Oilfield Submersible Pumps: Selection and Application for High-Volume Pumping

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INTRODUCTION

A typical submersible pumping installation, as shown in Fig. 1, is comprised of both subsurface and surface equipment. The subsurface equipment consists of an induction-type three-phase, 60-cycle electric motor, a multistage centrifugal pump, and a seal section which is attached to the motor for the purpose of sealing the motor against the entry of well fluids. The seal section also provides reservoir space for the motor oil which is continuously being circulated through the motor as it operates. A gas separator is usually required in oil-producing wells and is installed at the pump intake.

On the surface, one will normally find a switchboard (control panel), a special well-head assembly designed to accommodate both the tubing string and the three-conductor jacketed cable which is used to supply the motor with electricity and, generally, an electric transformer.

The proper use of a submersible pump requires a good design based on an engineering approach which takes into account the well and fluid conditions and emphasizes the value of accurate, reliable data. In designing a submersible pumping installation, one must be aware that the equipment he selects will not perform well on mere expectations or hope; "good numbers" for the well and fluid conditions are essential, and it behooves everyone charged with the selection of submersible equipment to avail himself of the best information attainable. This may take some time and, possibly, money, but where the submersible installation is being seriously considered, the time and money will be well spent. Proper design of a submersible pumping installation requires an engineering approach based on accurate data.

Pumping with a submersible pump is one of several methods employed for what is termed "high-volume lift." What may be high-volume is not entirely agreed upon, but, in considering a submersible pump for his needs, one usually must have a requirement of at least 500 BFPD. Submersible pumps are available for volumes up to 23,000 BFPD.

An oilfield submersible pump is used primarily for oil producing wells and water supply wells. Within the limits of these two uses, there are certain variations in the way a submersible pump may be applied to a particular fluid-producing problem. As a result of these variations, submersible pumping offers a significant flexibility.

The idea has been advanced that the present emphasis on secondary recovery will open a broad new horizon for submersible-type high-volume pumping. In certain types of waterflood projects, this idea seems to have considerable merit. The reservoir engineer, waterflood project engineer, and equipment engineer would do well to investigate the economics of submersible pumping in light of anticipated flood performance and consequent lifting requirements throughout the life of the project.

EQUIPMENT DESIGN AND SELECTION

In designing and selecting the equipment for a submersible unit, one must take into consideration several factors. These factors are:

- (1) Volume desired
- (2) Productivity index of the well
  - (a) Static and working fluid levels or
  - (b) Static and flowing bottomhole pressures
- (3) Casing size and tubing size
- (4) Well and fluid conditions
  - (a) Corrosiveness
  - (b) Free solid content—sand, etc.
  - (c) Gas present (gas-liquid ratio)
  - (d) Viscosity of fluid
    - 1) Oil
    - 2) Oil-water mixture
  - (e) Ambient temperature
  - (f) Specific gravity of fluid

