DISCUSSION PANEL

Selection of the Proper Type of Artificial Lift

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MR. ZABA

I think that it is time we started now. Beginning on my right is Mr. Jerry F. Boutwell with the Reda Pump Company, who will, as you suspect, talk about the "Reda Pump." Mr. R. W. Reekstin of the Axelson Manufacturing Company of Los Angeles will talk about "Long Stroke Hydraulic Pumping." Mr. H. W. Winkler of Camco Incorporated in Houston will talk about "Gas Lift." Mr. R. G. Ralph of Kobe Incorporated in Huntington Park, California, will talk about "Hydraulic Subsurface Pumping." Mr. Douglas O. Johnson of Johnson -Fagg Engineering Company in Tulsa will talk about "Sucker Rod Pumping." Mr. C. D. Richards of the Lufkin Foundry and Machine Company of Lufkin, Texas, will speak also on the subject of "Sucker Rod Pumping."

We plan to do it this way. We will start with the subject of Sucker Rod Pumping, since it is the oldest, about 3500 years old. Then we will go to Hydraulic Pumping, which is not so old, then to Gas Lift, then to the Reda Pump.

Mr. C. D. Richards will start.

MR. RICHARDS

I am supposed, for several reasons, to present the case for sucker rod pumping before this panel, but mainly because I believe that the sucker rod type of pumping, when you consider the choice of artificial lift, has the inside track, and has had the inside track for many years. Approximately 86 percent of all the wells that are on artificial lift in the world are on some type of sucker rod pumping. Now that has been true for at least thirty years and I suspect that it has been true for even longer.

There is nothing new about the sucker rod deal. It is 3500 years old, but I am only going to go back about fifty years to the beginning of the oil industry as we know it. The oil industry did not really come of age until about the turn of the century.

The sucker rod type pumping unit is any mechanism that gives a reciprocating motion to a string of sucker rods, which in turn actuate a bottom hole pump and lift fluid from a well. It has a number of advantages and I will run over them rapidly. The first of these is the low first cost. This is made possible because pumping units are manufactured in great numbers and standardization and volume production has cut the costs. Secondly is their wide range of application. By that I mean that they are applicable to almost every well condition that might be encountered. I am sure that this is going to come up so I may as well mention it first. They are not so hot for crooked holes, but for almost every other condition they are almost impossible to beat. There are very few cases where sucker rod pumping equipment falls down and fails to work.

Thirdly there is simplicity of operation. They are the very simplest type of mechanism and hence they are no problem for field personnel. And this ties in with the fourth advantage which is low maintenance cost. Pumping units are very rugged and simple in design and are well understood by most of the operating personnel throughout the world. This leads to low costs. One manufacturer with 60,000 units in operation has an annual parts business of $300,000. That is only $5.00 per unit per year for repairs.

The fifth advantage is long life. The life of sucker rod type pumping equipment -- I am talking now more of the crank type unit -- is thirty to fifty years. High salvage value is the sixth advantage, and an important one. A Pumping unit has high salvage value for the same reason that it has long life. It is a very rugged type of equipment and if properly sized in the first place and properly maintained and lubricated, the salvage value should be at least fifty percent after even twenty or thirty years of operation.

There are two general types of sucker rod pumping units which I will mention. One is the beam type unit, which is the most commonly used, and the other is the hydraulic unit, which will be discussed by another speaker. Now the beam type units are distinguished from each other by the type of counterbalance employed. There is the rotary type with the weights on the crank, and the beam type with the weights on the beam. Then there is the combination of the two. In addition there is the air balanced unit which uses compressed air as the means of counterbalance.

Now of all the advantages that I have listed here, I feel that actually the one advantage that I have not listed is really the most important, and yet it is not exactly the same type of advantage as those that have been set forth so far. What I am speaking of is this. The oil industry is the most curious, the most long suffering, the most willing of any industry in the world to try anything new. They will try anything that you might put out if there is the least chance that it is an improvement over the way that the job has been done in the past. Despite this curiosity and this all consuming interest in doing everything in a better way if it is possible, sucker rod pumping has stood up and maintained its 86 to 90 percent predominance ever since the beginning of the industry. And, to me, that is the greatest argument for the use of sucker rod pumping.

I am not going to stand here and tell you that there is no better way to pump a well. I think that some day there will be a better way found. Until that day arrives I believe that the best method is sucker rod pumping.

Thank you.

MR. ZABA

Thank you very much Mr. Richards. Now our next speaker is Mr. Reekstin of the Axelson Manufacturing Company of Los Angeles, who is going to speak on Hydraulic Long Stroke Pumping.

MR. REEKSTIN

The subject today actually covers two phases of the hydraulic pumping system -- the long stroke as well as the medium stroke pumping unit. Under the subject of the long stroke pumping unit, it was born of necessity. In the early thirties, wells rarely reached depths exceeding 7000 feet. However each succeeding year brought new record depths.

When it became necessary to produce these wells with a subsurface pump and sucker rod string it became obvious that larger, more massive beam-type surface units would be required. The surface unit was transmitting only 55 to 80 percent of its reciprocating motion to the subsurface pump. The hydraulic long stroke unit was developed in this era.

All hydraulic pumping units basically consist of the following parts: Working piston and cylinder, power pump, fluid reservoir, and valves and piping.

