PRODUCTION WITH ESP'S IN GASSY WELLS

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One of the questions often asked of the ESP manufactures is "What is the maximum GOR your pump can handle?" As stated this question is impossible to answer. One of the limitations of centrifugal pumps is their inability to handle significant quantities of gas. However because of the configuration of the pump and the nature of its application, the question of its limits is extremely complex. This paper examines how the presence of free gas affects the operation of the ESP's and looks at some of the techniques used in selection of pumps for gassy wells

Pump Burden

Figure 1 shows an idealized inflow performance representation (IPR) of the pump requirements. The "burden of the pump" or required pump pressure is represented by the difference between the well inflow performance curve and the tubing outflow performance at the desired flow rate . This representation is idyllic because it assumes that the pump is handling only liquid and there is negligible volume change as the pressure is increased. In a real well the pump may be required to operate with significant quantities of gas.

Figure 2 shows an IPR with additional curves showing the total volume of liquid and gas and the volume through the pump assuming that the pump handles all the fluid. The burden of the pump may be the same pressure differential however the intake volume is increased by the free gas. The pump must be able to ingest the gas and compress it and pass it along. The volume that each stage will see declines as the gas is compressed and goes into solution.

The analysis is complicated by two problems: first the impeller flow characteristics may be unstable with gas, and second, calculations of free gas are based on the assumption that the gas and liquid are in equilibrium. Evidence indicates that they may not, it is possible for the fluid to leave the pump as a high pressure gas in an undersaturated liquid.

The Centrifugal Pump

The centrifugal pump is a dynamic device that uses the velocity of the fluid to produce the energy to lift a column of fluid. The equations that govern the device relates the produced head to the flow, geometry, and rotational speed. The density of the fluid does not effect the head produced. This means that a centrifugal pump will produce the same head regardless of the density of the fluid. A impeller that can lift a column of water 6,000 feet will also lift 6,000 feet of air at the same flow rate. The difference is that the required pressure for water is 2,600 psi verses 3 psi for air. The ESP is an inefficient compressor and should never purposely be selected for this.

Multi Phase Mixtures

The produced fluid from an oil well usually has more than one phase. It is most common to have three phases, water, oil and gas, flowing together. It is conceivable to have four phases, if you are willing to count sand, silt, or rocks as an integral part of the flow.

If the different phases can be evenly dispersed in one another, the pump may be able to handle the fluid. In a centrifugal pump, multi phase fluid may not be able to remain homogeneous. Due to the difference in density, the centrifugal force segregates the phases more quickly than the turbulence can mix them back in. The oil may have a density of .70% of the water, the solids (sand) may be 2 to 3 times the density of the water. Water and natural gas however can have a density difference of three orders of magnitude.

The size of the particle is also an important factor in maintaining homogeneous mixture. The drag force encourages particles to move with the fluid, and the buoyant force encourages segregation. The drag is a function of the cross sectional area of the particle and the buoyant force is a function of the volume. As the size of the particle decreases, it is more likely to flow with the fluid than to separate. A very finely dispersed phase can be difficult to separate and in the case of water oil emulsions, the fluid can develop some unusual bulk properties.

GAS GOR & GLR

Crude oil is not a pure substance. It is a mixture of a variety of elements and short, medium and long chain hydrocarbons. The API gravity of an oil reflects a bulk average of the densities of the constituents. Under sufficient pressure, all of these exist together as a liquid. If the pressure is decreased to the bubble point, these atoms and molecules start to liberate themselves and form the gas phase. The lighter gasses come off first. As pressure is lowered, the gas phase expands and the liquid phase shrinks.

When atmospheric pressure is reached, the volume of liquid can be compared to the volume of gas to calculate the gas-oil ratio (GOR). The GOR is expressed in standard cubic feet per barrel of oil, or in dimensionless terms (Direct Ratio), barrel per barrel, cubic meter per cubic meter. Because the produced fluid contains a significant quantity of water, it is more meaningful to compare the gas to the total volume of liquid for the gas-liquid ratio (GLR).

The ability of an ESP to function with gas can not be determined from the GLR alone. Due to the pump inlet pressure, the ratio of gas to liquid at the pump intake is not the GLR. Part of the gas is compressed and the rest is in solution in the oil. The percentage of free gas at any pressure is a straight forward calculation presented in many texts and tutorials (2,6).

