the engineer as to whether the pump should be replaced.

The following are some recommended repair guidelines for downhole pumps:

- Change the seats and balls after any rod parting failure.
- Change the valve rod or pull tube at every repair.
- Change the valve rod guide at every repair.
- Pull tubes should be made of heavy-wall brass nickel carbide or steel metallurgy.
- 4-ft grooved plungers should be used for pump depths less than 6000 ft.
- 6-ft grooved plungers should be used for pump depths greater than 6000 ft.
- Replace the plungers when damaged. Do not just flip them over and reuse them.
- Use a 24” perforated steel strainer nipple on pumps (minimum length).
- No tool marks should be visible on any pump components.
- Replace all 3-year-old parts.
- Have a full hole combination coupling 3/4” to 7/8” with every pump for 2 7/8” tubing.
- Use a new lift sub for every rod insert pump.
- Build a new pump if a barrel has to be replaced.
- All problem wells should get at least one new pump installation during its problem well tenure, preferably as soon as it becomes a problem well.

ADDITIONAL DOWNHOLE REPLACEMENT GUIDELINES

Use a stabilizer bar with a 7/8” pin on all steel rod strings in 2 7/8” tubing with rod insert pumps. Use a stabilizer bar with a 3/4” pin on all steel rod strings in 2 3/8” tubing with rod insert pumps.

Every time a well is returned to production, a pony rod exceeding the length of the surface stroke should be added above the sinker bars to change the wear pattern.

When called for on the lift design, use a 3/4'” or 7/8” back-off coupling (right-hand release) on all steel rod strings in 2 3/8” and 2 7/8” tubing, otherwise they should be left out of the design.

On fiberglass rod strings, use a 3/4” or 7/8” on/off tool or 26k shear tool, but upgrade to a 33k shear tool if it meets these criteria:

- 2” pump in depths greater than 5400 ft
- 1.75” pump in depths greater than 7100 ft
- 1.50” pump in depths greater than 9700 ft