The length of the surface stroke is governed essentially by the length of the well cylinder. The working piston rises and carries the sucker rod string with it. Today, wells 10,000, 11,000 and 12,000 feet deep are successfully pumped with units of this type. The rods continue to stretch, as with beam units. However, the stretch is only a small percentage of the available stroke. Consequently, surface displacement of a hydraulic unit could be decreased appreciably and still maintain comparable subsurface displacements to that of a mechanical unit.

Surface polished rod velocities of up to 370 feet per minute are available with the hydraulic long stroke unit. The surface displacement coupled with a cycle rate of 7 CPM provide more barrels of oil than ever before possible.

Experience garnered from many field operating units has shown a considerable improvement to sucker rod life. Breaks were less frequent. The sucker rod string was stressed upwards to 40,000 psi and continued to provide a good economical life. The evidence indicates that the constant polished rod velocity, hydraulic dampening and hydraulic reversal are all beneficial to the sucker rod string. The low cycle rate all but eliminates the danger of synchronous pumping.

The ratio of brake horsepower input to brake horsepower output is more than with a mechanical unit. There are fundamental losses in a hydraulic unit which have been minimized, but will never be eliminated. The power pump can operate at efficiencies up to 88 percent. Fluid friction within the piping contributes to additional losses. Fluid slippage past the working piston and the various valves further reduces the efficiency of a hydraulic unit. Realistically, we think of the efficiency as about 68 percent.

Again, on the plus side, there is still an additional advantage to the hydraulic unit. Because of the extremely long subsurface stroke, a high compression ratio is available. With proper subsurface spacing "gas-locking" is eliminated.

The long, slow stroke provides maximum control in wells where sand may have been a problem. A more uniform flow rate into the pump chamber results from use of the long stroke unit.

Still another type application where the long stroke unit is economically feasible is on the medium depth well where water encroachment has become a problem or water flooding has made it necessary to produce high volumes of fluid. A large bore pump operating under the long stroke unit will produce several thousand barrels per day. Peak rod stress as well as stress range on an installation of this type is high but, here again, the hydraulic actuation reduces rod fatigue failure.

Among the medium stroke pumping units a counterbalanced 10 foot unit is manufactured and is successfully being operated on many wells. However, the medium stroke unit herein referred to is the non-counterbalanced type.

The establishment of a constant flow characteristic from the well formation to the well bore will yield maximum crude production. A slow, constant upstroke speed, coupled to a fast downstroke approaches the ideal pumping cycle. Hydraulic units are currently in use having 4, 6 and 10 foot strokes with the aforementioned pumping characteristic.

The upstroke is the power portion of the cycle. A volume of fluid under pressure sufficient to raise the rod string and production crude is supplied by a positive displacement pump to the underside of the working piston. During the downstroke the weight of rods acting through the working piston discharges fluid from the underside of the piston back to the fluid reservoir.

The upstroke portion of the cycle may be controlled by means of pump speed. In some instances, a change of internal pump components may be used for controlling the upstroke speed. The downstroke speed is controlled by means of valving; orificing the fluid being returned to the reservoir.

This variation of time between the up and down portion of the cycle is advantageous to a user. The slowly rising subsurface plunger allows an optimum fill within the pump chamber. Hence, maximum pump efficiency. On the downstroke the plunger is allowed to drop rapidly, transferring the fluid to the production fluid column.

The slow upstroke is considered advantageous where fluid levels are such that gas in solution, if not pumped properly, may reach a bubble point in passing into the pump. The slow upstroke plunger motion allows the formation crude to enter through the standing valve with a minimum velocity. Hence, gas in solution will remain in solution. Of course, on the downstroke this fluid within the pump will be ejected through the traveling valve at a rapid rate and gas may come out of solution at this point, but it will result in no loss of efficiency of the pump.

Units of this type are ideally suited to pumping viscous crude. Here, again, the upstroke speed is fundamentally determined by the speed at the pump. The downstroke speed is dependent on the rate at which the rod string falls through the viscous crude. These units are extremely efficient when producing a highly viscous oil.

Sucker rod stresses may be raised appreciably when utilizing units of this type. Here, again, the hydraulic fluid tends to "dampen" any extraneous dynamic forces.

These units are probably the easiest type to adapt to a sucker rod string. The working cylinder mounts over the well. Generally, the cylinder is mounted on a pedestal member which in turn is attached to the well-head. The pedestal type assembly is considered essential in that it prevents the encroachment of well crude into the hydraulic circuit via the well-head polished rod. The well-head polished rod does not enter the hydraulic cylinder when using a spacing member.

The power pump, fluid reservoir and prime mover are unitized. The assembly can be located any reasonable distance from the power cylinder and requires no foundation. The reservoir assembly and well-head cylinder assembly may be moved from one well to another without the necessity of surface remedial work.

MR. ZABA

Thank you, Mr. Reekstin. Our next speaker is Mr. Douglas O. Johnson of Johnson-Fagg Engineering Company, Tulsa, Oklahoma.

MR. JOHNSON

Generally, speaking of sucker rod pumping and its troubles, it is always assumed that if you could just stop sucker rod breaks, all the pumping problems would be over. So all the other devices that are used in competition to sucker rods come out and it is claimed that they have eliminated sucker rod breaks. Of course they have, they don't use sucker rods, but they have other troubles that are just as bad.

