ARTIFICIAL LIFT - WHICH METHOD BEST FITS YOUR NEEDS?

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One of the first things Colonel Drake did at his Titusville location on Monday morning, August 29, 1859, was rig a hand pump to a 20-ft piece of pipe, attach the handle to his rig's walking beam, and put the world's first commercial oil well on artificial lift.

One way or another, we've been doing it ever since. Not wisely, always, but often. Of the 526,855 crude oil wells on production in the U.S. at the end of 1979, says the Independent Petroleum Association of America, 93.4 percent (more than 492,000 wells) were on some form of artificial lift.

In the course of 120 years between 1859's one assisted well and 1979's 492,000, we have improved tremendously on the rudimentary equipment and technology Colonel Drake applied. We have not always, however, used advanced technology to full advantage.

The truth of the matter is that we've blown some mighty big bucks on initial installations and subsequent maintenance/repair/replacement of artificial lift equipment that was wrong for the well to which it was applied. Not always, by any means, but far too often, we've selected artificial lift systems, product types within systems, and/or models and sizes within product types that were less than best for the wells or reservoirs with which we were concerned.

If we're to meet soaring energy needs - particularly if we'd prefer to do so at a profit - poor selection of the aids to our oilers is a luxury we can ill afford. Awareness of the need for better matching of equipment to the job and efforts to achieve better selection have become increasingly apparent since the Mid-East embargo of 1973. But it's an uphill battle that hasn't yet been won.

It's an uphill battle, in part, at least, because of the modern petroleum industry's generation gap.

Proper matching of artificial lift equipment and technology to the specific problems of specific wells and reservoirs at acceptable cost is a rather sophisticated engineering exercise. Despite our current influx of engineering talent, people fully qualified to design and oversee the best possible artificial lift installations are in short supply. And those who are fully qualified very likely have other demands on their time.

We've only recently emerged from a 10- or 12-year period during which movement of personnel was out of, not into, the petroleum industry. The wellwise technical people who stayed with the industry through the lean years of the late Fifties and the Sixties tended to move upward into management positions where they now have little time for the nitty-gritty of artificial lift design.

At the other end of the corporate ladder are the in-coming young engineers who, however intelligent and well educated they may be, lack the hands-on wellsite experience of their elders.

Between our corporate top frogs and polliwogs, there simply isn't much. For the people we should have attracted, trained and seasoned during those lean years went instead into aerospace and other industries, leaving a void between the well-wise manager and the relatively inexperienced young engineer to whom he must delegate the pencilwork of artificial lift design.

The temptation, of course, is to turn system recommendations and equipment specifications over to a supplier of artificial lift equipment. But vendors, too, took a walloping during the Fifties and Sixties and have technical staff problems not greatly unlike those of the oil companies.

That we're doing as well as we are is a tribute to our well-wise managers, the hard work of our newcomers, and the training programs - in-house and otherwise - that are closing the gap between them.

There is a demonstrable correlation between artificial lift training schools and improved artificial lift field results, not because those of us who teach artificial lift are particularly brilliant and not because we impart knowledge available nowhere else, but because we present in organized form the concepts and hardware that have been proven at the wellsite. All or most of what we teach, our students would learn, in time, the hard way. We try to shorten their learning curve and hopefully, we spare the students and their employers at least some of the mistakes that those before them have made.

What we're concerned with is the transport of fluid from the wellbore to the surface at a satisfactory rate and acceptable cost. The happiest solution, of course, is the reservoir power of the flowing well and there was a time, back in the 1860's, when oilmen completed a well that would flow and promptly abandoned wells that wouldn't.

For today's wells that won't flow at acceptable rates, whether initially or at some later time in their productive lives, there are several broad avenues of assistance. The most common of these avenues are the artificial lift systems and the most common artificial lift systems are sucker rod pumping, hydraulic pumping, electrical submersible pumping, and gas lift.

The owner of a well that needs help, then must first decide what kind of help to provide. Should he install gas lift equipment or a pump? If the latter, what type of pump? This is not a decision to which he is eternally anchored. Reservoir conditions change with the passing years and the well that is an ideal candidate for gas lift today may someday be just right for a hydraulic or sucker rod pump.

Non-reservoir changes can also alter conditions. A great many of the artificial lift systems in service today were installed during an era of restricted production and depressed oil prices. Are they or are they not adaptable to the requirements of the Eighties?

