Design and Selection of Sucker Rod Pumps for Troublesome Wells

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Armco Fluid Packed Pump

INTRODUCTION

Since the discovery of oil, the sucker rod pump has been the most accepted means of artificially lifting fluid from the well bore. With increasing demands for higher volumes from greater depths and high gas-oil ratios, the need for closely engineered pumping installations is inevitable if we are to expect maximum performance and maintain an economical operation.

Many papers have been written on down-hole gas separation and metallurgy to help increase pump performance and pump life. However, with increasing numbers of slim-hole and multiple completions, this becomes impossible. It is the intent of this paper to discuss some techniques and experiences to increase pump performance and minimize operational problems with the complete pumping installation.

PUMPING GASEOUS FLUIDS

The ultimate in pumping high gas-oil ratio wells would be to have single completions with large casing. Unfortunately, the past few years we have reverted to slim-hole tubingless and multiple completions which necessitate having to pump from beneath a packer. Consequently, all the fluid and gas entering the well bore must be produced through the pump.

Before designing the pump it is imperative that we know the bottom-hole pressure and the gas-oil ratio in the well as these two factors are directly responsible for the down-hole pump efficiency. We can then determine the volumetric capacity needed in the pump to get a given amount of oil in the tank. There are two ways to design a pump to achieve this; use a small bore and long stroke or larger bore and short stroke. Sometimes, existing surface equipment helps determine which way to go but the best way to handle gas would be the long stroke and smaller bore. This would give higher compression in the pump chamber than the short stroke and minimizes the chance for a gas lock. For example, a 1-1/4 in. pump at thirteen 64-in. strokes per minute would have a displacement capacity of 151 BPD and a 1-1/2 in. pump at thirteen 44-in. strokes per minute would have a displacement capacity of 150 BPD.

Another important feature of the pump for handling gas is the valve cage selection. There are many types and designs of cages; select one that controls the ball so as to eliminate spin and chatter. By doing this the ball is allowed to close faster at stroke reversal, giving the pump a longer effective plunger stroke, thus building higher compression in the pump chamber and again minimizing the chance for gas lock. For example, at ten 72-in. strokes per minute the plunger is accelerating an average of 24 in. per second. A one-second time lapse of the ball closing would result in a loss of 24 in. of plunger stroke. This stroke loss would also cut the volumetric capacity by 30 per cent.

The two-stage pump is a specially designed pump recommended for handling gaseous fluids. This pump has primary and secondary chambers with approximately a two-to-one compression ratio. The primary chamber is the area between the standing valve and the traveling valve on the bottom of the plunger. The secondary chamber is the area between the top of the plunger and the pack-off which seals on a hollow polished rod. This rod has a ball and seat on the top of it and is referred to as a traveling standing valve. The primary chamber has approximately two times the area of the annular secondary chamber.

On the upstroke of the pump, bottom-hole pressure is taken in through the standing valve to load the primary chamber. On the downstroke this fluid and gas is compressed into the smaller secondary chamber. On the subsequent upstroke the substance in this chamber again is compressed and discharged through the top ball and seat, or traveling standing valve, into the production tubing.

To obtain maximum performance from this pump it should be designed to fit the surface unit stroke. Maximum compression can be obtained only by spacing this pump close to top and bottom.

PUMPING HIGH VOLUME WELLS

Through the increased efforts of oil producers to maintain or increase their oil production, waterflooding has become necessary. This has brought about a need for higher volumes of fluid which places larger demands on pumping equipment.

In waterflood producing wells you generally can expect high water-cut fluids containing salt and hydrogen sulfide corrosion. This creates iron sulfide and iron oxide particles which are very abrasive and cause extensive wear on all moving parts of the pump. By the use of chemicals, corrosion resistant materials, heat treating and hard plating, this problem can be minimized to a large degree.

One of the more common failures in high-volume wells is pull rod and sucker rod breakage.

Body breaks in sucker rod are due to fatigue and overload. Even though the rod string is designed to carry a given load, shock loading can be imposed on the rods by improper valve action. The sucker rod string is slowed down at the top and bottom of each stroke due to the angle of travel of the crank to the beam. If the valves do not close right at or close to stroke reversal, the rod string has gained momentum by the time the valve closes. This imposes a hydrostatic shock load on the rod string and overloads the string causing failures. This problem can be minimized by selecting positive ball control cages which prevent ball spin and guide it directly back on seat at the end of the stroke. As stated previously, ten 72-in. strokes per minute would have an acceleration rate of 24 in. per second. One second, or 24 in. travel before the valves closed, would have allowed the rod string to gain its momentum and shock load the rod string.

Another cause of pump valve rod and sucker rod failures is stacking the rods on the downstroke. This happens most commonly when pumping solid fluid at high rates of speed. Anything over 24 in. per second, when pumping high water-cut fluid, will begin to stack the rods, or put them in compression. The compression, or pressure drop across the plunger on the downstroke is caused by the differential in area of the inside diameter of the plunger to the outside diameter of same. For example, the inside diameter of a 1-1/2 in. API composite plunger is 5/8 of an inch. This is a 5.75 to 1 area ratio. This increases the load range and creates a snap action on the rod string at stroke reversal causing rod failure and costly service jobs.

To counteract the pressure drop we must find some place for this fluid to go. This can be accomplished with the use of a bottom discharge valve. The bottom discharge valve contains the standing valve ball and seat as well as the discharge ball and seat. With this accessory, fluid is discharged out the bottom of the pump as well as up through the plunger. By minimizing the pressure drop across the plunger, the plunger is allowed to fall freely, eliminating the snap on the rod string on stroke reversal. In field tests, this has been very effective and has eliminated a large percentage of pull rod and sucker rod failures.

SUMMARY

These designs and techniques are results of actual field tests and experiences. They will help reduce down time and service costs which lower lifting costs and insure a more economical operation.