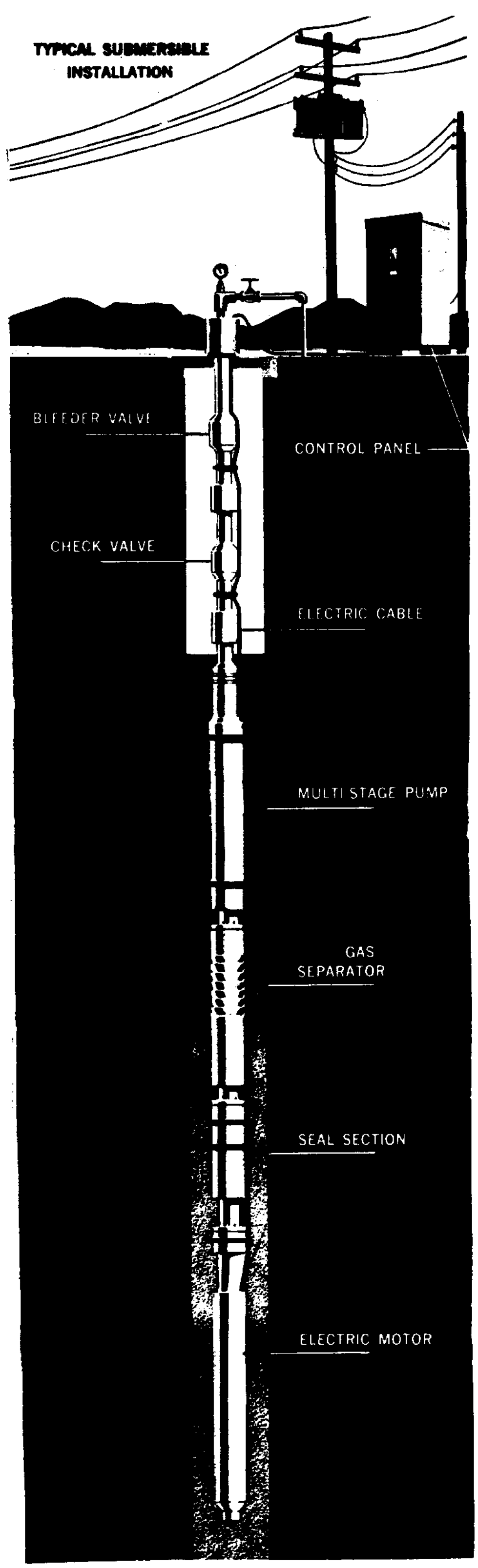


Fig. 1

TYPICAL SUBMERSIBLE

INSTALLATION

Certain of the above factors may be known or easily determined; some, however, are variables and require some investigation before one may arrive at a well-engineered pump selection. The volume desired is usually no problem; practically everyone has some number representing his fluid requirements. Whether or not this is a realistic figure depends largely upon the capacity of the well to produce. Consequently, it is quite necessary to know the productivity index of the well. Surprisingly, very few people know just what their wells' P.I.'s are. As a result, most pump designs are based on "reasonable" estimates which may be fairly close to the actual P.I. in a number of instances, but, in too many cases, this estimate is oceans apart from the true figure.

The casing and tubing size are practically always known, but well and fluid conditions are often given as mere guesses. In many cases, such things as fluid corrosiveness, gas-liquid ratio, free solids content, bottomhole temperature, and the specific gravity of the liquid may, at least, be qualitatively ascertained and can be taken into account in the selection of the equipment making up the submersible installation. The viscosity of the fluid is practically never known. This, in certain cases, is unfortunate. But it's not surprising, because the viscosity of a fluid under the conditions existing at the pump intake is practically impossible to determine with any accuracy. Naturally, viscosity is not so much a matter of concern in water supply wells as it it with oil wells.

Example of Equipment Selection

Perhaps an example of equipment selection would best serve to illustrate the importance of good engineering based on reliable data. An example such as this is necessarily broken down into a step-by-step approach.

Assume that we have a producing well in a highly active, natural water drive reservoir. This well is cased with 7-in. casing and pumps through $2\frac{7}{8}$-in. tubing. The top of the perforations is at 2000 ft. The amount of oil being produced from this well has fairly well stabilized at 5 per cent of the total volume. The well is presently pumping 500 BFPD with a large beam pump. The working fluid level at this 500-BFPD rate is 1200 ft from the surface. The static fluid level is at 1000 ft. Thus, we have an indicated P. I. of 2.5 BPD/ft. It is desired to raise the oil production to a top calendar-day allowable of 75 BOPD.

It is reasonable to expect the P.I. of 2.5 BPD/ft to also apply to an increased rate of withdrawal. Furthermore, the oil percentage can safely be expected to remain at 5 per cent, although variations in the oil percentage do occur with higher pumping rates; often the percentage decreases, but increases are not uncommon.[1] From these conditions, we can readily see that, in order to raise the oil production from 25 BOPD to 75 BOPD, three times the total volume is required, or 1500 BFPD. Applying our P .I. of 2.5 BPD/ft, we can calculate a working fluid level of 1600 ft at 1500 BFPD. Theoretically, it could be possible to set the pump just below 1600 ft. But for practical reasons, such as possible variation in the P. I., temporary fluid level fluctuation, or subsequent drawdown in the fluid level, the pump should be submersed sufficiently below the anticipated working fluid level to guard against pump shutdown due to pump-off.