If we are to realize maximum benefit from artificial lift, we must look - probably more than once during the life of the well - at four groups of factors: those related to the lease, to the well, to the reservoir, and to the equipment itself.

LEASE FACTORS

Are we designing an assistance system for one well or for a group of wells? A system that might be prohibitively expensive for a single well may prove the most economical solution for a group of wells closely enough spaced to share some of the system's components. A central power fluid facility, for instance, might serve hydraulic pumps in several wells economically where a power fluid facility serving a single well might be too costly.

What about the surface terrain? Are we over water? In a swamp? On a mountain? How much space do we have for the accouterments of artificial lift? How far, over what obstacles, through what sized flowline must we move the crude after it reaches the surface and what effect will these conditions have on wellhead pressure and, thus, production rates?

What type of power is available at what cost? What type of lifting system will the available power best serve? It's unlikely that we'll opt for electric submersible pumps where the cost of electricity is prohibitive or for gas lift where there is no high pressure gas available, or compression costs are excessive, or large volume purchases of makeup gas are necessary.

What degree of automation do we need? If we want a highly automated installation, it's virtually imperative that our equipment be compatible with electric power.

Do we plan to continue using existing battery and treating equipment? If so, for instance, we may want to avoid an intermittent gas lift system that would repeatedly slug and briefly overload facilities that are more than adequate to handle the well's output if it moves continuously rather than in surges.

Is artificial lift equipment of some type already in service nearby? If so, it probably is familiar to our people. Repairs and service procedures probably have been established. Presumable, the artificial lift equipment is compatible with battery and treating facilities in place. There may be economies in extension of what's already there to cover an additional well or group of wells.

What's our manpower situation? Will people be reasonably available at all times to operate the equipment? To service and repair it? How much experience have they had with what types of lifting systems? What additional training will they require?

WELL AND RESERVOIR FACTORS

There are three things we absolutely must know about a well if we're to design an artificial lift system for it. We must know the producing depth, the amount of fluid that will move from the formation to the wellbore, and specifications of the conduits into which we must run our subsurface equipment and through which we will move fluids to the surface. Diameters of casing, liners and tubing establish the maximum diameters of our downhole equipment. Well depth, production tube diameter, and incoming fluid volumes establish the loads that our equipment must lift without failing.

Beyond those three basics are a number of other determinations that will help us better tailor the lift system to the well. Some relate principally to the well itself, others principally to the producing formation, but they are so inter-related that they'll be considered together here.

Is the hole straight or deviated? In the latter case - and almost certainly if the deviation exceeds 30 deg, we may want to consider something other than sucker rod pumping.

Are we working with a single or multiple completion? If it is a multizone well, how many zones need help? Will one type of lift be best for all zones or do we need two systems within a single borehole?

Are we producing through perforations or from open hole? Is the producing interval long or short?

We know we want to reduce borehole pressure opposite the pay so that formation fluids can enter. To what point shall we reduce bottomhole pressure, what fluid inflow will that achieve, and what will it take to move that fluid to the surface? If we want maximum reduction of borehole pressure opposite the pay, we want a pumping system rather than gas lift and we probably want a sucker rod pump if hole angle permits and weight of the fluid column won't exceed the strength of our rods. If angle and weight make the rod pump a poor choice, we probably will be happy with a hydraulic or electric submersible pump.

Of the fluid we're to produce, what percentage will be oil and what percentage will be water? What's the API gravity of the oil? The specific gravity of the water? We need to know if we're to calculate the loads to be lifted. If we're dealing with heavy, viscous oil, we may want to give serious thought to a hydraulic pumping system that will permit us to co-mingle a thin, light power fluid with the viscous formation fluid to get a more manageable mixture.

What gas-liquid ratio are we to handle? Of all the systems available, only gas lift actually benefits from a high gas-to-liquids ratio. All other systems are adversely affected unless solutions to the gas problem are designed into the installation.

What's our bubble point? Will we be able to maintain fluid pressures somewhere above the bubble point or will we be dealing with the break-out of free gas?

Will our well produce sand or other fine solids? Can we screen off the solids or will we, in the process, screen off liquids also? If we must produce sand or other abrasives, which system would they damage least? Gas lift, of course, if that's a viable system in other respects, for no sand should ever pass through properly functioning gas lift valves.