To avoid confusion, when referring to the fluid at well flowing pressure, it has been suggested that the term "Vapor Liquid Ratio" (VLR) be used instead of GLR(2). Another way to look at the amount of gas is "void fractions". This ratios the volume of gas to the total volume under consideration. The void fraction, expressed in percent, can be referred to as the Free Gas Percent (FG%). Vapor Liquid Ratio and Free Gas Percent are related as follows:

$$FG\% = VLR / (VLR+1) \times 100, \quad \text{or} \quad VLR = FG\% / (100 - FG\%)$$

The goal of artificial lift is usually to maximize the production of oil from a well. This is accomplished by drawing the well pressure down as far as practical. The IPR in Figure 2 is an example well with reservoir pressure and bubble point of 1950 psi. The water cut is 86% and the GLR is 20 SCF/CF. If the well were producing 206 BOPD, the total volume of fluid would be 2000 BPD. If the total volume of fluid could be increased to 4000 BPD the oil production would only increase to 213 BPD. It is sufficient to say that as a well is drawn down, the volume of gas can become substantial.

Gas and the Centrifugal Pump

Gas affects the performance of centrifugal pumps in a variety of ways.

1. The gas increases the total volume of fluid.

2. The gas decreases the bulk density of the fluid.

3. The gas causes flow anomalies in the impeller.

In the example well, if the pump must handle all the fluid and attempts to produce 1,000 BPD of liquid, it must also ingest 250 BPD of gas, the total volume at the first impeller is 1,250 BPD (Fig 3). If this were the only way that gas affected the pump, the head production of that impeller would drop from 27 feet to 19 feet.

The gas cut fluid is less dense. If the liquid in this example has a specific gravity of 1.0, the gas would decrease the specific gravity to 0.8. The pressure developed by the first stage in this example drops from 11.7 psi for 27 feet of head to 6.6 psi, for 19 feet of head at a specific gravity of 0.8.

Many studies have been made to determine how gas affects the flow in an impeller. One study, Murakami & Minemura, 1974 (3), examined the effects of two phase flow using air and water as test fluids. The two phases seemed to act as two separate fluids, with the air lagging behind the water as it progressed through the impeller. At void fractions greater than 6%, air bubbles started to accumulate in the eye of the impeller blocking the flow and causing fluctuations. The fluctuations or surges occurred at a frequency of about one every ten seconds. A sharp decrease in the head was noted at void fractions above 4%. Some of their observations were confirmed in the paper by Lea and Bearden (4). The doctoral dissertation "Two-Phase Flow through Electrical Submersible Pumps", Sachdeva, 1988 (5), presents a summary of the literature and develops a model to predict the behavior of pumps. The model was able to predict the onset of surging as seen in the other studies.

Two papers have been published that are specific to observations of ESPs (2,6). The both attempt to predict when an ESP will give satisfactory performance, considering the amount of gas present in the liquid and the pump intake pressure.

The paper by Turpin (6) attempts to relate the pump performance to the vapor liquid ratio (VLR) and absolute pressure at the pump intake (Pa) by calculating a performance factor o :

$$o = 2000/3 \times (VLR)/Pa$$

According to Turpin, the pump can give adequate performance if the value of o is less than or equal to 1. If we set o equal to one, we can solve for the maximum amount of gas that the pump could handle. For 10% free gas (.11 VLR), the required intake pressure for an ESP to perform calculates to be 75 psi. This has a fair correspondence to the old rule of thumb (ROT) that an installed ESP with 100 to 200 feet of fluid over the intake could tolerate 10% free gas.

Dunbar (2) presents a graph of the vapor liquid ratio verses the intake pressure. A line divides the graph into an area that is suitable for pumping, and one that is not (Fig. 4). The line represents data from many years of operating experience. The author warns that the distinction is not sharp and that the line should be a broad band.

Comparing of the two papers (Fig 4), both show the same trend with Turpin being the less conservative. Care should be taken in using these, as both are based on empirical data, and neither claim to be exact. By lowering the value of o, the Turpin formula allows the user to adjust to fit the experience in a particular area. Both authors state that for the predictions to be valid, the pump must be sized for the total volume of liquid and gas at the intake.

