ARTIFICIAL LIFT
PRODUCING AT HIGH RATES

BY

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INTRODUCTION

Any fifty-minute discussion of artificial lift can be only an overview. It is impossible to cover the four major types -- rod pumping, electrical submersible pumping, hydraulic pumping and gas lift -- comprehensively in such a time frame. Nonetheless, I hope to give you a little better understanding of what the major considerations should be when selecting, designing, installing, operating, or repairing high rate artificial lift systems. For those who desire more information, I have prepared a bibliography of what I consider are the best published artificial lift papers.

All of my 32 years experience has been in the USA with Shell. What I recommend on artificial lift is what is followed in many fields. Naturally some locations do a better job than others. We think we have good reasons for doing what we do but we have made some mistakes. Our thinking changes as technology and equipment improves and we gain experience.

Before I start discussing artificial lift projects, I would like to make a few points on economics. Most of us are interested in making the highest present value profit after tax (PVPAT) for the entire life of the project. There are always special conditions that must be considered which alter the economics. Such things as location, lift depth, casing size, etc. have a large effect on the profit picture. Thus, one has to get his priorities in the right order for the particular case. What is important in an offshore field can be significantly different from a dry land location. Shallow lift has different problems from deep lift. Proration has drastic effects on the operation and the PVPAT.

The long range goal of making the highest PVPAT is more important than short term goals. Eliminating preventive maintenance in artificial lift will result in a loss in PVPAT. Overloading or abusing equipment for long periods should also be avoided. With these things in mind, let us proceed to discuss artificial lift in general.

OIL AND GAS WELLS STATISTICS

Many of you are generally familiar with the production in the USA. For the past few years the USA has produced about 8.5 million barrels of oil per day. The number of oil wells on artificial lift has gradually moved up to 570 thousand wells in 1983. In addition there are about 33 thousand flowing oil wells. Thus if you divide the daily production by the total number of oil wells, it turns out that the average oil well in the USA makes about 14 barrels of oil per day. In addition, the USA has about 214 thousand gas wells of which a few are on artificial lift.

The numbers are somewhat different for Shell. We operate about 18.5 thousand oil wells of which almost 17 thousand are on artificial lift. Our average oil well makes about 32 BOPD. In addition we operate about 1500 gas wells and over 5000 service wells.

The above statistics do not tell the full story. The average oil well in the USA makes over 10 barrels of water for each barrel of oil produced. This is also true in most Shell fields. We are a mature producing country with a lot of water drive fields where the producing water cuts have skyrocketed. Also the USA has many depletion and solution drive fields that are under water flood that are experiencing water break-through. In addition the wells are getting deeper. Thus, we must now lift higher rates from greater depths. Operating costs are rising -- especially power costs. Furthermore the industry is also using steam and carbon dioxide in many fields for enhanced recovery which causes some interesting artificial lift problems. Thus, it has become very important for us to do a better job in artificially lifting our wells.

TYPE LIFT DISTRIBUTION

Rod pumping is the dominant type of artificial lift in the USA -- comprising about 86 percent. For instance, those who have driven through oil fields in the USA should have observed the widespread use of the beam pumping unit. In a distant second place is gas lift, which accounts for about 10 percent of the wells on artificial lift; electrical submersible pump (ESP) and hydraulic account for the remaining 4 percent.

But, again, this is not the full story. If one eliminates the stripper wells (441,500 wells that on an average make less than 3 barrels of oil per day), then gas lift and beam installations in recent times are about equal. However, if one talks about high rate lift for land operations nowadays, most people think about ESP. In 1983 there were as many ESPS installed as gas lifted wells. ESP is on its way up - especially for high rate lift.

As I said before, we operate about 17,000 oil wells that require artificial lift. Rod pumping accounts for about 13 thousand wells (83.2%). All of these are on land and produce on an average 24 BOPD and 123 BWPD. We operate about 2200 gas lift wells (12.8%) -- mostly offshore in the Gulf of Mexico which produce an average of 40 BOPD and 360 BWPD. Some 583 oil wells are on ESP (3.6%) and average 77 BOPD and 984 BWPD. Only 61 wells are now on hydraulic lift (0.4%); they produce an average of 49 BOPD and 333 BWPD.

Rod pumping is the standard lift method for land locations. If there is not some unusual problem and if the well can be pumped down with rod equipment, that's what will be installed. If rod pumping is inadequate to pump the well off or there is some environmental problem, then our next choice for land locations would be ESP. Hydraulic pumping is rarely recommended and then only by default.

For offshore Gulf of Mexico operations, the standard lift method is gas lift. There are a number of good reasons for this choice: gas is available, sand production is characteristically present, wells are usually deviated, wire line retrievable valves are used, compression is needed for gas sales, and so forth. On the other hand for offshore California (Beta Platform), ESP's were installed. Why? Because at that location there is not enough available gas, the crude has a high viscosity, and a high draw down is required.

PRODUCING CONDITIONS

Let us spend a few minutes discussing the producing conditions for any type of artificial lift installation. It is important to know what is limiting or restricting the production when you desire to produce at maximum rates. The type of limitations on producing conditions can be divided into three categories: 1. Well inflow restriction, 2. Well outflow restriction, or 3. Surface (Non-well) restriction.

Inflow Restriction

Many artificial lift installations are designed to obtain as much production as the reservoir will give up; i.e. producing at the reservoir inflow capacity. To do this the well must be produced at a low bottom hole producing pressure. Thus the well is considered pumped off. In practice it is not feasible to reduce the bottom hole pressure to zero and usually not profitable. It has been found that operating with higher pump efficiencies is often more profitable than pumping the well off. Pumping a well off usually means over-pumping the well and abusing the equipment -- which significantly increases costs without much additional income. Keep the wells pumped down without over-pumping them!

