SMALL DESIGN CHANGES CAN INCREASE WELL PRODUCTION AND REDUCE EQUIPMENT FAILURE

RODNEY SANDS
HARBISON-FISCHER DOVER ALS

ABSTRACT AND SCOPE

We explore how minor modifications in routine usage of typical rod pumping equipment may improve the performance of rod pumped wells; e.g. how initial proper selection and implementation of polished rods can limit well failures. Also discussed are pump design changes to mitigate common pumping problems, and why standardized pump designs are not over-all beneficial to producing wells. Additionally, we illustrate that standardized or "common" downhole design limits production rates.

RXB VERSUS RHB PUMP DESIGN

A RXB pump design enables you to run a 1-1/2" bore pump in 2-3/8" tubing. This is a more ridged design and is able to withstand higher pressure than the RWB design. Some operators are using the 20-150 RXB in 2-7/8" tubing also. This pump barrel is 1-7/8" and the ID of the 2-7/8" tubing is about 2-1/2". Operators typically choose to place a guide ring the top of the pump barrel in this design to center it in the tubing. This guide ring has been problematic in causing a hole in tubing where it is up against the tubing. In a well that runs 12 hours per day at 7 strokes per minute, the ring comes into contact with the tubing over 5000 times per day. Some of this has been mitigated by using non-metallic rings, but this does not completely eliminate it. To use this pump in 2-1/2", tubing you must use a connector from the smaller cage to the 2-1/2" hold-down seal assembly. The standing valve cage design on these pumps are the same as what is used in 2" tubing. One positive in this pump design is a reduction of spare pump inventory. If you have a mix of 2-3/8" and 2-7/8" tubing and need 1-1/2 heavy wall pump designs, you can use the RX design in both sizes.

A BETTER DESIGN

A 25-150 RHB design has benefits over the 25-150 RXB design. Starting at the top, this design has an extension with a 2.125 outside diameter typically 3 to 4 foot long. Compare that length to the guide ring that is less than 2 inches long. The extension eliminates the damage to the tubing by spreading the contact over a much larger area. This design allows the use of a larger valve rod or pull tube guide. If you are using a Two-stage Hollow Valve Rod, pump this design allows for a larger gas and sand check valve. Another advantage is the internal diameter of the extensions is larger than the barrel's internal diameter. This allows for a stroke through design that wipes the plunger at the top and bottom of the stroke. This has advantages in wells that scale builds up on the internal diameter above and below the plunger stroke. Compression style cages are available for the bottom of the pump to replace the lower extension for wells that have gas interference. The standing valve for the RH design pump is much larger than the standing valve for the RXB design pump.

STANDARD VALVE SELECTION

Valve fouling causes pump performance issues and premature pump failures. Typical clearance between the ball and the ball guides are about .030 inches. It is easy to see how particulates can get trapped between the ball and ball guide sticking the valve open or causing a delayed closing. When particulates become a propping agent and hold the ball off of the seat, it causes the seat to be fluid cut. Pressure above the valves is great enough to cut the sealing surface of the valve seat resulting in valve leaking and poor pump efficiency. A differential in pressure of 2000 pounds per square inch will produce a jet of fluid through a 1/32 inch orifice of over 500 feet per second. This is accelerated if the fluid carries particulates in suspension quickly damaging the sealing surface.

SOME BETTER DESIGNS

By adding an additional valve in tandem it is highly unlikely that both balls would be fouled at the same time. It can extend valve life and also reduce the delayed closing of the traveling valve and standing valve. Much has been said about gas issues and double valves. On a 1-1/2" bore pump, adding a secondary traveling valve only adds 2.561 inches^3 of unswept volume. Another option is to increase the clearance between the ball and the ball guides in the cage. One option is to simply convert to alternate pattern balls on your seats. Each seat size has two different ball sizes. One is the standard API size; the other is the alternate or “California” balls. For the common 1-3/4” seat size, the API ball is 1-1/8” and the alternate pattern ball is 1”. In most applications, using alternate pattern balls inproves performance with no negative effects. In severe gassy situations or very large bore pumps, you may “beat out” your cage with the increased clearance.When you increase the clearance between the ball and the ball guides, the ball is not centered as well in the cage. This can lead to single point impact on the seat rather than the “exagerated cushioning effect” that is desired. Two design changes can help with these issues. One is adding a fourth guide in the cage design. This fourth guide helps to center the ball on the seat and not have as much cage wear.The four guided cage design comes in several different clearances so they can be custom designed for your well. Insert guided cages can be used and are considered by many as the ultimate cage design to increase the cage and ball and seat life. These designs have a cobalt alloy insert that is put into a shell of various material. This insert is designed to protect the ball as well as the cage. Another benefit in this design is that the insert is replaceable. In wells with severe particulates, there is another design called a full flow design. This cage has a opening at the top much larger than a standard cage design. The full flow cage has been very successful in producing coal seam wells that have a high amount of particulates.