Gas Interference in ESPs

The first indication that a pump is having gas problems is the gassy amp chart (Fig. 5). The cyclic rising and falling of the amps indicates that gas is somehow interfering with the production of the liquid. The example amp chart shows 13 to 19 peaks per hour. This indicates that the surges occur at a rate of one every three to four minutes. This is more than an order of magnitude slower than the rate observed by Murakami and Minemura. It suggests that the surges may have an origin other than impeller fluctuations.

The Surging Cycle

In order to enter the impeller of an ESP, the gas has to be pulled in by the drag forces in the liquid. The buoyant forces are at the same time attempting to pull the gas up the annulus. The intake velocity becomes significant in determining the percent of free gas that enters the impeller. The gassy amp chart could be explained by a slow cyclic surging shown in Figure 6.

Gas decreases the bulk density of the fluid.
Pump power and motor amps decrease directly with the density.
Decreased density causes a decrease output pressure.

There is a time lag between the change in the density of the fluid in the tubing above the pump and that of the fluid in the pump.

Reduced output pressure reduces the flow
Reduced flow rate means reduced inlet velocity.
Decreased inlet velocity reduces the gas that the fluid drags in.
Decreased gas increases the bulk density of the fluid

The cycle is ready to swing back the other way.

Increased fluid density increases:
- the required pump power,
- the motor amps,
- the pump pressure,
- the flow
- the intake velocity
- the amount of gas in the pump.

This cycle may be stable and continue indefinitely, or eventually dampen out. It can also become unstable and gas lock the pump.

Gas Locking

Gas locking is a phenomena that occurs in centrifugal pumps when the decrease in performance and flow restriction caused by the gas in the impeller eye becomes so severe that flow stops. When this occurs, the fluid centrifugally separates in the impeller and the pump is locked.

In order to "unlock" a gas locked impeller, there must be enough pressure to force the gas bubble out of the eye of the impeller. In a system where the pump output pressure is governed by the flow, the pressure drops to zero when the flow stops. The impeller will automatically unlock. In an ESP, the largest component of the head is the vertical lift. The tubing friction loss is seldom more than 10%. The flow can drop to zero, with less than a 10% change in the required head.

The ESP can only be unlocked by a significant increase in intake pressure or stopping the pump. The intake pressure must be increased enough to push the gas out of the first impeller which must in turn push the gas from the second impeller and so on. The pressure required to do this is additive.

The well may not be able to increase the pressure enough to unlock the pump, or inadequate cooling flow may cause the motor to burn first. Cases have been reported where fluid was flowing out the annulus, but the pump was still running and gas locked.

The pump can be unlocked by shutting it down. If the system does not have a check valve, the fluid in the tubing drops back through the pump and forces the gas out. If a system has a check valve, the gas percolates up through the impellers and diffusers and collects in the tubing below the check valve.

Operational Design

Short of altering the pump or adding other devices, it is possible to increase the capability of the ESP in a gassy well. Increased pressure at the pump intake has several beneficial effects. It decreases the percent of free gas at the pump intake, decreases the size of the bubble, and increases the density of the gas.

This can be done effectively by lowering the pump. As far as the performance with gas is concerned, the lower a pump is set, the better it will operate. Without a motor shroud, the lowest that the unit can be set is slightly above the perforations.

If the casing size will accommodate a motor shroud,the pump can be lowered further. A pump in a shroud below the perforations takes advantage of the natural annular separation at the perforations and increased intake pressure.

A pump can be set above the perforations with a shroud and stinger. The stinger is a section of tubing that is connected by a reducer bushing to the bottom of the shroud. This allows the ESP to take suction below the perforations, without being set below them. This system takes advantage of the natural annular separation, however the pump intake pressure is decreased by the tubing friction and will be lower than the system without the stinger.

Some care must be taken using either of these systems. There must be enough clean rathole below the shroud or stinger to keep from jamming it into the trash and sediment in the bottom of the well.

Equipment Design

It is possible to increase the capability of the pump in gas by manipulating the number of stages or the volume rate of the stages.

Overstaged Pump

Overstaging the pump is based on the idea that, since the bulk density of the fluid is going to be less, it will be necessary to have more stages to provide the same amount of lift. The rule of thumb is to add one percent more stages for every percent of free gas at the pump intake above ten percent. This seems to be based on the assumption that the annular separation at the pump intake may take care of the first ten percent of the gas, and the overstaging will take care of the rest. Overstaging has shown positive results for relatively mild gas conditions of less than twenty percent.