High volume continuous gas lift wells are seldom producing at the inflow capacity due to the high back pressure imposed. However a relatively high BHP low PI well that is gas lifting with injection near the formations may be getting 90% of the possible production.

If the production restriction is due to an inflow problem, then the efforts to improve on PVPAT must normally be in cost reduction. However, all such wells need to be evaluated for stimulation.

Outflow Restriction

If the well is being produced with a relatively high bottom hole pressure, then it is very probable there is some sort of well outflow restriction. The artificial lift equipment may be limiting the production. Once this condition is recognized, a number of questions need to be answered: What is the maximum possible production? Can the displacement or lift gas be easily increased? Is the equipment loaded? Is the equipment over-loaded? Should a larger tubing string be installed? The final decision often requires input from both engineering and operations. Changing out to higher volume equipment should be evaluated. The conclusion of such studies must be shared by engineering and operations. In general the equipment should be operating at its maximum capacity but not overloaded.

Surface Restriction

Sometimes the production is limited not by the inflow of the reservoir or the artificial lift equipment but some sort of surface condition -- a non-well restraint. These conditions need to be recognized and corrective steps taken where feasible. Surface wellhead chokes, small or long flow lines, and high separator pressures are often causes of reduced production -- due to the increased back pressure on the formation. The reason for any of the above conditions needs to be reviewed and the economics of altering the surface equipment needs to be explored. Other types of surface restrictions that seem to come up from time to time are too small pipeline pumps, inadequate storage, or limited salt water disposal. Again the cost to change this equipment should be evaluated.

Proration has restricted production from many wells in the past and still occurs in places. Many of the states in the USA have or had allowables that limit well production. Usually proration results from governmental action in an attempt to conserve production or to control prices. Usually nothing can be done immediately about proration but to recognize the problem and work towards its solution. In the meantime, reduction of operating costs should be emphasized to increase profits.

As operators, we sometimes impose a restriction on a well for a good reason. The well may be a sand producer and experience has shown that at high rates the well may sand up or erode out the flow lines. Water or gas coning can sometimes be minimized by restricting production rates. Such conditions need to be discussed by engineering and operations. There have been cases where the well was unnecessarily restricted.

MAJOR CONTRIBUTING FACTORS TO PVPAT

Once a well is drilled and completed in a new hydropressured reservoir, it will normally flow for some time period. Two bad things usually happen to wells with time, the reservoir pressure decreases and/or the water cut increases. Thus the rate declines. Once the rate declines sufficiently or the well dies, artificial lift is necessary. Of course, some wells need artificial lift on completion.

Assuming that the well has been drilled and completed, there are three major contributing factors that greatly influence the future PVPAT of any high volume artificial lift installation. These are: 1) capital cost, 2) operating expenses, and 3) net revenue. The capital cost is by far the easiest to determine and is frequently the most scrutinized and skimped on. Operating costs (both direct and indirect) are more important and are difficult numbers to come by. Energy costs can be estimated with some certainty but repair and maintenance (R&M) costs must initially be determined from analog fields. In fields where similar artificial lift systems are already installed, operating and R&M costs can be dug out and used. Net revenue is the most difficult to predict. The future well production decline must be projected and the value of oil estimated to arrive at the net revenue.

A hypothetical example for an artificial lift installation is shown in Figure 1 for an on land well that has the potential to produce 200 BOPD, has a predicted 25% nominal yearly oil decline rate, and reserves of 287 thousand barrels. The well has ceased to flow and must now be equipped with artificial lift. The capital cost for the artificial lift equipment of $100,000 makes up a small part of of the total cost picture. Total operating expenses of $1,000,000 will occur over a 16 year life of which about $500,000 will be in direct operating costs. The net revenue based on current prices will be about $7,500,000 over life. The PVPAT should be in excessive of $2 million if drilling and completion costs are excluded. The emphasis should be placed on getting the reserves and reducing the operating expense. Based on the above, we would recommend selecting a type of lift that: 1) will produce most of the reserves in a reasonable time frame; and 2) is energy efficient and will not have high repair and maintenance costs. The capital cost is the least important as far as PVPAT is concerned. However, it is very important to select the correct type of lift method.

INFLOW LIMITED WELLS

The emphasis on wells that are limited in production by unimpaired inflow from the reservoir should be on reducing operating costs. This is true for both low and high volume producers.

Reduction of pulling costs is often very important, especially where repair and maintenance expenses are high. Repeated rod breaks, short pump runs, cable burnouts, tubing leaks, etc., quickly run operating costs up drastically. Not only must you pay for these expenses, but in addition the economic limit of the well is raised which results in loss of oil reserves.

The following are a few of the steps that should be considered to lower repair and maintenance costs:

- Better equipment selection and design
- Closer quality control and tighter specifications
- Proper installation
- Good operating practices as a result of training
- Proper maintenance
- Supervision of repairs
- Keeping good records to "engineer" needed changes
- Bids on equipment, materials and services

Another excellent way to lower costs is to use less energy. Energy costs have increased significantly and will continue to climb. The following considerations on reducing energy costs are recommended:

- Select more efficient lift systems
- Choose higher efficient components
- Do not oversize electric motors or engines
- Do not over-pump wells; use pump off controls
- Use central electrical metering
- Use correct wire size to avoid I^2R losses
- Design equipment to avoid high friction pressure loses
- Reduce gas interference
- Use more efficient compressors

There are miscellaneous cost cutting means. Some of these can be easily done and others are a major undertaking. Often the changes are in the way the well and field are operated. Central batteries can be installed and in some cases better use of automation may cut costs. Be wary of cutting back in preventive maintenance.