Suppose that 200 ft of submergence is desired; then, we have a pump setting depth of 1800 ft. The calculated lift remains 1600 ft. By referring to an appropriate friction loss chart, a friction drop of near 35 ft can be expected in the 1800 ft of 2⅞-in. tubing at a 1500 BPD rate. Suppose in this case we have a surface discharge pressure requirement of 50 psi in order to overcome flow line friction and elevation differences on the surface. The specific gravity of the fluid is 1.02; its gradient is, therefore, 0.44 psi/ft. This means that the 50 psi discharge will add 115 ft of head to the total head required, that being 1750 ft (1600 ft lift plus 35 ft friction loss plus 115 ft surface discharge pressure).

Subsurface Equipment Selection

Now, which pump type shall be selected to deliver 1500 BFPD? This can be determined by referring to the performance curves for the various submersible pumps available. Here, obviously, we want a pump which is most efficient at 1500 BFPD. A pump type whose peak efficiency falls at or very near to this volume should be selected (Fig. 2). We see that, in this case, there is a choice between two pump types which we shall refer to as G-48 and I-42. (These represent a common method of designating submersible pump types. The letter usually has no partciular significance; the number represents pumping rate which, in this instance, is gallons per minute. With one manufacturer, this number means hundreds of barrels per day.) Usually, we are not given such a choice, but it happens that in this volume range there are two different series (diameters) of pumps which can be used. The G-48 which can be used in 5½-in. casing or larger and the I-42 which is sized for 7-in. casing or larger are both able to fit inside the 7-in. casing.

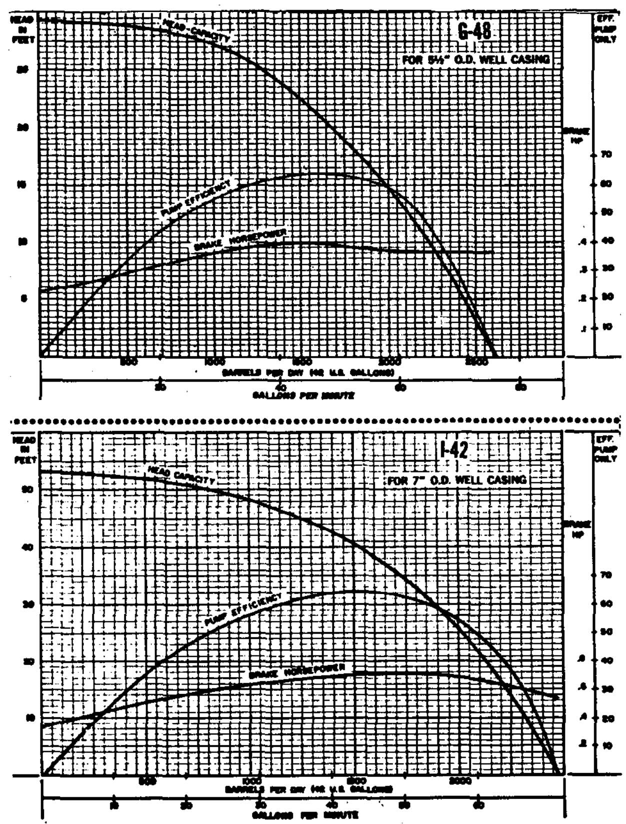


Fig. 2

PUMP PERFORMANCE CURVES FOR SUBMERSIBLE PUMPS OF SIMILAR VOLUME CAPACITY AND EFFICIENCY

The G-48 Capacity-Head (Q-H) curve indicates that, at 1500 BPD, this pump has a head capability of 22.5 ft per stage. By dividing the total head of 1750 ft by 22.5 ft/stage, we get 77.9 stages or 78 stages required for the G-48. Similarly, we use a figure of 40.5 ft/stage for the I-42 and arrive at 43.2 or 44 stages. If a 78-stage G-48 were significantly cheaper than a 44-stage I-42, or vice versa, we could make a selection at this point based on the initial cost of the pump. However, there is no appreciable price difference between these two pumps. Nor is there enough difference in pump efficiencies to lead us to a conclusion at this point (the I-42 is 64.5 per cent efficient while the G-48's efficiency is 63.8 per cent). Therefore, we must direct our attention to another consideration, and that is the size of the motor needed to drive each pump.