Tapered Pump

In a tapered pump, the volume size of the pump stage is reduced as the fluid progresses up the pump. Starting with a stage large enough to handle the total volume at the intake the volume size of the stage is reduced in steps to approximate the change in the fluid volume. In a design procedure (7), the pump differential pressure is divided into increments. The properties of the fluid are calculated for the intake conditions. A pump volume size is selected that will handle the total fluid at the inlet conditions, and the number of stages required to generate the pressure for the increment is calculated. The process is repeated at the inlet to each increment until all of the gas has gone into solution, or the required tubing inlet pressure is reached.

Both of these methods can increase the gas handling capability of an ESP, however neither attempt to address the performance degradation from gas interference. The overstaged design is simple and uses standard "off the shelf" equipment. The tapered pump should be able to handle a greater volume of gas, but the design is specific to the well and has to be specially built. The tapered pump may also encounter up thrust and down thrust problems if predictions about the fluid are in error. Both of these methods could be improved by correction factors for decreased impeller performance. In either case the motor should be sized for the all-liquid condition to keep from being overloaded when unloading kill fluid or if the water cut increases cut later in the life of the well.

A modification to the tapered pump is the oversized lower tandem. This pump approximates a tapered pump by using full housing lengths of a large volume stage for the lower pump in a tandem arrangement. Rather than having the pump sizes change gradually, as the fluid compresses, this pump makes one large change. With the significant difference in the volume size of the lower and upper tandem, thrust problems are almost guaranteed. This type of unit can give good service, if the thrust problems are solved. The full fixed impeller or modularly fixed type of sand pumps have shown promise.

Separators, Mixers, Handlers and Breakers

This section covers devices that can be added to the equipment string and may improve the performance. The individual capabilities of these devices are beyond the scope of this paper.

Static Gas Separator

The static or reverse flow gas separator attempts to take advantage of the buoyancy of the gas by forcing the fluid to make a downward turn in order to enter the pump. A variety of arrangements of cups, holes, helixes, and slots have been used, mimicking many of the gas anchors used with rod pumps (8).

Dynamic Gas Separator

The dynamic or rotary gas separator uses the rotating shaft to spin the fluid so that the centrifugal force will cause the gas to separate. There are several types, distinguished by the way they handle the spinning fluid. These units have proven to be very effective for handling quantities of gas

Gas Handler

A gas handler is similar to a static gas separator in that it forces the fluid to turn and enter the unit in a downward direction. In a gas handler, the downward moving fluid is directed into the eye of an upside down impeller. In theory the impeller can not remain gas locked because there is always a column of liquid ready to enter the eye. It is suggested that the upside down impeller will be able to "charge" the first impeller, increasing its pressure and reducing the tendency to gas lock.

Gas Mixer

The smaller the gas bubbles and the more homogeneous the fluids, the better the impeller can handle them. The gas mixer is just what it says it is. The device attempts to break up the gas into small bubbles and homogenize the fluid. It may cause some problems if the fluids tend to emulsify.

Slug Breaker

Slug breakers occasionally have been employed in wells where it is suspected that the gas is slugging rather than being entrained in the fluid as dispersed bubbles. The slug breaker looks very similar to the dip tube in a rod pump gas anchor. It functions by having the pump take suction from the bottom of a fluid reservoir. The fluid enters from the well bore at the top of the reservoir. The pump can maintain its prime as large gas slugs belch by.

Effect on Run Life

It must be pointed out that there has been some concern on the effect of these gas devices on the run life of the equipment. These devices are interposed between the pump and the seal section. The unbalanced thrust that is developed by the pump is absorbed by the thrust bearing in the seal section. This thrust, acting across the short shaft in gas device tends to cause it to buckle (Figure 9). This buckling tendency can cause large side loads on the radial bearings, reducing the life of the equipment. No extra equipment should be added to the ESP unless it is really necessary.

Conclusions

In artificial lift the goal is to maximize production. The efforts are therefore directed towards pulling the fluid level down as far as possible. The limit in many wells using ESP, is the ability to handle gas. If the gas capability is increased then the well will be pulled down further, until the pump again starts having gas problems. The gassy amp chart reflects a slow cyclic change in the motor load. Other than the difficulty in setting the motor underloads, this cyclic loading does little or no harm to the ESP.