Again, looking over sucker rod pumping in general, and suppose that you are going to equip some leases for sucker rod pumping. You must remember that you immediately have the opportunity of getting information from a great many sources. You have a lot of manufacturers competing for this type of business. They are all going to give you the best information they can and they are all going to be very competitive in their bids for those installations. Also, you will have extreme flexibility in those installations. You will have all the various stroke lengths, you will have long-strokes, and short-strokes, and you will have any conceivable combination you want.

Also, because there are so many manufacturers making sucker rod type equipment you will have ready access to parts, services, and repairs even in the most remote areas. In other words, when you get away out; when you get a wild cat well somewhere, generally you put it on sucker rod pumping because you know that somebody will come there and bring equipment to your location.

Sucker rods themselves are keeping pace. They are being continually improved by research. Use of corrosion inhibitors and better steels have eliminated sucker rod failures where they used to be very prevalent.

That brings us to this fact that it is easy to make some improvements in sucker rod pumping because it is easy to make measurements of loads and to see what is happening and to do something about it. That isn't as true in some other types of artificial lift. It has been said before, and I would like to repeat, that sucker rod pumping can be applied to almost any well. There are probably a few exceptions. It may be a very crooked well, it may be a well that makes an extremely high volume of fluid where it is impossible to run a sucker rod system above certain speeds. The field men in the operation of a sucker rod system can understand what is going on. Repairing a sucker rod system is not a big mystery to the man out there - the pumper - he understands what is going on. Now with some other types of equipment he doesn't know just exactly what they are doing, or what they are trying to fix. This is no help in keeping it operating.

Now in addition to the various sucker rod manufacturers and the various pumping unit manufacturers, there are a great many companies engaged in the manufacture of pumps that can be used in the sucker rod system. This gives you the advantage of a lot of research, and gives you access to pumps that will pump a lot of sand, pumps that will withstand a lot of corrosion, pumps that will give you high volume when you need it. You can run in the same string of tubing various sizes of plungers to match the ability of the well to produce. You can install a double displacement pump in and get considerable more volume out without changing the tubing size.

Since we have such a big percentage of wells operating with sucker rod pumping, we believe that sucker rod pumping is here to stay. The percentage hasn't changed greatly over the last few years for the simple reason that sucker rod pumping has been improved. When some of the other methods first came out, they would put their very best technicians out there to watch what was going on and to prove that their system was better than the sucker rod system, and they would leave the sucker rod system to itself. They are having a bigger battle now. Competition is greater because somebody is out there watching these sucker rod wells and doing something about improving sucker rod pumping. Competition gets keener all the time, but we do have in the sucker rod system such a wealth of information, so many sources of information, that it is rather easy for the sucker rod system to stay ahead of the rest. I'll say that the sucker rod system is not going to be put out of existence. It is going to improve and it is going to be more difficult for the rest of those fellows to compete with it.

MR. ZABA

Thank you, Mr. Johnson. I notice that this completes the case for sucker rods. The next speaker will be Mr. R. G. Ralph of Kobe, Incorporated, Huntington Park, California, who is going to talk about "Hydraulic Pumping."

MR. RALPH

We in the Hydraulic Pumping business have no quarrel with the oldest common method of artificial lift, the so called Sucker Rod Pumping System. In fact the Hydraulic System has much in common with the Sucker Rod System. Both Systems utilize power equipment on the surface to drive a reciprocating, positive displacement piston type pump which is installed in the well bore, usually near the bottom. The essential difference in the two systems is found largely in the method of transmitting the surface power to the piston type pump in the well bore, where the power is required to force fluid to the surface.

In the Sucker Rod System a prime mover furnishes power to drive a device to obtain a reciprocating motion on the surface at the well head. This reciprocating motion is imparted to a string of sucker rods which extend from the surface down the well bore to the location of the piston pump near the bottom of the well. In other words, the surface power is transmitted by the mechanical means of full string of reciprocating rods (usually several thousand feet) to the subsurface pump where the power is required to lift the well production.

In the Hydraulic System a prime mover furnishes power to drive a high pressure pump which may or may not be located near the well head. This pump puts crude oil under pressure and thus transforms the output of the prime mover into hydraulic power which is conducted through lines to the well head and down through tubing to a small, fluid driven engine located at the pump-setting near bottom of the well. The fluid powered hydraulic engine is used to furnish reciprocating motion to a piston type pump. In other words the surface power is transmitted by hydraulic means through tubing at constant pressures to the hydraulic reciprocating engine located at the bottom of the well and at that point the power is imparted to the reciprocating pump where it is available to lift the well production.

As noted, there is much in common between the Sucker Rod Pumping System and the Hydraulic System, for in the hydraulic system there is also a rod connection between the reciprocating device and the bottom hole pump. I have with me this rod connection for the most commonly used size Hydraulic Pump installed in West Texas and would like to show it to you now. The length of this rod is 22 inches, yet compares with and performs the same function as several thousands of feet of rods in the average so called sucker rod system. The weight of the rod is 17 ounces, and is comparable to the thousands of pounds of reciprocating rods of the average sucker rod system. The Hydraulic System thus does not eliminate the rod connection between the power driven reciprocating device and the positive displacement piston pump at the bottom of the well. It does, however, reduce the mass and length to such an extent that most of the well known operating difficulties and limitations of the long Sucker Rod System, such as rod wear, breakage, fatigue, and tubing fatigue and wear are eliminated.