DISCUSSION OF MAJOR ARTIFICIAL LIFT METHODS

The four major artificial lift methods: 1) rod pumping, 2) gas lift, 3) electrical submersible pumping (ESP), and 4) hydraulic pumping will be discussed in more detail.

There are a few major concerns we have for each of these lift methods. Some of you may have experienced the same problems or were smart enough to avoid them. Let us start off with rod pumping.

HIGH RATE ROD PUMPING

"High Rate Lift" is a relative term. Rod pumping is not normally considered a particularly high rate lift system. However use of relatively long stroke units, large plungers, and high pumping speeds need to be reviewed if for no other reason than to establish a norm. To many operators lifting 2500 BFPD from 2000 feet or lifting 1000 BFPD from 5000 feet is a high rate lift situation.

Shallow High Volume Lift

The problems of lifting high rates from shallow wells (less than 2000 feet) are quite different than from deep wells. In shallow wells the major problems are normally with rod fall, large plungers and high peak torques. The API design method (API RP 11L) seems to break down for shallow wells where the non-dimensional pump speed (N/No) and the non-dimensional fluid loads (Fo/Skr) are less than a 0.1 value. The API design ignores flow line pressure and fluid acceleration which are much more significant in determining loads for shallow high volume lift. In design of shallow rod systems we must rely on other design approaches or field experience. In general for shallow high rate lift, install large pumps and run the units as fast as the rods will fall. Larger pump sizes running at slower speeds are more efficient than smaller pumps running at higher speeds. Always check to be sure that the gear box is not overloaded.

Deep High Volume Lift

For relatively deep wells (greater than 6000 feet) the major problems when attempting to lift high rates are normally with high rod loads. The API design method usually gives ball park load answers and predicts the change in loads for different operating conditions rather well. To deal with high rod loads, we are forced to go with higher strength rods such as the API type D or the Oilwell E type rods. It is very important to have a good corrosion inhibition program for rod pumped wells.

The major artificial lift problems will change for each particular well and field and the priorities need to be adjusted accordingly. For most deep fields, the rods deserve to be near the top of the priority list. Too high loads and rod abuse will cause repeated rod failures which in turn will result in extremely high operating costs and excessive down time. Efforts to improve rod life are almost always worthwhile.

Pumping units also deserve to be a high priority item. After all, the units are the most expensive piece of equipment in the rod pumping system. Both the gear box loads and the structure load must be considered. The API design assumes that the unit is in perfect balance which in practice seldom occurs. As water cuts and lift depth increase we have a tendency to overload the gear box. Also at the higher speeds, load reversals become more important. Prolonged overloading of the gear box will result in premature gear box failures.

Keeping the structure of the unit from being overloaded is also important. Bending the beam or failure of the base seldom occurs. Occasionally a base weld may crack but these can be easily repaired. The primary problem with overloading is in the bearings. Doubling the load results in reducing the bearing life by a factor of eight. A bearing failure often results in tearing up the unit structure. If the unit is overloaded steps should be taken immediately to reduce loads or to replace the unit with a larger one. There is always a place for a good second hand unit -- even a small one.

Good surveillance is essential in rod pumped fields when lifting high rates. We are proud in Shell of our computer vans and the excellent surveillance job the Shell van operators perform. These vans record the surface dynameter card and by use of a computer program calculate bottom hole pump cards. Bottom hole cards give one a much better picture of the pumping conditions.

Large Conventional Units

The largest conventional beam rod pumping unit currently manufactured is a C-912D-365-168. Figure 2 is a bar graph which gives the maximum allowed pump rates for various lift depths from 4000 to 14000 feet. In making such a graph one must consider rod loads, structure rating and gear box size. Three different types of rods (all for 3 taper rod designs) are shown: API C, API D, and the Oilwell E. The calculations for this graph are based on API RP-11L.

In general API C rods will restrict production in deep high volume lift wells. At 4000 feet, use of the low strength C rods restricts production to about 750 BFPD whereas use of API D rods (or oilwell E) will allow about 1100 BFPD. In this case the gear box is the limiting factor. Production falls off rapidly as lift depth increases and at depths of greater than 8000 feet the Oilwell E rods permit higher rates. At lift depths of 14000 feet, API C rods are loaded up even under static conditions -- essentially preventing their use at such depths. API D rods are close to their limit; therefore, Oilwell E rods are needed. It is very important to use good rod handling practices when rod loads are high.

Other Rod Units

There are other type rod units and these deserve consideration for deep high volume lift. The Mark II and similar such units have been used by many operators with success. The largest Mark II currently manufactured is a M-1824D-427-216. A M-912D-365-168 is being used to successfully lift a 14500 foot well from near bottom. Such units have improved geometry over conventional units. These special units normally result in reduced peak torques. Some engineers prefer the Mark II unit over all other types.

The biggest beam units available are the air balanced type and one manufacturer lists an A-2560D-470-240 unit. These are expensive units and are somewhat more complicated than a conventional unit. Many engineers restrict air balance use to special applications. Air balanced units make good test units since they are more compact and do not have the heavy counterbalance weights. For this same reason they are better suited for jacket or platform installation. One additional advantage is that these units are easier to balance since all that is required is to change the counter-balance air pressure.