The Brake Horsepower curve (Fig. 2) shows that each stage of the G-48 requires 0.40 HP at 1500 BPD. This means that we have a HP requirement for this pump of close to 31.2. A 30 HP motor can readily handle this load. The I-42 requires 0.72 brake horsepower per stage or 31.7 total HP which is very close to that needed for the 78 G-48. Again, a 30 HP motor can be safely used. Therefore, there is no difference in initial cost of the motor. And, since there is not a substantial gap between pump prices, still other factors should be considered in determining which pump to select.

Recall that well and fluid conditions were mentioned as being important in equipment selection. Specifically, gas and the viscosity of the fluid affect the efficiency of the pump. Gas, of course, will decrease the volumetric efficiency of the pump, and may affect the Head-Capacity characteristics of the stages. Certain oils or oil-water mixtures are usualy manifest in higher viscosities which could appreciably affect the Q-H curve.

The Q-H curves of the G-48 and the I-42 are somewhat different in that the G-48 curve is fairly "steep" (vertical) while the I-42 curve is more "flat" (horizontal). (Fig. 2). The difference is meaningful for our purposes. Say, for example, that due to gas or fluid viscosity or both, we will suffer a certain loss in head capability. The amount of this loss is something which cannot be reliably determined beforehand and is usually evident only after the pump has been installed. Nevertheless, it can be seen that, whatever the loss in head, with the "steep" curve pump (G-48) that loss will not reduce the volume obtained so much as will a proportionate loss in head by the "flat" curve pump (I-42). Therefore, if gas or fluid viscosity may be a problem, we should select the "steep" curve pump type, here, the G-48.

Next, we select a seal section of proper size (series) in order to provide a means of sealing the motor from the well fluids.

We now have made our decision on the downhole equipment. A 30 HP, 78-stage G-48 run with 2⅞-in. tubing will be set at 1800 ft. This being a producing-well installation, we should also install a gas separator with the pump. This downhole gas separator will be very helpful in reducing the adverse effects of any gas being produced with the liquids.

Cable Selection

Our next consideration is the cable to be used in order to supply the motor with electricity. It is advisable to make the cable long enough to reach the motor setting depth and provide enough above the ground to facilitate surface connections. Usually, 100 ft of cable will take care of the surface hookup. Thus, we require 1900 ft of cable. But what size should the cable be?