Figure 8 shows the incremental increase in gas for the example well used in Figure 2. The volume of gas is given as both the vapor liquid ratio and as the percent of free gas. As the flow approaches maximum the gas increases radically. Figure 9 is a blow up of the lower right hand corner of Figure 8. The shaded area represents the limits proposed by Dunbar and Turpin. Dunbar's suggestion is the lower limit and Turpin's is the upper. This empirical work suggest that this well can produce 85% to 90% of its maximum without specialized equipment. By adding a rotary gas separator it may be possible to pick up another 5%. Increasing the production beyond this would be exceedingly difficult.

Exact analysis of the gas problems in an ESP is difficult. It is not known if the gas goes back into solution when the bubble point is reached, or passes into the tubing in a non-equilibrium state. Some techniques and devices reviewed can be used in combination. Every additional piece of hardware increases the cost and the potential for failure. Is it worth the extra equipment, and headaches to get one or two percent more oil? Each well must be analyzed separately to identify it's point of depreciating returns.

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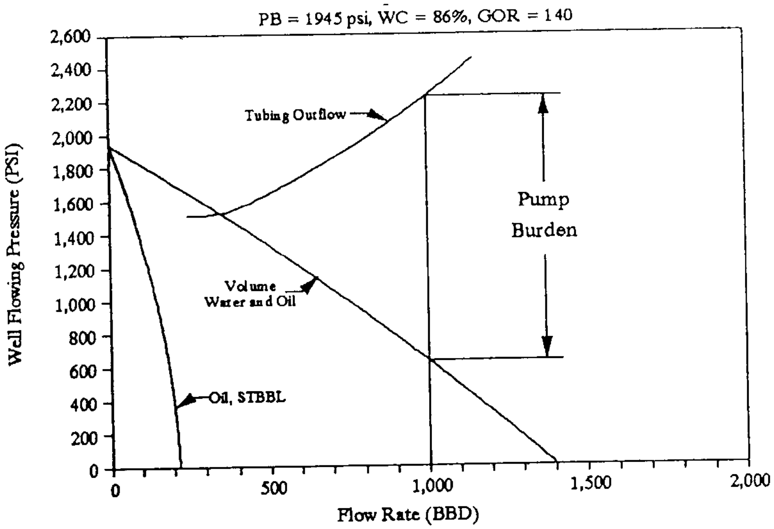