Besides the beam units there are several different types of long stroke rod units. Most of these are designed to give a long slow stroke which is considered a better operating condition for the sucker rods. We have tried these units on a limited basis. We have had both good and bad experience and believe that a long slow stroke is not always the best approach. Units larger than a 168 inch stroke are seldom bought by most engineers. Larger units are much more expensive and can produce only moderately higher volumes.

CONTINUOUS FLOW GAS LIFT

Continuous flow gas lift is an excellent high rate artificial lift system for many fields. Like all lift systems it has its advantages and limitations. One essential requirement is that there must be sufficient lift gas available over the life of the project. A few of the other major concerns (problems) will be briefly discussed.

Tubing Size Selection

The size of the tubing is very important, especially when trying to lift high rates. In order to pick the right size tubing you need to get a good two phase vertical flow correlation. The Ros-Gray or Ros-Moreland (MMSM) correlations are used with good success. The Duns and Ros that is so often referred to in the literature is not recommended for most fields. There are many other correlations that may be suitable. However, no correlation is perfect for all conditions and its accuracy should always be checked with good data from the reservoir where it will be used. Use the correct PVT data and make corrections for deviated wells.

By use of a good two phase flow program, tubing performance curves can be developed for the well or field of interest. See Figure 3. Such curves will quickly show the importance of the tubing size. All these curves have the same general shape. For low rates, the required flowing bottom hole pressure is relatively high. As rates increase, the pressure decreases until it reaches a minimum. Thereafter, the pressure increases more and more as rates increase. This increase is due to friction loss in the tubing. The high pressures at low rates is due to slippage. The size tubing should be picked that corresponds to a rate that is greater than the minimum pressure value and yet does not have excessive friction loss. Picking too small a tubing will result in high friction losses; whereas, picking too big a tubing size will put you in the high slippage range which will cause severe heading in gas lift. Also the larger tubing costs more. Thus there is a range of rates that are suitable for each tubing size for the particular reservoir. For the conditions in Figure 3, the apparent ranges are as follows:

Nominal Tubing Size In Inches	Ideal Production Range In BPD
2	250 to 600
2.5	500 to 1000
3	900 to 1600
3.5	1400 to 2400
4	2000 to 3000+

Based on these data, we often select too small a tubing; however, there are other factors to consider.

Gas Lift Design And Valve Placement

Gas lift design and valve placement is a good news and bad news type problem. The good news is that a working design can be made with little or no data. The bad news is that good data are required to make an efficient design that will produce the well near its maximum potential. Our efforts to obtain PI and injection depths by using pressure surveys have been worthwhile.

High PI wells are very sensitive to the injection depth and require close valve spacing in the vicinity of calculated injection point. Well conditions often change which will result in a different lift depth. Thus to be on the safe side, several additional valves or mandrels should be run in most offshore installations. These extra valves or mandrels may prevent a pulling job. Spacing less than 300 feet is seldom used.

Gas Lift Valves

For high volume lift, say over 2000 BPD, the use of one-and-one-half (1.5) inch O.D. valves is normally beneficial. These larger valves can have a larger port which permits a higher gas injection. Also the larger valves are reported by some to be more rugged, stable and trouble free.

In the typical Gulf of Mexico well that normally produces far less than 2000 BPD, the use of one-inch valves with 3/16 inch ports are usually adequate. Many fields have good luck with one-inch valves. One key is to check to be certain that the valves are aged properly and set correctly without much drift in pressure. Use simple injection pressure operated valves to unload to the point of injection and use a screened orifice for the operating "valve"!

Injection Pressure

Too often the gas injection pressure is selected based on gas sales pressure rather than on a pressure which will produce the well more efficiently. The gas injection pressure needs to be selected that results in the lowest compression horsepower per barrel of fluid lifted <u>when injecting optimum gas volumes</u>. This usually means that the injection pressure must be high enough to lift from near bottom -- just above the packer for tubing flow. By injection near bottom, either more fluid can be lifted (a higher drawdown) or less injection gas is used to lift a given volume. Both of the above will increase profits. The above is especially true for high volume gas lift cases.

A gas lift example is shown in Figure 4 where three injection pressures are plotted on the graph; 600, 1000 and 1400 psig. Also plotted is the equilibrium curve which shows the lift depth and tubing pressure to produce various rates for the given well. For this well, the 600 psig system can only produce about 500 BPD, the 1000 psig system about 800 BPD; whereas, the 1400 psig system will produce about 1000 BPD. In all cases the same injection GLR was assumed. It is obvious that the higher injection pressure will be more profitable in this example.

High Wellhead Back Pressure

High wellhead back pressure is a serious problem in many of our high rate wells. Long or small ID flow lines, high separator pressures, or chokes result in restricting production. These problems need to be identified and then corrected. Not only can production be increased but lift horsepower can be decreased by reducing back pressure on the well.

Optimum Injection Volume

The subject of optimum injection gas has received a lot of attention in the past few years. There seems to be either a lack of understanding or a difference of opinion on just what is the "optimum" gas injection volume. Obviously the injection gas requirements will vary from field to field and even from well to well.

In design of a particular system, the capital cost, the operating cost, and the production revenue over the life of the project should result in the highest PVPAT. Compressed gas is never free since the capital costs for the compressors must be considered. Most operating personnel have been taught to produce the wells near maximum rates and strive to do such. This approach brings Parkinson's gas law into effect. Parkinson's Gas Law: The Field Demand For Injection Gas Quickly Expands to Equal and Then Exceed the Available Compressor Output. This means that regardless of the size compressor installed, operations will use all available injection gas almost immediately and within a short time request additional injection gas. The question is "can this additional compression be justified?" Often the answer is "no."