The transmission of power hydraulically through proper sized lines is notably efficient. Surveys show that in a properly designed and operated hydraulic system, the overall mechanical efficiency is approximately twice as high as any other currently used system of artificial lift. Obviously, this results in a smaller horse power demand on gas engine or electric motor for a given job.

As power can be transmitted hydraulically with only small losses, the surface equipment of the hydraulic system may be located any place on the lease the operator chooses. Generally the power equipment is located near the tank battery where a source of clean crude oil is available for power oil. Much of the success of the Hydraulic System depends on clean crude oil to be used for power oil, which usually is readily and economically attained.

By locating the power unit near the tank battery it is also common practice to operate the several wells on the lease from a common power header. Thus, depending on the power required for each well, several wells may be operated by a single power triplex pump. This type of central power operation may be carried out even though each pump on the lease requires a different operating rate or speed.

Rate of operation of each pump is controlled by a separate control valve in the power header which governs the amount of power oil flowing to each well. The more power oil forced to the well, the faster the subsurface unit will operate.

One feature of the hydraulic system which the operator has found to be of particular value is the "Free Pump". The term "free" has reference to the manner in which the subsurface production unit (hydraulic engine and pump) is inserted and removed from the well. By the proper arrangement of tubing strings in the well and valves on the surface, the hydraulic power available on the lease during pumping operation may be used to retrieve the subsurface pumping unit. This operation may be done by one man without special tools. This feature also eliminates the well down-time which would normally be required to schedule heavy hoisting equipment and crews to the well head in the event of subsurface pump failure.

The short drive rod connecting the fluid engine piston with production piston in the hydraulic subsurface pump permits the accurate control of the length of stroke. This control results in "full travel" of the production piston on each stroke regardless of the depth of the well or changing production conditions. The displacement of the pump in the well is thus known for any pumping speed and volumetric efficiencies of the subsurface equipment can be readily calculated.

The full travel of the production piston coupled with other design features allowed for design of a pump which cannot be "gas locked". This control over piston travel together with the relatively short drive rod makes it also possible to design the subsurface hydraulic pump so as to intake and discharge on the upward travel of the piston only or to intake and discharge on both the upward and downward travel. Hydraulic pumps of both these arrangements (single or double acting) are in service at the present time.

Some other characteristics of the hydraulic pumping system which are of note permit the lifting oil from great depths, pumping large volumes, efficient pumping of crooked or directionally drilled wells, artificial lift application to town lot requirements, economical establishment of accurate subsurface data such as bottom hole pressure and productivity index by use of a bomb attached to the "Free Pump", etc.

In summation, the hydraulic pumping system is outstanding for its efficient application of power in a difficult power transmission problem, and for the ease with which its design can be altered to meet specific well problems. It has been proved as concerns its field application, and does offer major operating economies to the producer. It is therefore inevitable, I think, that there will be a continuing swing to hydraulic pumping.

MR. ZABA

Thank you, Mr. Ralph for your statement of the case of hydraulic pumping. Our next speaker Mr. H. W. Winkler with Camco, Incorporated, Houston, will talk about "Gas Lift."

MR. WINKLER

It appears that we only have about 15 percent left, according to Mr. Richards, and I am sure that he has looked it up. I have often wondered about the percentage of wells that are on gas lift. It is a relatively new form of lift. However, it has been employed off and on for years, but the present application is relatively new. In my brief discussion, I have divided it up into four major topics. First of all will be the definitions of gas lift, intermittent lift and continuous flow. I would like to follow that with the necessity of flow valves for the majority of gas lift installations. Then the advantages and limitations of gas lift are enumerated. I was asked also to give the limitations and the primary considerations for an efficient installation.

Gas lift is the supplementing of the formational energy with high pressure gas for the continued production of fluid from the reservoir. The high pressure gas can be applied for intermittent or continuous flow depending upon the producing characteristics of the well to be lifted. Some of the factors entering into the proper selection of the form of gas lift to be employed are: producing rate, productivity index, depth of lift, injection pressure, etc. Wells with good P.I.'s are normally produced by continuous flow and those with low P.I.'s and low producing rates are intermitted. A "rule of thumb" for selecting the proper type of gas lift is to continuously flow wells with a P.I. above 0.5 and a producing rate of 200-300 barrels of fluid per day, depending upon the tubing size. This is strictly a generality because many wells are being continuously flowed with lower P.I.'s and many are intermitted with higher P.I.'s than 0.5.

Intermittent flow is obtained by injecting gas of sufficient volume and pressure into the tubing to lift a column of liquid to the surface with a minimum of slippage and fall-back. This type of lift is similar to the principles of ballistics. The column or slug of liquid is comparable to the projectile and the gas to the powder.

Continuous flow is the controlled injection of gas into a fluid column to provide sufficient aeration to obtain the flowing bottom hole pressure for the desired rate of production. A tubing pressure control can be employed on wells which require little stimulation to flow. The tubing cut-off shuts off the injection gas as the tubing pressure increases when the well begins to flow.

There are two basic types of flow valves, namely the differential valve and the pressure operated valve. Since the differential valve has limited application and is seldom used, it will not be considered in this brief panel discussion.