Figure 1 - Example IPR

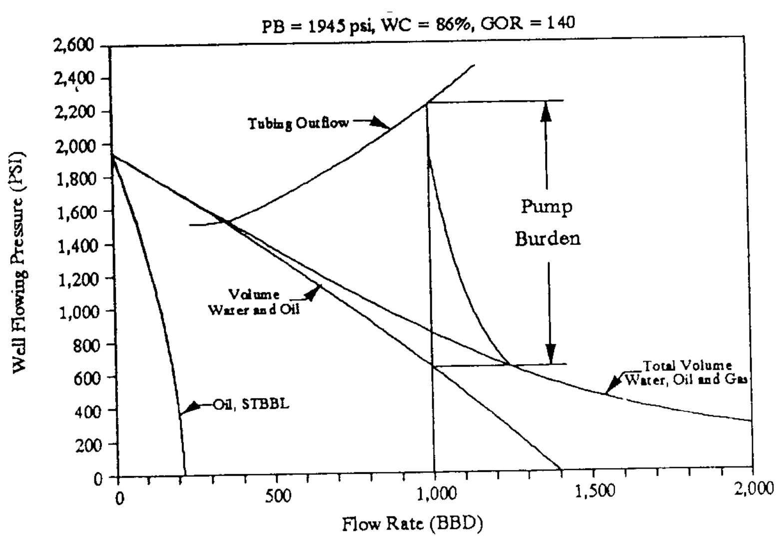

Figure 2 - Example IPR

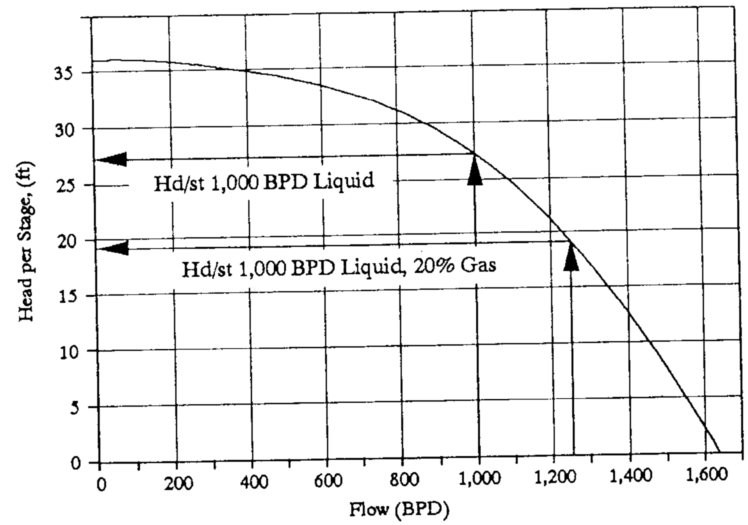

Figure 3 - Performance curve, BPD pump

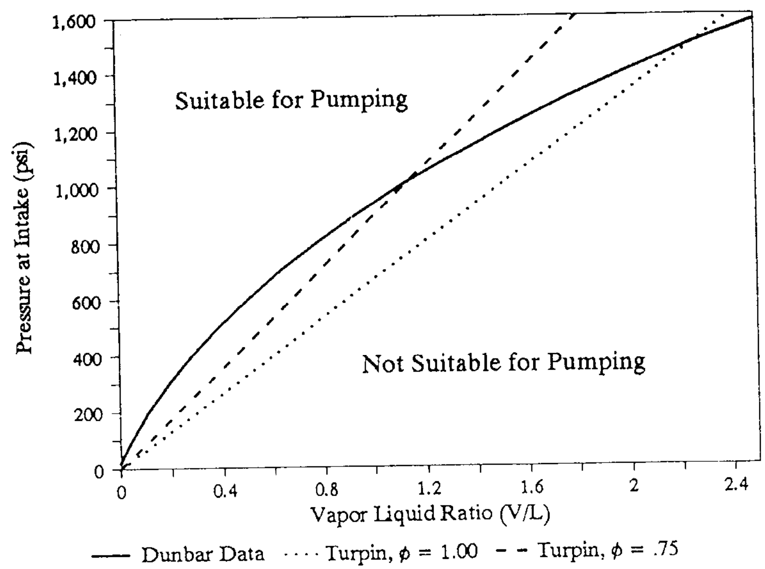

Figure 4 - ESP suitability in gassy wells

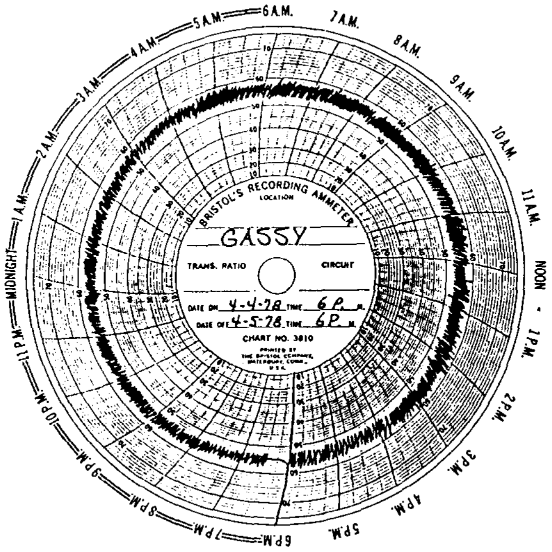

Figure 5 - Gassy amp chart