What about paraffin? As temperature of surface-bound fluids drops, paraffin precipitates and sticks to anything in the hole.

Are our well fluids corrosive? If so, what countermeasures must we take?

High bottomhole temperatures can severely affect electric submersible pumps, past which the fluids move soon after leaving the formation. Nor are elevated temperatures confined to the bottom of the hole. Production of hot fluids also raises surface temperatures, sometimes to levels that adversely affect surface equipment unless the design took those temperatures into consideration.

Most wells on artificial lift are or will be involved in secondary and, perhaps tertiary recovery programs. Will equipment raising X-bbl of fluid, 90 percent oil, today be adequate to raise 10X-bbl of fluid, 2 percent oil, sometime in the future? If not, will upgrading of the installed system be possible and practical? What are or will be the compatibility of injected and formation fluids and their effects on the artificial lift equipment?

Will it be operationally and legally possible and practical to co-mingle production from two or more reservoirs produced through one borehole or production from two or more separate wells?

EQUIPMENT PARAMETERS

Also critical to selection of an artificial lift system are availability, durability, flexibility, and relative economy of the hardware itself.

Do we already have on hand surplus equipment applicable to one of the artificial lift systems? What's the relative availability of any other equipment we need?

Under our operating conditions, what useful life can we expect for components of the various systems available? Will we have trouble getting remedial rigs or other service equipment? Are repairs and replacements available nearby?

Can the system we envision be adapted to changing conditions at acceptable cost? Presumably, we will be handling increasing volumes of fluid as time goes on in order to produce enough oil to warrant continued production of the well. Will the installed equipment meet increased requirements? If not, what changes will be required and how much will those changes cost?

Under the conditions that now exist and those which we anticipate, what would be the relative costs of the available system over the life of our well or wells? And with which costs are we most concerned? Is the lower initial installation cost of System "A" more important to us than the later adaptivity advantages of System "B" or the savings we think System "C" could achieve during the productive life of the well?

What will be the salvage value - to us or to someone else - when the equipment we install today is ready for removal? It's quite likely that most of our wells will require two sets of artificial lift equipment, one during the primary recovery phase and another during the secondary phase. Will some or most of the equipment we install today be useful in the later installation? Can we transfer it to another well? Can we sell it to somebody else after it has served our purposes?

Conditions that exist in the formation, in the well, on the lease and in the equipment market tend to eliminate, in most cases, one or two or more of the available artificial lift systems, leaving one - or sometimes two - approaches that seem best suited to the job at hand.

It's no happenstance that, 88 times out of 100, the selection will be ....

....THE SUCKER ROD PUMP. The various configurations of this system are virtually uncontested in the low-volume, shallow-to-medium-depth oil well market and there have been numerous installations in wells in the 12,000-ft range so long as lifting loads do not exceed the strength of the rods. While the fine points of system design and application can become very complex, the sucker rod pump, itself, is a comparatively simple machine that can be operated and maintained by people with relatively little training. The surface unit is an extremely durable device, running for extended periods at minimum cost despite neglect and abuse. When powered by electric motors, it is readily adaptable to automation. A tremendous variety of surface and subsurface component sizes and capacities gives the sucker rod pump a wide range of application and the hardware is backed by a mass of design and performance data with which most people involved with artificial lift are familiar or with which they can quickly become familiar at the various sucker rod pumping schools. The equipment is readily applicable to multiple completions where one side flows and the other pumps; where both sides pump, using either head-to-head surface units or stacked heads on a single surface unit; or where different systems are applied to one wellbore - perhaps gas lift on one side, a sucker rod pump on the other. The system presents no obstacles to treatment of the well for corrosion or scaling problems and, in most cases, it surpasses any other system in lowering borehole pressure opposite the pay zone. The salvage value of surface components is extremely high and oil fields abound in assemblies that have been nodding over one well after another for 40 years or more. In the great majority of wells to date, the sucker rod pump has proven to be the most economical way to go.

But it is not the answer to every well. For deep, high-volume producers - particularly if they make measureable quantities of gas - the better answer may be...

....GAS LIFT. If high pressure gas is available or if limited compression is required, this system could well be the least expensive to install. It will raise a lot of fluid from substantial depth and gas from the formation will help rather than hinder its work. Wireline retrievable valves and mandrels cut the downtime and expense of remedial operations. The effects of abrasive solids are minimal since they don't pass through the gas lift valves and the system lends itself to control of paraffin by plunger lift or the cutting methods employed in flowing wells.