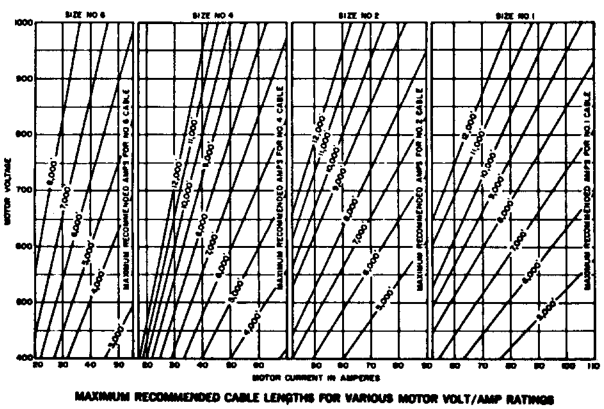


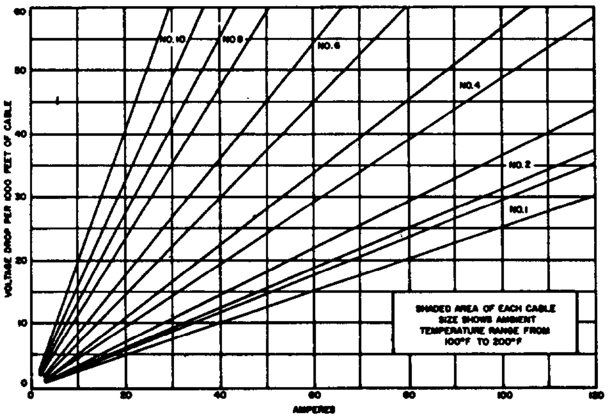
Fig. 3

MAXIMUM RECOMMENDED CABLE LENGTHS FOR

VARIOUS MOTOR VOLT/AMP RATINGS

In order to answer this question, we should first know the rating of the motor in terms of voltage and amperage. Let's assume that we have 30-HP motors available in two different volt-amp ratings, i.e. 730/37 and 440/58. (Such choice in motor ratings is not available in all motors. Some motors have only one rating.) By referring to the charts for cable lengths recommended for various motor ratings (Fig. 3), we can see that if the 730-volt, 37-amp motor is selected we can use size #6 cable, whereas with the 440/58 motor, we will exceed the limits for size #6 cable and will have to use the next larger cable, size #4. It so happens that we have no space limitations here regarding the size of cable that can be run inside this 7-in. casing with the 2⅞-in. tubing. However, it should be remembered that there are instances where the space between the outside of the tubing string and the inside of the casing is small, and thereby imposes a limit on the size of tubing or cable which can be used.

Next, a flat cable to connect the round cable to the motor is specified. This is selected on the basis of motor size and the length needed to span the distance from the top of the pump to the motor head.



VOLTAGE DROP PER 1,000 FEET OF CABLE—CABLE SIZES FROM #1 TO #10

Fig. 4

VOLTAGE DROP PER 1,000 FEET OF CABLE

CABLE SIZES FROM #1 TO #10

We should next consider the primary voltage available at the well site. If a 440/480-volt system is the primary source, it is easy to see that we could, by using the 440/58 motor with size #4 cable, supply the motor without the use of a transformer. The required surface voltage is determined by adding the motor voltage (440V) to the voltage loss in the 1900 ft of #4 cable (about 53 volts, obtained in Fig. 4). This 493-volt requirement can usually be reached by a 440/480-volt system without transformation. Should the primary system be of high voltage, e.g. 7200/12,470, or 13,200, we will then need a step-down transformer. In this case, we would gain by selecting the 730/37 motor and using #6 cable in order to reduce cable cost. Looking at Fig. 4, we can calculate a voltage drop of near 52 volts which, when added to the 730 nameplate volts, brings the required surface voltage to 782. Required surface voltage is usually designated by an appropriate ten-volt range, which, in this example, would be 780 to 790 volts. The step-down transformer would necessarily have a secondary voltage tap range within which this required surface voltage would fall. Quite often, it will be necessary to step up a 440/480-volt system to a higher voltage than can be accommodated by the primary system. Transformers are available for this type of transformation also.

Surface Equipment Selection

For the purposes of this example, we shall assume that the primary voltage is 7200 volts. We must, therefore, choose a transformer to step this primary voltage down to the required surface voltage of 780 to 790 volts. Normally, a good rule for transformer selection is that there should be one KVA Capacity for each motor horsepower. For this 30 HP motor, we can specify a bank of three single-phase 10 KVA transformers with an appropriate secondary tap range. These three single-phase transformers will give a 30 KVA capacity. In those instances where a 440/480-volt system must be stepped up, an "Autotransformer" is employed, this being a three-phase transformer contained in a single housing.

Next, we must investigate the need for a switchboard. In all cases, a control panel of some sort will be necessary in order to operate and control the submersible pump. Ordinarily, the basic components installed in a switchboard are a disconnect switch, a starter button with a selector switch for automatic or manual operation, an overload protection device, and a ground rod, along with the proper contactors, coils and control transformers which are part of the switchboard power or control circuitry. Generally included are other switchboard accessories which are very important for safety and convenience. There are: undercurrent shutdown devices, automatic restart with timing device, recording ammeter, lightning arresters, and liquid level or pressure shutdown switches. Some manufacturers also offer downhole-pressure recording devices. Just which of these switchboard accessories are to be selected will depend a great deal on the operator's requirements or preference. Where there is some uncertainty regarding the well's capabilities or the nature of the fluid, it is wise to include as many switchboard accessories as is practicable, especially those accessories which provide means of monitoring (recording ammeter) and controlling (undercurrent shutdown, auto restart) the unit's operation.