PLUNGER DESIGN

A standard pin end plunger is used in most pump designs without a lot of problems. However, these plungers can be problematic in wells that give up a lot of particulates. The plunger pin tapers down from the body of the plunger to allow the plunger coupling to thread onto the plunger. This taper is a place for particulates to get trapped and ride during the pumping cycle. The hydrostatic pressure along with the plunger running over the particulates force these hard particles into the barrel plunger interface. The particulates cut away at the protective spray metal coating exposing the bare metal below causing premature plunger failure or stuck plungers.

PROTECTIVE PLUNGER DESIGN

A standard pin end plunger can be protected by adding wipers above the plunger. This protects the leading edge of the plunger from damage. One of the best designs is one that balances the hydrostatic pressure above and below the wiper. This keeps the pressure from damaging the softer wipers during the pumping cycles. Other designs are available that have a sharp leading edge on the top of the plunger. This edge keeps particulates from getting between the plunger barrel interface. There is another entirely different pump design with a long plunger and short barrel. This pump uses a box end plunger rather than a pin end. Since the end of plunger never goes into the barrel, the particulates are wiped away from the barrel instead of being carried into it.

BOTTOM HOLD-DOWN PUMPS STICKING

Bottom hold-down pumps have an advantage over top hold-down designs because they equalize the hydrostatic pressure on the inside and the outside of the pump. The design flaw is that they sometimes get stuck in tubing because particulates accumilate above the hold-down in the barrel tubing interface.

DESIGN TO ELEMINATE PUMPS STICKING

One of the best ways to keep your pump from becoming stuck in tubing is to use a top hold-down designed pump. Sometimes the way you operate your well or the seating nipple depth does not allow for a top hold-down pump. Another good design used in shallower production is a travel barrel pump. These pumps are good in wells that have severe particulates. Surging fluid at the bottom of the barrel sets up a turbulence and keeps the pump from becoming stuck in tubing. Several different tools are available in a rubber or brush material to stop the particulates from entering the interface between the barrel and tubing. They are positioned right below the pump discharge stopping the solids from falling down the tubing. There is one design that expands a setable rubber seal out against the ID of the tubing. You seat your pump and set the weight of the rods on top of the pump. Then a rubber seal expands against the ID of the tubing. When you are ready to pull your pump you unseat the pump and wait 10 minutes as the rubber relaxes. Then you can pull the pump in the conventional manner. All of them are helpful to a varying degree based on their design.

POLISHED ROD COUPLING

A common mistake happens when you are connecting your sucker rod string to the polished rod. A sucker rod coupling is used rather than one that is designed for a polished rod pin thread. A coupling designed for a polished rod can be used on a sucker rod with no negative effects. API requires that all polished rod couplings and sub-couplings be designed for polished rod threads and marked with a PR along with the manufacturer’s name or mark.

Field personnel should be trained to look for this mark before installing a coupling on the polished rod. Because this marking is difficult to see, vendors have used several different methods to draw attention to the correct coupling they bring to location. Some of them are putting a piece of black tape or spraying white paint on the correct coupling. Even with much effort to keep the wrong coupling off of the polished rod, we continue to have failures.

A BETTER DESIGN

Design your polished rod pin with a different size thread than the top sucker rod pin in your rod string. All sub-couplings or combination couplings are required by API to have polished rod threads. Here is an example; if your sucker rod or pony rod that connects to the polished rod is 7/8", then use a 1" pin on your polished rod. In this case, the field personnel must use a sub-coupling to connect the polished rod and sucker rod string. This simple design change can lower these failures. Polished rod failures are sometimes not given as much attention as other well problems. Remember, you have lost production and possible corrosion damage due to loss of chemical film during the down time. A polished rod part at the top of the stroke can do a lot of damage, possibly causing a tubing part. If you have fiber glass rods, the entire taper may be ruined.

SPRAY METAL POLISHED RODS

There is another common error regarding a spray metal polished rod. The polished rod clamp is put on the spray metal portion of the polished rod rather than the unsprayed area. Polished rods are designed to carry very heavy loads, but are relatively soft. A hard spray metal coating is applied to these rods for abrasion and corrosion resistance. Because the material underneath the spray metal is softer, it will crack when you place your polished rod clamp on the sprayed section. This will cause the polished rod to part at the clamp.