Two gas lift systems serving separate pays in a single borehole can use a common gas source and extension of an existing gas lift system to an additional well or wells is relatively easy. Injection of gas into the wellbore to aerate and help lift the fluid column limits the formation-to-borehole pressure differential that can be maintained. But intermittent (rather than continuous) injection provides intervals during which fluids can enter the hole and applicability of the system is often further enhanced by a variation known as chamber lift - use of the tubing-casing annulus as a chamber in which well fluids are collected and from which they are periodically forced into the tubing by applied gas pressure.

Incorporating some of the advantages of gas lift (though not its tolerance of free gas) as well as many of sucker rod pumping's advantages is ....

....THE HYDRAULIC PUMP. Like gas lift, the hydraulic pump offers cost advantages at the time of installation. It requires no sucker rods or surface equipment to reciprocate those rods. It does require power fluid pressuring facilities, but the per-well investment can be greatly reduced if a central power fluid system serves several wells. Since there are no sucker rods to rub against a tubing wall or fatigue in doglegs, hydraulic pumps are much more applicable than rod pumps to deviated holes. "Free" type hydraulic pumps (those which can be pumped into and out of the hole and thus do not require the help of remedial rigs) are generally said to offer minimum operating and maintenance costs - a claim that may be questionable in some cases. When all produced gas must be passed through a casing free pump, for instance, maintenance frequencies and costs increase to levels that may offset savings achieved through ability to pump the assembly in and out. Freed from the limitations of sucker rod strength, the hydraulic pump can lift larger volumes from greater depths than can the rod pump - though no more than can be raised by gas lift or an electric submersible system. As an example, a hydraulic pump can lift 1000 bbl of fluid a day from 8000 ft, which is no mean accomplishment. The hydraulic pump is compatible with centralization of facilities and with automation. Among the many models and sizes available are pumps to handle virtually any fluid volume requirement and pumps readily can be changed with changing well conditions. A pump no longer applicable to a given well can be salvaged for use in another. As with gas lift, expansion of a hydraulic system to additional wells is relatively easy so long as it's within the limitations of the central power system. Surface readings at a well equipped with a hydraulic pump of known specifications can be interpreted to reveal much about what's happening downhole and in the reservoir. Corrosion inhibitors, paraffin solvents and other additives can be blended with the power fluid and moved throughout the system. And hydraulic pumps are highly adaptable to multiple completions, especially if the production can be co-mingled.

Often preferable to any of the alternatives for handling large volumes of fluid in wells of widely varying depth is ....

....THE ELECTRIC SUBMERSIBLE PUMP. Variable speed motors have greatly extended the range of fluid volumes a given submersible pump can handle and the system, as a result, is finding wider application. In the past, the tendency has been to size an electric submersible pump for a certain rate of production. Following a significant change in the required production rate, the only course was to pull the entire subsurface assembly and install a new motor, separator and pump sized for the new conditions. Now, many such changes can be accomodated by changes in motor speed. Producing depths involved tend to range from shallow to the far side of medium, the major constraint being the horsepower it is practical to pack into a tool that must be run, as a rule, in 5½-in. or 7-in. casing. That this power is appreciable is apparent in the fact that there are electric submersibles lifting 400 or so bbl a day from below 12,000 ft. In shallow to medium holes, the submersible very likely will represent a lower installation cost than will a rod pump, but that advantage tends to fade away with increasing well depth because of power cable and other costs. The system is readily adaptable to automation and serves well in deviated holes as long as the pump, itself, is not in a deviated portion. One of the electric submersible's more interesting advantages is its ability to function, upright, as a producing pump or, inverted, as an injection pump.

Each of the principle artificial lift systems - rod pump, hydraulic pump, electric submersible pump, gas lift - has its advantages and disadvantages. Within each system are variations designed to maximize that system's advantages and overcome or minimize its disadvantages. Among variations on the hydraulic pump theme, for example, is the jet pump, essentially a Venturi tube, which often can provide the advantages of hydraulic pumping to wells making too much gas for conventional equipment.

Once we have determined which artificial lift system best fits our requirements, then, we can further refine our selection by studying the variations available within that system.

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