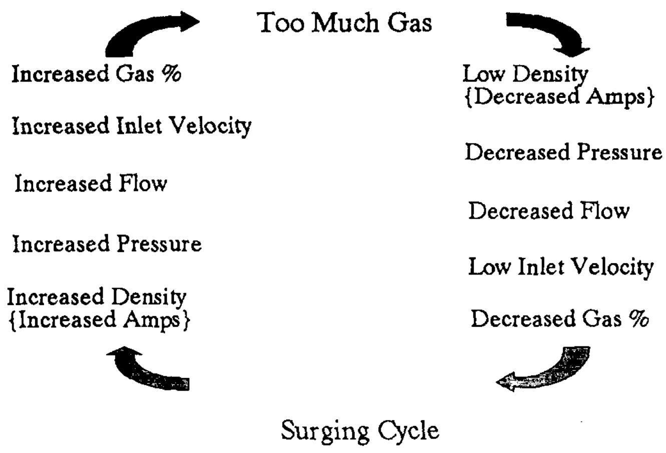

Figure 6 - Surging cycle

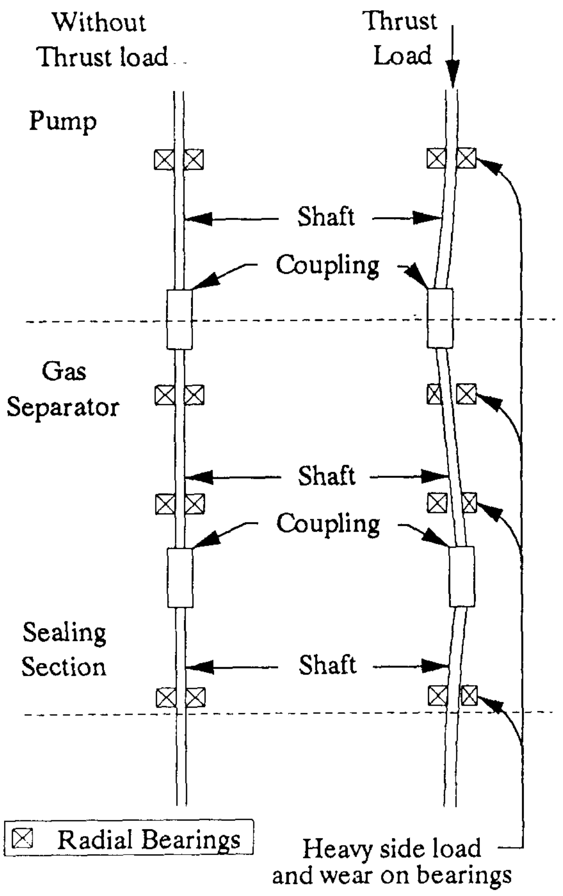

Figure 7 - Shaft buckling

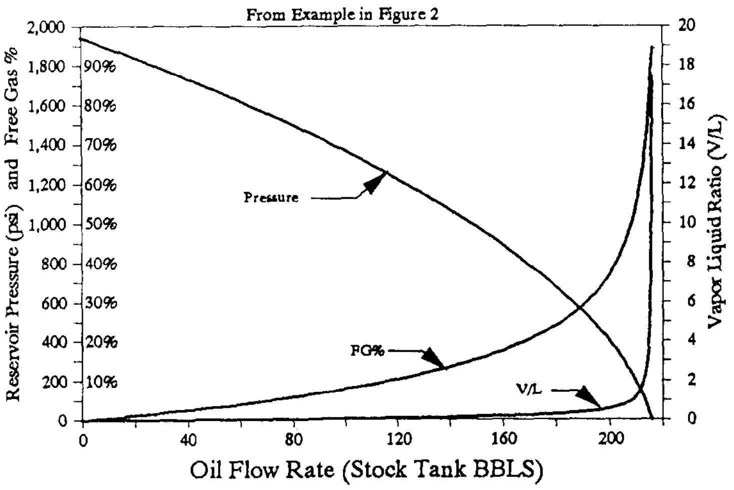

Figure 8 - Oil production vs. gas production

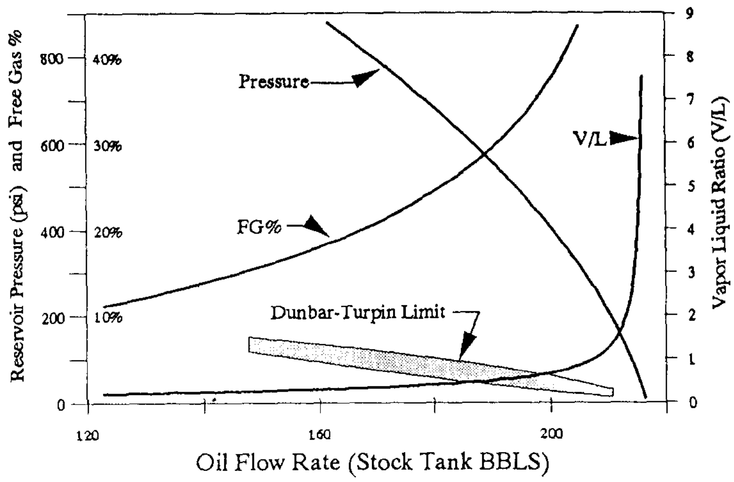

Figure 9 - Oil production vs. gas production