There are two primary cases in selecting "optimum" injection volumes: 1) system design and 2) gas distribution for a given installation. In the design of the system the "optimum" injection must be determined considering all the costs and revenue. One good way to help analyze this problem is shown in Figure 5 which is for a typical gas lift case. The total injection gas plus formation gas is plotted against the tubing pressure at the planned injection depth(s). With no gas, the pressure at the point of injection is actually the liquid gradient times the depth plus the wellhead back pressure. As the gas is increased the pressure falls off rapidly due to the reduction of the gradient; however, as gas is increased further the pressure decreases much less and the curve becomes almost flat. A significant amount of injection gas can be added and the resulting decrease in flowing tubing pressure at injection depth is small. Finally a minimum pressure is reached which is where maximum production will be obtained. Any further increase in injection gas will increase pressure (and reduce production) due to the fact that the increased friction pressure loss is more than the reduction in gradient head pressure.

Since compressed gas is never free, producing at the absolute maximum production is never optimum. In fact due to the flat curve and high cost of compression, the injection volume needs to be significantly less than the volume to achieve a minimum gradient. One rule of thumb is that the total injection gas should not exceed half the rate to achieve the minimum gradient. We often use an optimum which concluded that the last 5 MCF of injection gas obtain a pressure decrease of at least one psi. Another approach is to design for an operating condition 50 to 100 psi above the minimum pressure.

For a system that is already installed, the injection gas should normally be distributed so that the maximum possible oil production is obtained. There may be some wells that need to be restricted and others that need to be produced even though the gas could, for the short term, be better used elsewhere. The total injected gas per barrel of produced oil is sometimes used for the best injection gas allocation scheme. The better method is to allocate the injection gas so that the last 10 to 100 MCF for each well makes the same amount of additional oil. Each well will have a unique curve of oil produced per MCF of injection gas. When the rate of production per MCF of injection gas is equal for all wells, then the highest PVPAT is being obtained. Often in high volume lift, this results in giving the best oil wells the most gas and the high cut water wells the least gas. If reserves are <u>not</u> lost, then this sort of allocation method is recommended.

<u>ELECTRICAL SUBMERSIBLE PUMPS</u>

Electrical submersible pumps (ESP) have been recognized for years as a high rate artificial lift system. In the past few years its use has increased and in 1983 in the USA as many wells were equipped with ESP as gas lift. If the well conditions are right, then 100,000 barrels of fluid can be produced. The capital is often attractive and some operators report several years of operating life between repairs. Let us discuss some of the concerns and some of the major limitations of ESP's.

ESP is the most "unforgiving" type lift system. All the other artificial lift systems are more flexible and can stand some sloppy operations. The engineering and operating personnel can learn from experience without many disasters on rod pumping systems. An ESP system requires a rather precise rate design, good training of both the engineers and operations, careful equipment selection, correct installation, a reliable electrical system, stable operating conditions, excellent repair and maintenance procedures, and careful selection of the type well for installation. ESP like all pumps do not like sand, scale, or free gas. Despite all of these limitations, ESP is often the only way to go.

The physical size (outside diameter) of the motor is important in most high volume installations. To get the needed horsepower down hole may require large casing. If you have small casing you have already penalized yourself. Larger motor diameters are generally conceded for a given horsepower size to have a smaller capital cost, to be more energy efficient, to be more rugged, and to be cheaper to repair. Thus you need to equip your high volume wells with large casing and install a relatively large motor.

The pump capacity must be carefully selected. Good well PI data are required to select a pump size that operates in the recommended range. If the actual rate is higher than predicted, operating efficiency is decreased and upthrust may accelerate pump wear. You may be forced to choke the well back until the pump can be pulled and re-sized. If the pump capacity is higher than the well inflow, the well will pump off and the under load current will shut you down. If you operate on the low capacity side, down thrust will reduce run life. It is best to operate near the peak efficiency.

In the past few years there have been two developments that have helped in the pump capacity sizing: 1) variable speed drives (VSD) and 2) soft start using silicon controlled rectifiers (SCR). Neither may be God's answer to the ESP problem but these two developments certainly make ESP operation easier.

VSDS have been around long enough that most operators have had a chance to evaluate them. VSDS are expensive and have an efficiency of about 92 percent. The A.C. frequency (Hertz) can be changed, which has a direct effect on speed and thus capacity. As the Hertz is changed, the head varies with the speed squared and the horsepower varies with the speed cubed. One must take care not to increase the speed sufficiently so that the motor is overloaded or to decrease the speed so that there is not ample head. Despite these short comings, the VSDS have given the operator more flexibility in operating ESP in fields where rates are uncertain or where rates change. The VSD also permits a soft start which can reduce failures.

The use of SCRS for soft start and to time cycle the well is relatively new. Most operators have had poor experience in the past with conventional ESP oil well installations that were frequently shut down and started. The problem was mostly electrical, with failures primarily in the cable. Start up amperage spikes 5 to 7 times running current are common and voltage spikes on shut down occur. These spikes were believed to cause failures in any weak spots in the down hole electrical system. By use of SCRS, a soft start that results in current peaks of only 2 to 3 times running currents (see Fig. 6) occurs and voltage spikes on shut down are negligible. These SCRS are only used during shut down and start up so that normal system efficiencies are not reduced as with the VSDS. Also the cost of the SCRS is only about half of the VSDS. So far we have had good success in time cycling wells equipped with SCRS.