The pressure operated valve is the most widely used valve in the oil industry. Although this valve varies in construction depending upon the manufacturer, the operating principles are similar to a pressure regulator. The valve can be set to open at any desired pressure. When the pressure opposite the valve exceeds the opening pressure, the valve opens. When this pressure declines below the closing pressure of the valve, the valve closes. Generally these valves are set at consecutively lower opening pressures with depth. The decreasing opening pressures with depth permit operating from a deeper valve without opening the valve above.

The reasons why valves must be used in the majority of gas lift installations are:

1. Working down with nominal pressure is possible. For example, the ratio of the volume of 2-in. tubing to the annular volume between 2-in. tubing and 5 1/2-in. O.D. - 17 lb. casing is approximately 4.6:1. If the injection pressure would support 1200 feet of fluid, the bottom of the 2-in. tubing could be submerged only 215 feet below the fluid level for gas lift operations if this fluid level were over 985 feet below the surface.

2. Valves provide the flexibility needed for a fluctuating bottom hole pressure. Most wells will have declining BHP with depletion. If the installation were designed based on submergence without valves, the tubing would have to be con-

tinually lowered to compensate for the declining BHP.

3. Valves permit controlled metering of the gas into the fluid column to prevent excessive injection gas-fluid ratios. This consideration is particularly important in duals where both zones are being gas lifted with a common injection gas source and in open type installations where the well is being gas lifted by continuous flow without a packer.

4. Valves prevent excessive casing pressure bleed-down between gas injections.

5. Valves provide an adequate volume of gas under the liquid slug for intermitting lift by utilizing the volume of gas stored in the casing annulus between the opening and closing pressures of the valves.

6. Valve ports do not cut-out as tubing buttons frequently do because the check valves prevent washing action and the operating valve is open only during surface controlled gas lift operation.

7. Flow valves and mandrels are designed to prevent cutting holes in the casing and tubing.

The primary advantages of gas lift are:

1. The initial equipment cost is low provided high pressure gas is available. When high pressure gas is not available, a closed rotative gas lift system can be installed. The economic advantages of a closed rotative gas lift system increases as the number of wells in the system increases.

2. Gas lift is readily adaptable to deep wells. There are numerous gas lift installations in which the point of gas injection is below 10,000 feet.

3. High daily producing rates are possible with gas lift. Approximately 20,000 barrels of fluid per day have been reported produced from a single well in the Mara Field in Venezuela.

4. Gas lift offers complete flexibility. If the production from a well varies from several hundred barrels to only a few barrels of fluid per day during its producing life, the gas lift installation can be designed to efficiently lift this well to depletion. Admittedly, the pump can pull the bottom hole pressure lower than gas lift, but the economic limit for artificially lifting most deeper wells does not require this drawdown.

5. Abrasive material in the produced fluids does not appreciably effect the operation of gas lift equipment. Some gas lift wells produce such large quantities of sand that these wells require special sand traps on the surface.

6. Gas lift is readily applicable to a directional or crooked hole.

7. Retrievable gas lift valves reduce maintenance costs because it is not necessary to round trip the tubing for valve replacement. Higher over-all operating efficiency can be maintained because the valves and auxiliary equipment can be inexpensively replaced or adjusted to fit fluctuating well and field conditions.

8. Gas lift permits controlled back pressure on the formation. Some wells will load up and die when the rate of production is restricted to prevent excessive drawdown. Injection of a small volume of high pressure gas provides the additional stimulation needed to flow the well.

9. Gas lift is readily applicable to off shore installations. This application has become more widely used with the introduction of completely retrievable wire line gas lift equipment.

There are other advantages for specific cases:

1. An example is a high pressure gas well in the center of an oil field with no sales outlet for high pressure gas. Since there is usually a market for low pressure gas in the regulated oil fields of today, the operator could place his artificially lifted wells on gas lift and sell the gas from the gas well at trap pressure after it had been enriched lifting the oil.

2. Another example is the operator with wells located near a high pressure gas sales outlet who desires to gas lift his wells but has no high pressure gas in his field. This operator can design his compressor installation to permit the sale of all excess formation gas from the high pressure side of the closed rotative system. The additional profit derived from the sale of high pressure gas will substantially aid in the justification of the initial capital outlay for purchasing the compressor plant.

In addition to the known advantages, there are unusual well problems which will favor gas lift under certain conditions. A slight variation in conditions for the same general problem may favor another form of artificial lift. Some examples are:

1. Wells producing a low gravity, extremely high viscosity oil. This type of crude is generally very sensitive to temperature. Gas lift has proven to be the best form of artificial lift for the high viscosity crude from the West Montalvo Field south of Ventura, California. The high rate of fluid production maintains a flowing temperature safely above the pour point temperature.

2. In areas of highly corrosive water such as the Excelsior D-2 Pool north of Edmonton, Canada, the subsurface pumping equipment lasts for approximately two weeks. Conventional gas lift valves which are in the casing annulus would not be subjected to the corrosive water after the well had initially unloaded.

3. Gas lift is considered detrimental in wells which have a paraffin problem. However, gas lift in conjunction with a plunger will prevent the formation of paraffin on the tubing wall.