A BETTER DESIGN

Purchase polished rods with a minimum of six to eight feet of unsprayed rod to place your polished rod clamp on. Space out your well with pony rods where you can place the polished rod clamp right in the center of the unsprayed area on the polished rod. As your well dynamics change, you will be able to move your clamp several feet either direction as needed. The price on the rods with more bare area is typically less than the ones with more spray. Some operators have learned that they typically have to raise their rod string after the well starts to pump down. In this case, you would want to clamp accordingly. With a little pre-planning, you can eliminate clamping on the spray metal portion of the polished rod. One additional safety idea is to use a polished rod with an elevator relief on the bare end of the polished rod. This eliminates the installation and removal of a pony rod on top of the polished rod during space out.

PUMP SPACING

Pump spacing is critical in two areas. You need to be sure that your pump supplier is spacing your traveling valve and standing valve as close together as possible. API requires the spacing be at least ¼" and no more than 2" off bottom. We recommend that the spacing be no more than ½" off bottom for pumps run into wells that have a tendency for gas interference. The next concern is spacing the pump in the well. Pump spacing allows for over travel of the sucker rod string. The amount of over travel changes with pumping speed and depth. Spacing a pump is more of a technique or expertise than a planned event. Predictive programs can give you a starting point or using 2" to 3" per thousand feet can accommodate over travel in most cases. For the best pump performance, the pump should be spaced as close to bottom as possible <u>without</u> tagging. Because of the changes in the fluid level, a well often needs to be respaced after it pumps down. If you are experiencing poor pump efficiency, it is likely it needs to be respaced.

DOWNHOLE GAS SEPARATION

Many times a wells bottom hole assembly is designed with a mud anchor the same size as the tubing string. The limited ID of this design leads to poor gas separation. Here is an example of a well that has a 2" bore insert pump and 100 inches of surface stroke. The 2-7/8" mud joint allows you to only stroke the pump 2.9 strokes per minute without pulling gas into your pump. At this speed the pump would produce about 135 barrels of fluid per day based on 100% efficiency.

A MUCH BETTER DESIGN

The very best design is to have set your pump below the lowest perforations and you will achieve a natural gas anchor. In horizontal completions and in wells with perforations near the bottom, this is not possible. Also, wells with high concentration of particulates may not allow you to pump below the perforations. In these cases, you should use the largest down hole separator that will fit into your casing. You would never use an undersized separator for your fluid on the surface. So, why would you do it down hole? There are many different style gas separators on the market today, but we will just discuss a collar sized separator in this paper. Compare the example above with a collar size separator. The increased size allows us to stroke the pump 8.5 strokes per minute rather than 2.9. That is a 262 barrel increase in a 24 hour period.

PROPER HANDLING

The very best design can be damaged by poor care and handling of your rod pump. When transporting your pumps, it is essential to protect them from damage by bending, denting, and dropping. They should be supported at a minimum of 8 foot increments. They should always be secured with non-metallic straps, never chains. The openings of the pumps should be covered until the pump is ready to run into the well. The pump should be placed in a safe location off of the ground until it is ready to run. Pumps should be picked up with a lifting device placed on the fishing neck of the pump. Picking up the pump by its valve rod or pull tube is a common mistake. This can bend the rod or tube causing breakage or wear on the ID of your tubing. Your pump supplier should be notified when you are pulling a well for a suspected pump failure. In most cases, your pump is steam cleaned on arrival to the pump shop. They will not do this process if they know there is a suspected pump failure. This allows them to look for the cause of your pump failure prior to washing away the evidence. A visit to your pump shop while your pumps are being repaired gives both companies the opportunity to understand each companies challenges. This helps in getting the pump designs needed and much longer pump life in your well.

CONCLUSION

Paying attention to how your equipment is serviced, designed, and handled is an important part of day to day business. A few small changes in your pump design, end of tubing design, polished rod practices, and pump spacing can improve your failure frequency moving to the next level.

REFERENCES

1. Harbison-Fischer Training Manual—13th edition June 2003
2. Penn State Technical Rod Pump Short Course February 2009
3. Harbison-Fischer Dover ALS Pump School 2015
4. Harbison-Fischer Dover ALS Gas Anchor Calculator
5. Harbison-Fischer Dover ALS Unswept Volume Calculator