Another major problem with ESP systems has been in high temperature (greater than 200 F.) oil wells. Such conditions often result in deep wells that are producing high volumes. Conversely we have had few problems in producing water wells with temperature below 150 degrees Fahrenheit. The problem is mostly with the cables. Some cables are rated up to 350 F. However, most operators have serious doubts that long cable life (greater than 5 years) can be obtained at such high temperatures. Even at 200 F., special cables and handling are required to get a reasonable cable life. Better cables for high temperature wells still need to be developed.

Most operators believe that considerable effort must be put into any ESP operations to obtain reasonable repair and maintenance costs. If such costs can be kept under control, ESP is an excellent high volume artificial lift method. Training and operating procedures are extremely important in ESP operation.

HYDRAULIC PUMPING

Hydraulic pumping has been used for over fifty years for artificial lift. However, its use has always been limited and its share of the market small. Our peak use was in the sixties when they were used rather widely in Montana, Wyoming, California, Texas and Mississippi. Many of these installations have now been converted to other lift methods. Hydraulic lift would probably be recommended today only on a default basis where other lift methods would have serious problems. Hydraulic pumping does have some unique advantages but also some severe limitations.

Hydraulic pumping has the ability to pump relatively high rates from great depth and the capital costs are often competitive with rod pumping. The pumps are not overly sensitive to temperature. Also by use of the free type pump, well pulling is infrequent. Corrosion control by inhibition is easily done and the displacement can be easily changed. Deviated holes present few problems and wells can be operated with either central control or individual control systems. With all these good features why is hydraulic pumping not more widely used?

One of the principal draw backs to use of hydraulic pumping is that the operating costs will be higher than rod pumping -- unless there is some special problem. On low to moderate volume wells, rod pumps do a better job of pumping the well down and in handling moderate volumes of gas than hydraulic pumps. Also the operating personnel seem to have a more difficult time in efficiently operating and understanding hydraulic pumping than rod pumping.

In higher volume wells, hydraulic pumping has a difficult time in competing with ESP where temperatures and lift depths are <u>not</u> high. In many offshore locations, hydraulic pumping cannot compete with gas lift where GLRS are high, sand production is common, and gas venting up casing is not desirable. Thus it turns out that hydraulic pumping is frequently eliminated by some well condition or someone's prejudice. Short pump runs and high operating costs are enough to make one prejudiced.

Another disadvantage to hydraulic pumping is that central accurate production surveillance can be difficult in open-loop central systems. Since power fluid and produced fluid are mixed together, produced fluid volumes are calculated by taking the difference between measured power fluid in and the total fluid produced from a well. Produced oil volume accuracy is particularly a problem in high water cut wells using oil as the power fluid.

High hydraulic pumping cost can often be reduced by proper design. Surface pumps for the power fluid are usually triplex or quintuplex piston pumps that are rated at 5000 psi. Operating costs can be kept much lower if pressures are kept under 3500 psi when pumping water and under 4000 psi when pumping oil. Some engineers recommend values that are 500 psi less than the above. The maximum pump speeds recommended by the manufacturer are often too high -- possibly as much as 25 percent. Again, keeping the pump speed down will give better pump life. Avoid high friction pressure losses by sizing the lines and tubing properly. Small casing size often prevents using the size tubing needed, thus resulting in more friction losses and possibly causing difficulty in venting gas. If gas is to be vented, two tubing strings are required which complicates completions.

Often the short runs for hydraulic positive displacement pumps are due to poor power fluid quality. Experience has shown that these pumps require clean power fluid -- less than 10 PPM solids with sizes less than 15 micron for long pump life. Settling tanks or centrifugal desanders can be used to clean the power fluid but must be designed and installed properly. Salt deposition has in some fields reduced pump life when using power oil. Salt deposition can usually be controlled by injecting a small volume of fresh water in the power oil.

Development of the jet production unit in the mid 1970's has improved and broadened the use of hydraulic pumping installations. These units have no moving parts -- using a nozzle-throat-diffuser arrangement to convert a velocity head to a pressure head. Unit life is excellent and power fluid does not have to be ultra clean. Use of jet units in lieu of hydraulic pumps has frequently reduced pump operating costs and simplified operations. Also jet units are a high volume artificial lift method suitable for many well conditions.

Jet units, however, are not very efficient and will require more energy input. They cannot be used effectively at low suction pressures due to cavitation problems. They will handle only a moderate amount of free gas without a further loss in efficiency. Do not expect jet units to compete on low volume wells with rod pumps unless there is some special problem. However, jet pumping may compete with gas lift in some high volume lift situations.

CONCLUSIONS

1. For operation of wells on high rate lift, one must first determine the factors that most affect the PVPAT. A priority list needs to be established. In most cases the production of the oil reserves in an expedient manner is the most important consideration. Operating costs are also very important and steps need to be taken that will keep them low. The capital cost of the artificial lift system should not be skimped on where the choice could result in restricting production rates or in lowering efficiency and increasing maintenance cost.

2. The type of production limit needs to be defined. The three types of restricts are (a) inflow (reservoir production limit), (b) outflow (equipment capacity limit), and (c) surface (constraints). For inflow and surface limit cases, one must concentrate on reducing operating costs. For the outflow limit case, one must try to get the most out of the available equipment and/or consider equipment changes.