4. Deep wells with a high P.I. and low bottom hole pressure represent the most difficult type of well for lifting large volumes of fluid by gas lift. However, these wells are also difficult to pump, particularly if they produce sand or excessive formation gas. The type of artificial lift employed must be based on lifting cost which has favored gas lift in many instances.

The limitations of gas lift are:

1. If there is little or no gas available, it is impossible to gas lift.

2. In fields where the wells are on 80 to 160 or more acre spacing, the costs of injection and gas gathering lines become excessive as compared to individual pumping units.

3. The cost of gas lifting an isolated well which would require a compressor installation is generally prohibitive.

4. Some reservoirs are produced with vacuum pulled on the casing annulus of the wells. Gas lift is not recommended for artificial lift in these fields such as the Santa Fe Springs, Signal Hill, etc., in California.

5. Artificial lifting of shallow wells which have no pumping problems and no high pressure gas available will usually favor pumping. This type of well requires small pumping unit which can be operated for short time cycles by an electric motor with very little power cost.

The primary considerations for an efficient gas lift operation before the equipment is installed are as follows:

1. The installation should be designed from reliable well data. A pressure bomb survey can save the operators hundreds of dollars in initial equipment as well as increasing the efficiency of the installation. An example would be spacing the upper unloading valves based on available injection pressure when the static fluid level was several thousand feet below the surface. This is not only costly but sacrifices injection pressure for the operating valve.

2. The well should be conditioned prior to running the valves if mud or abrasive fluids have been used to kill the well. An operator would not use a rod pump to remove mud from the casing annulus. Many wells have been successfully cleaned up using flow valves, but the procedure is not recommended.

3. The opening pressures of the valves which will be used for unloading only should be set as high as possible when limited injection pressure is available. The tubing effect for opening these valves should be utilized to assure maximum injection pressure for the operating valve.

4. The wellhead tubing back pressure should be minimized by streamlining the wellhead connection, providing adequate flow line size, and maintaining minimum trap pressure at the battery. Low tubing pressures are necessary for efficient

gas lift operation.

5. For continuous flow the closing pressure of the operating valve should not exceed the flowing tubing pressure opposite the valve. This permits a minimum pressure differential across the valve and minimum gas passage with proper surface pressure regulation.

6. In deep or inaccessible wells, wire line retrievable flow valves should be used. Retrievable valves reduce valve replacement time. In many retrievable valve installations dummies are run in the lower mandrels and flow valves are installed in the upper mandrels for present gas lift requirements. As the bottom hole pressure declines the dummies and valves are interchanged to provide maximum pressure for the deeper lifting.

The following considerations aid in maintaining efficient operation after initial installation:

1. The installation of 2-pen pressure recorders on each well to record the daily wellhead tubing and casing injection pressures. This small investment will record the valve operation and reflect immediately any malfunction, change in producing characteristics of the well, or unknown fluctuation in available injection pressure.

2. The number of injection cycles per day and duration of gas injection for intermitting wells and the injection pressure for continuous flow wells should be changed until the most efficient gas lift operation is determined. Too many gas lift installations are not changed after the well is kicked off and has apparently stabilized. Since the producing characteristics change as the reservoir declines, the surface gas lift control should be adjusted accordingly.

In conclusion, flow valves are necessary for gas lifting most wells with nominal injection pressures because valves permit: unloading the well, changing of the point of gas injection for fluctuating bottom hole pressure, metering of the gas, prevention of excessive bleed-down between injections, utilization of gas volume in casing annulus, and the prevention of cutting holes in tubing or casing.

Gas lift methods are applicable to deep wells and crooked or directional holes and can be employed to lift high volumes of fluid and fluid containing abrasive materials, such as sand. The initial equipment cost is generally less than for other forms of artificial lift. The same gas lift installation can be designed for lifting from several hundred barrels down to a few barrels per day. The flexibility of gas lift has been improved further with the introduction of wire line retrievable valves which reduce valve replacement time and maintenance costs.

Gas lift is not possible unless gas is available. Field or well conditions that may favor other forms of artificial lift are: high acre spacing of wells, wells produced with vacuum on casing annulus, and very shallow low productivity wells with no pump problems and electricity available for pumping.

MR. ZABA

Thank you, Mr. Winkler. Now, the last, but by no means the least, of course, is the submerged electrical centrifical pump, commonly known as the Reda Pump, and Mr. Jerry F. Boutwell of Reda Pump Company of Bartlesville, will tell us about it.

MR. BOUTWELL

I am glad that we saved for the last the type of equipment that offers most promise for the future. A submersible unit, as it is used today, is an assembly that consists of a multistage centrifical pump and submersible motor, all suspended beneath well fluid on the tubing. Electric cable is clamped to the tubing at intervals for support and extends from the motor terminals to the power supply on the surface. It is primarily a high capacity pump that has three general types of applications.

The first is an oil well installation in prolific water drive areas, where it is profitable to produce much greater volumes of fluid than could be feasibly handled with some other types of equipment. The second is another high capacity application in water to flood wells where it is necessary to produce a substantial volume of water for operation of a flood or pressure maintenance project. The third is a relatively new field with us - an oil well installation but of a slightly lower capacity where the selection of a submersible unit is based on installation costs and operating expense - slightly lower capacity than the first I mentioned.