For our purposes, we shall assume that this is our first such installation in a well of this nature and, thus, we want to know as much as possible about how the unit will operate under these well conditions. Consequently, in addition to the basic components, we specify an undercurrent shutdown, auto restart, recording ammeter, and a lightning arrester.

What about the voltage which the switchboard can handle? Switchboards are available to handle any required surface voltage. Here we have a required surface voltage of 780 to 790 volts stepped down from a 7200-volt primary. Our switchboard voltage should accommodate the low voltage. This is 780 to 790 volts in our example, but it could be in the 440-480 volt range when a 440/480 primary system is to be stepped up. We, therefore, select an appropriate switchboard capable of handling up to, say, 880 volts. It should be mentioned here that the switchboard must also be rated for the horsepower of the motor in addition to the voltage rating. This means that in our selection we must be certain that the switchboard also carries a sufficiently high HP capability.

We now have but to select the proper size wellhead and our submersible unit will be complete. The casinghead or tubing head will be one which will make up on the 7-in. production string and in which the 2⅞-in. tubing can be hung and packed off along with the #6 cable.

Looking back over this submersible unit, we see that we have specified a 30 HP, 730 volt, 30 amp motor, driving a 78-stage G-48 pump which should produce about 1500 BFPD against a total head of 1755 ft. We have included 1900 ft of #6 cable and a bank of three transformers with primary taps for a 7200-volt primary system and secondary taps to provide the required surface voltage of 780-790 volts. Our switchboard is sized to handle the 30 HP motor and the required surface voltage, and our wellhead assembly has been properly sized for 7-in. casing, 2⅞-in. tubing and #6 cable.

Influence of Well Conditions on Equipment Specifications

The material making up this equipment may be affected by the degree of corrosiveness of the well fluids. A corrosive fluid will require us to coat the housings of the motor, pump and seal sections with some appropriate corrosion-resisting coating. This can be either plastic or metal, the composition of the coating being determined by the severity and nature of the corrosion. Some operators go so far as to require the housings themselves to be built of corrosion-resistant metals such as various nickel alloys. However, this practice has been generally proven unnecessary since it is extremely expensive and suitable coatings have been developed which do the job almost as well and at considerably less expense. Such things as cable armoring and cable bands may necessarily be of monel in order to prevent the expensive deterioration of the cable string due to corrosion.

Internal corrosion can often be a problem, but this is not so much a matter of concern where the internal parts of the pump are built of such corrosion-resistant materials as Ni-resist and K-monel. Most manufacturers offer Ni-resist impellers and diffusers and K-monel shafting as part of their standard construction.

Temperature may be a problem. If the ambient temperature at the motor depth is high enough, that is, in the 200°F range, it is often wise to specify special, high temperature oil for the motor. Here again, it can be seen that accurate data pertaining to well conditions is helpful in achieving a properly engineered submersible design.

Another area where temperature should be considered is in cable selection. Basically two types of cable are available: a rubber-jacketed, metal-armored cable and a platsic-jacketed, non-armored cable. If the temperature around the cable exceeds 150°F, it is usually not advisable to use a plastic-jacketed cable due to possible softening and subsequent deformation of the jacketing. It should be pointed out, however, that where the temperature permits, the plastic-jacketed cable is ideally suited for corrosive fluid.

LIMITATIONS OF SUBMERSIBLE PUMPS

There are a number of factors which impose certain limitations on the operation of submersible pumps. Most of these limiting conditions are not absolute. That is, they do not entirely preclude the use of a submersible pump; rather, their presence should make one aware that the life of the pumping unit will not be as long as in the case of less severe conditions. For instance, high ambient temperature is an enemy of long motor and cable life. Corrosion, if unchecked, is very instrumental in reducing the length of runs a unit may enjoy. Gas is usually most meaningful in terms of reduced volumetric efficiency but it can also be the cause of severe pump wear if allowed to gas-lock the pump while the motor continues to run. In this case, a damaging process known as cavitation occurs within the stages of the pump, and they will wear out in a very short time. As noted in the example of equipment selection, fluid viscosity, while admittedly being a somewhat nebulous factor, is going to restrict the ability of an impeller to generate hydraulic head, especially when the viscosity amounts to 100 SSU's or greater.