3. The best type of lift system should be selected for the particular well and field. Rod pumping is the standard onshore operation; whereas, offshore the standard is gas lift. ESP is a good choice in many cases. In special cases hydraulic pumping may be the only suitable choice.

4. Design the equipment so that it will not be overloaded and, if feasible, so that the well is pumped down.

5. Proper installation of the equipment is necessary. ESP installations require special attention by both engineering and operations.

6. Spend ample time on surveillance to evaluate each artificial lift installation on a periodic basis. Well conditions change and equipment modifications are often needed for efficient operation.

7. Use good repair and maintenance practices. More attention should be given to the pulling and running procedures and to repair shops.

8. Do all of the above and the high rate lift installations should result in a high return on your investment.

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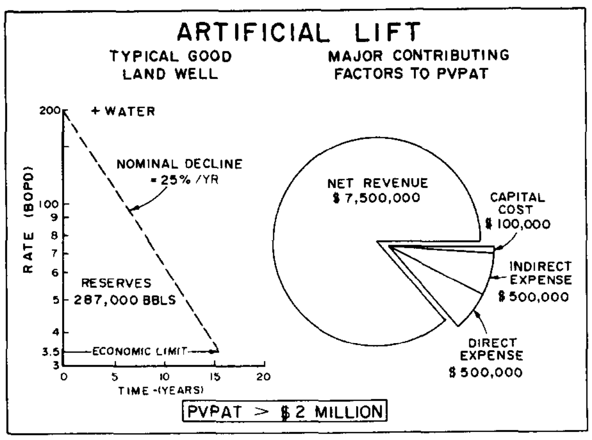