The first listed application is the oldest one. In many fields in Kansas and Oklahoma, where our first installations were made, wells have been operated with submersible pumps for as long as twenty years, pumping two to twenty times the volume of fluid that could be handled with some other types of equipment. The volume of fluid that can be handled in an oil well installation with a submersible type unit is determined by the casing diameter and the depth from which the fluid must be lifted. In 5 1/2 inch casing, the volume limitations would be from 250 up to 2500 barrels of fluid over a lift range of from 1800 to 8500 feet. The largest motor that can be installed in 5 1/2-in. casing is a 59 1/2 horsepower. In 7 inch pipe, the extra diameter makes it possible to increase the motor size to 250 horsepower, the volume up to about 7000 barrels of fluid, and the lift as deep as 8500 to 9500 feet. In 8 5/8 inch pipe, or larger, motor sizes up to 240 horsepower and fluid volumes up to 15,000 barrels a day are possible. There are many Arbuckle lime wells in Kansas where this volume of fluid - the volumes that I just mentioned - have been handled for the past twenty years, pumping less than two percent oil in total fluid. One well near Peabody has produced, since 1937, about 6000 barrels of fluid a day and the oil production is less than one-half of one percent.

Redrilling of old areas - old water drive areas - is common with the present crude price structure. A number of areas that were plugged out when the price of oil was half what it is today have been redrilled and reequipped with submersible units to handle the maximum capacity of the wells.

In the second type of installation, whenever it is necessary to drill a well for water supply to operate a flood or pressure maintenance program, it's generally important to get the water supply with the least investment in well and pumping equipment, and for that reason a submersible type unit is usually a satisfactory answer in that the qualities of small diameter, high head and high volume will permit a production of a maximum water volume from a single well.

The third type of installation, which in many oil wells is a troublesome category even with other types of pumping, is in wells making fluid volumes in the range of 300 to 1000 barrels a day. Those wells can be pumped, in many instances to maximum capacity, with some other type of equipment. However, in those cases where rod breaks, maintenance costs, low efficiency, and down time are serious factors, submersible type units have been successfully used to replace the other types of equipment. A good illustration of that type application is in a field in Navarro County, Texas, where about 50 wells have been reequipped with 30 horsepower submersible units, pumping from 800 to 1200 barrels of fluid a day. The operating costs prior to the installation of the submersible units were higher. Labor, pulling jobs from rod breaks to tubing wear, were excessive and the operation was marginally profitable. The operators are not producing any greater volume of fluid than they were with the other type of equipment. However, elimination of a lot of the down time has been responsible for an increase in production of 30 to 40 percent and the lifting costs are away down.

In considering a submersible pump installation for any of these different applications, the same factors have to be considered in each case. It is important to study well characteristics so that the right size pump may be selected. Productivity data should be determined by bottom hole pressure or sonic fluid level measuring devices, in order to select the right motor size, the right pump type, and the right setting depth. Factors such as gas-fluid ratio, solution gas pressure, reservoir characteristics, offset effect, and well communications should all be considered, and are factors that will influence the selection and location of a submersible unit.

After the proper selection of the equipment has been made, the operation is normally simple. A periodic check of load, power supply, and pump output should be made for a performance record. Any variation or fluctuation in these factors will show either pump wear or a surface or subsurface change that should be remedied.

To summarize, the submersible type unit has a limited application. It is a high capacity pump. The field of application is broader now than it once was due to development of slightly lower capacity units, to the improvement of efficiencies to the present 50 to 75 percent, and to improvements in some of the materials that we use. All of which means longer runs between pulling jobs -- which some years ago might have been 30 to 90 days between jobs, compared to the present average of two to three hundred days.

MR. ZABA

Thank you, very much, Mr. Boutwell. We will now open the meeting for questions.

FROM THE FLOOR

I have a question on the efficiencies of a Reda unit.

MR. BOUTWELL

In general the smaller the diameter of the pump the lower the efficiencies, so I will answer you in this way. Around 350 barrels a day, we have a pump efficiency of around 48 to 50 percent. Then for a medium capacity pump of around 2000 barrels a day, we would have pump efficiency of 60 to 65 percent. The higher capacity pumps up to 15,000 barrels - 70 to 75 percent. The overall efficiency that you asked about would be determined by the setting depth, cable losses, and motor sizes. So, those losses, if the unit is properly enginereed, will range from - I'd say - 5 to 20 percent. So your overall efficiency would be reduced by that amount, depending on your motor size and setting depth.

MR. ZABA

Does that answer your question? Does anyone else have any questions?

MR. McGOVERN

I have a question for Mr. Boutwell with Reda Pump Company. My name is McGovern with Phillips Petroleum in Hobbs. What is the deepest installation at present, in 5 1/2 inch casing for a Reda pump?

MR. BOUTWELL

I believe, as far as I know, in 5 1/2 inch, around 6500 feet is the deepest installation.

MR. McGOVERN

Would you say that is as deep as you can go in 5 1/2 inch casing?

MR. BOUTWELL

Yes, it is; the motor size is the limitation there. Fifty-nine and a half horsepower is the largest rating, and about the smallest pump size that we would recommend would be around 350 to 500 barrels a day. So, 6000 to 7000 feet would be the depth limitation because of the pump size - motor size limit.

MR. McGOVERN

Do I understand you correctly. You can pump approximately 300 to 500 barrels per day at that depth?