Figure 1

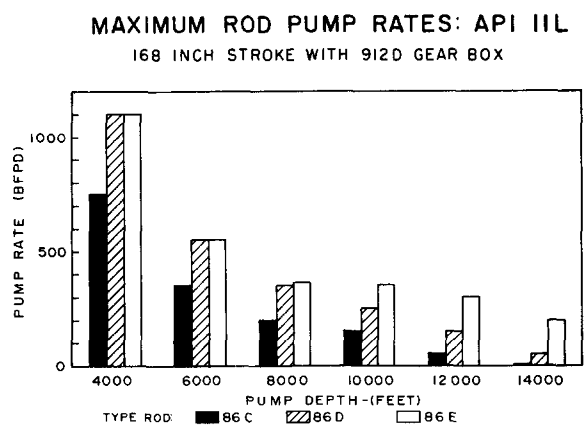

Figure 2

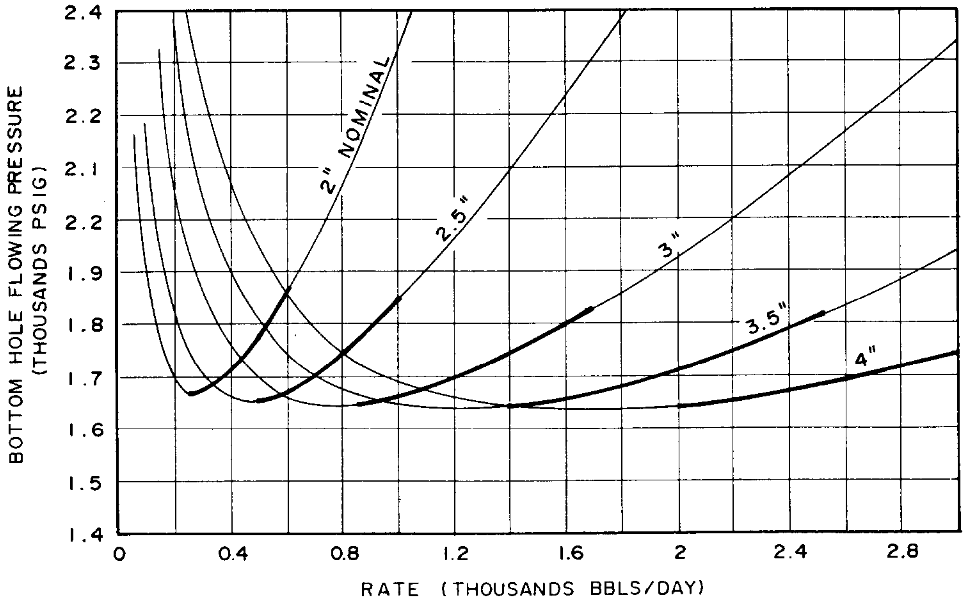

Figure 3 - Tubing performance curves - 10,000' well with 1000 GLR

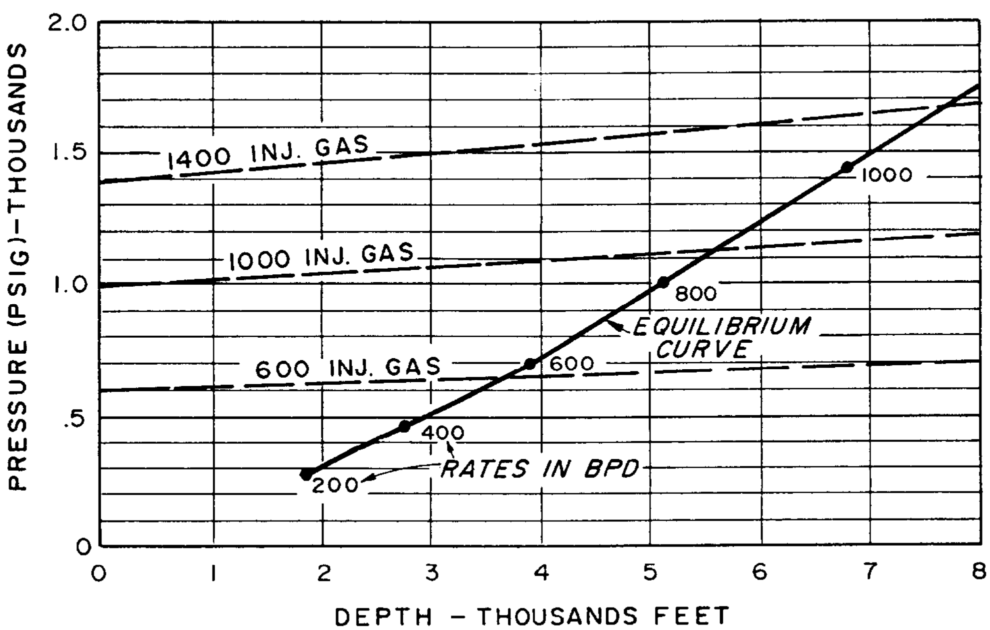

Figure 4 - Gas injection pressure selection - Gulf Coast gas lift design - good well

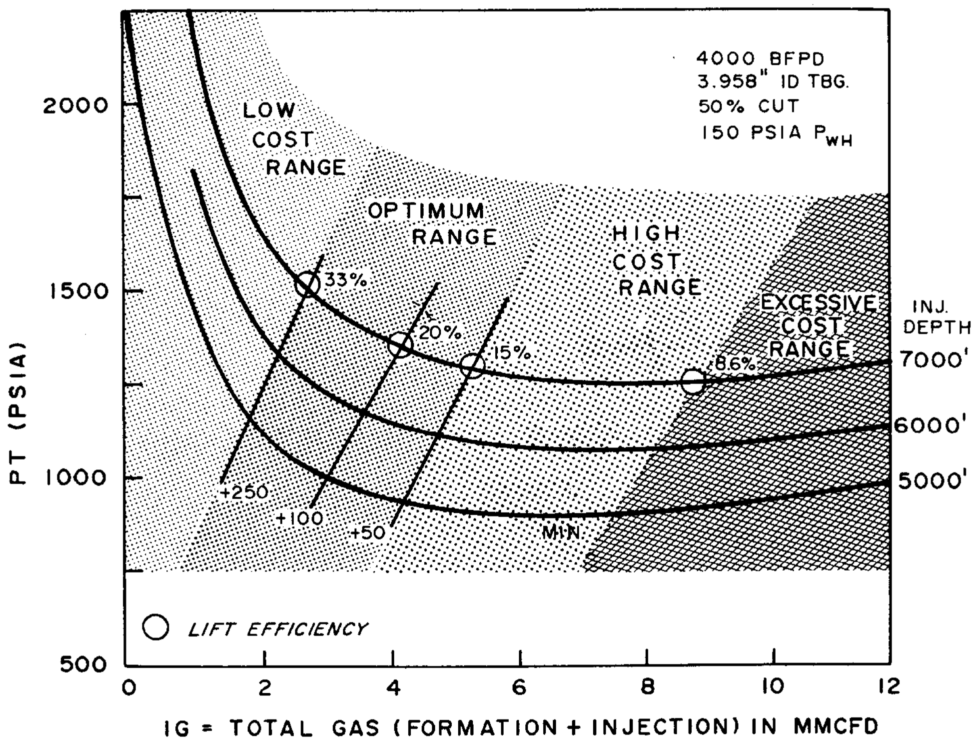

Figure 5 - Gas lift performance

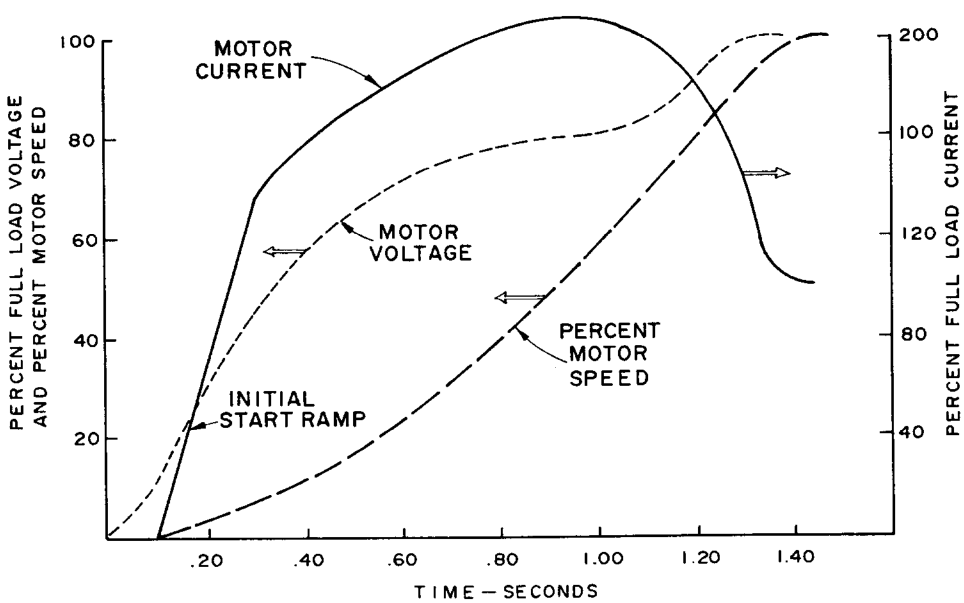

Figure 6 - Motor parameters for an actual soft start