MR. BOUTWELL

That's right. About 500 to 600 - in that range.

MR. VASICEK

My name is Vic Vasicek with Cherry brothers. I would like to point this question to Mr. Ralph of Kobe. If you had a 5500 foot producing lease, say with two wells on it, would you recommend a Kobe installation on it. What I am referring to is the initial cost. Would it be economical in comparison with the rod type?

MR. RALPH

Can you give me a little more detail. How much production are we talking about?

MR. VASICEK

Say 200 barrels a day.

MR. RALPH

Total

MR. VASICEK

Total fluid.

MR. RALPH

Generally, I would say you are getting into an area there where it probably should be investigated. I think you might be at a point where it could be done. Now, that would require a smaller surface unit. It could easily be done with a 12 1/2 horsepower surface unit, which is a smaller size we make. I think the power oil tank could be smaller, and so forth. You are in an area in which, I think, we would have to sharpen a pencil to find out what you should do.

MR. VASICEK

Well, I would like to find out also - Say you drill a wildcat, where you have one well, possibly two at the most, and you have to put that first well on a pump say. Would you recommend just jumping right out, just for one well, and put in a Kobe installation.

MR. RALPH

Well, of course again, if you will qualify that on the basis of initial cost --

MR. VASICEK

That's what I mean. On initial cost.

MR. RALPH

All right. Generally, the first well on the lease, if you are talking again at shallow depth -

MR. VASICEK

I mean average - 5500 and so on.

MR. RALPH

Generally, you can put in a sucker rod pump cheaper than you can Kobe under those conditions.

MR. VASICEK

In other words, what you are saying is that possibly - say a four or five well minimum might be the best -

MR. RALPH

I think you had better start looking at it at two wells.

MR. ZABA

I believe there was another gentleman over there.

MR. MITCHELL

Mr. Boutwell with Reda, in his discussion pointed out that he was doing some water injection work from the well bore with his pump. I am Mitchell with Sinclair at Midland, I would like to have a little more data on that particular phase of your work.

MR. BOUTWELL

There are not many installations where Reda units are used for that purpose, that is, used for an injection pump. It is worth considering sometimes in the pilot stage of a flood just to save some initial equipment investment cost. However, if the flood is expanded and the operation is of any size, a surface centrifical or some other type pump can be used for injection pressures at much higher efficiencies than are available with a smaller diameter Reda.

MR. ZABA

Thank you very much. I wonder if anyone else has any questions.

MR. LAHMAN

Mr. Zaba, I would like to clear up some matters of early day costs of operating Reda pumps. I have been with Reda for 16 years, and about 10 or 12 years ago, before Jerry Boutwell's time, the price of crude was about a dollar or a dollar and a quarter a barrel. We did have mechanical difficulties due to design, which have been subsequently corrected, and just to show you the picture, as a matter of cost on today's oil market, for example in the Wilson Creek Field in Colorado, we are handling 4000 barrels of fluid per day for 800 barrels of oil, with about 24 barrels of oil operating cost overall. That is with 150 horsepower equipment.

MR. ZABA

Thank you very much, Mr. Lahman. No other questions? I thought that we had a real wonderful presentation of four methods of artificially lifting of wells, excellent discussion, very good questions. As far as I am concerned, I think that we should feel very lucky that we have four methods and not one, because there is no such thing as a universal method of artificial lifting, in that there will always be places where one will do better than the other. I think that we should be particularly thankful for the amount of work that has been done on each one of these four methods, to bring it to the state of efficiency that we have it now. Now I have been around for a long time, and I remember very well the time when gas lift was considered an intermediate method of production between the flowing and pumping life of the well. Then came the pressure operated valves, and we have now gas lift as a completely self-contained method of production. You can deplete to the economic limit. I remember very well when Kobe first came in, about 1930 or 31, and you wouldn't think of lifting very large volumes of water with a Kobe. We have installations now in West Texas lifting 1200 barrels of fluid a day out of 8000 feet with Kobe pumps. I remember where 6000 or 7000 foot sucker rod pumping was deep pumping. We pump now at 12,000 feet. I remember, in 1949, when we equipped a well, Garner No. 3, (I don't forget that name), we put a Reda pump in it, and we were hoping for the best, I'll be darn that thing is still producing. That was in 1949, and that well should have been abandoned in 1948. So, a tremendous amount of work has been done by the manufacturers.

But there is still another phase. It is not enough to design a proper method, to select and size the equipment properly. It's a question of going a step further and watching it in operation. I happened to have a talk here at the Short Course on "Lease Automatic Custody Transfer", and I brought out the point that the pumper will have more time with automation to devote to more efficient operation of artificial lift installations.

So, I think we have made a wonderful start, we have four methods, I think that each one of them, under certain conditions is the best. We should continue using them intelligently. I don't think that we even need that fifth one that somebody mentioned that may be coming. Well, if there are no other questions, I would like to thank very much the members of the panel for being here.

MR. W. L. DUCKER

In behalf of Texas Technological College, and in behalf of the Department of Petroleum Engineering, and in behalf of the West Texas Oil Lifting Short Course, I especially want to thank these gentlemen for their contribution here to what has been, I believe, one of the high points of the program. We are indebted to each of you for your part in it, and I want to thank the rest of you for coming and hope to see you another year.