Of all the limitations which exist for submersible pumping operation, probably the most stringent is the presence of free solids in the fluid. Sand is the most prevalent of the free solids. In unconsolidated sandstone reservoirs where the loose sand is not kept out of the fluid entering the borehole, one may as well not figure on using a submersible pump without a great amount of expensive repairs and maintenance. The abrasive effect of free sand moving with great velocity upon or across any surface, be it metal, plastic, rubber, or what have you, is fairly well known. Being a silicate, a loose sand grain is at least as hard and probably harder than any material used in the pump. Therefore, with the impellers turning near 3500 RPM, the abrasive effect of a continuous stream of sand on the internal parts will wear them down to ineffectiveness within a very short time and to total destruction soon after that. Nevertheless, there are cases in which operators have chosen to live with this problem where they enjoy such a rate of oil production that the operation of submersibles, even though quite costly, is still very profitable. This is true today in certain areas in California. An outstanding example of this is the old Oklahoma City Wilcox Field where great volumes of sand were produced.

A limited amount of sand produced for but a short time is not uncommon and usually presents no problem. Such may be the case following a frac job where, say, two or three hundred pounds of frac sand may be produced initially but which clears up after a few hundred barrels of fluid are produced. Similarly, some sandstone formations may be quasi-unconsolidated in that loose sand is given up at first but drops off to where the fluid is substantially sand-free once a stabilized rate of production has been attained. However, such formations can be problems where intermittent operation takes place and the stop-and-start running of the pump periodically creates unstabilized producing conditions.

VARIATIONS OF SUBMERSIBLE PUMP APPLICATIONS

Submersible pumps have been applied in a variety of ways which are departures from the ordinary means of application. Three such variations are shown in Fig. 5. They are: direct injection of water into one or more waterflood injector wells in a closed system (Fig. 5a); injection of water from an upper zone directly into a lower zone in the same well using an inverted pump (Fig. 5b); and "staging" complete subsurface units in order to overcome total head greater than the head capability of one unit (Fig. 5c).

It is often desirable to pump directly into injection wells without first going through surface storage facilities. The economics of such an injection program are certainly enhanced by the elimination of equipment necessary for storage and subsequent injection. Furthermore, there is often the added advantage of reducing the oxygenation of the water which, in many cases, is a cause of fluid corrosiveness. Figure 5a schematically illustrates a typical installation of this type which is currently in operation in a West Texas waterflood. Here, the water supply well is very shallow, being less than 100 ft in depth. As a result, practically all of the pump's generated head is used for supplying the required injection pressures. The output of the well, about 800 BWPD, is distributed between two injection wells with one well receiving approximately three times the amount injected in the other. Injection pressures are in the range of 1200 psi.

Figure 5b shows a representation of an inverted pump installation in West Texas. This pump was specially designed for use in a dump flood project in which a shallow water source supplied water for direct injection into a lower zone undergoing flooding. In this particular waterflood, a greater volume than was available through gravity was desired for injection. A tension packer run on the tubing between the upper and lower zones packs-off about 30 ft above the pump. Water enters the tubing through slots located a few hundred feet above the water-producing horizon. A turbine meter placed in the tubing string meters the water as it is pumped into the lower zone located roughly 3000 ft below the pump.[1] This pump is "special" in that its stages are inverted and there is a special thrust bearing placed at the top of the pump. The direction of the rotation of the motor is reversed, that is, counterclockwise instead of clockwise. Where this method of injection is feasible, the savings in surface distribution, storage and injection facilities are obvious.

Another variation on the applicability of submersible pumps is found in a Nevada water supply well (Fig. 5c). Here the total head requirements at the desired volume were higher than what could be supplied with the horsepower of the largest motor available at that time. Conveniently, however, the operator had

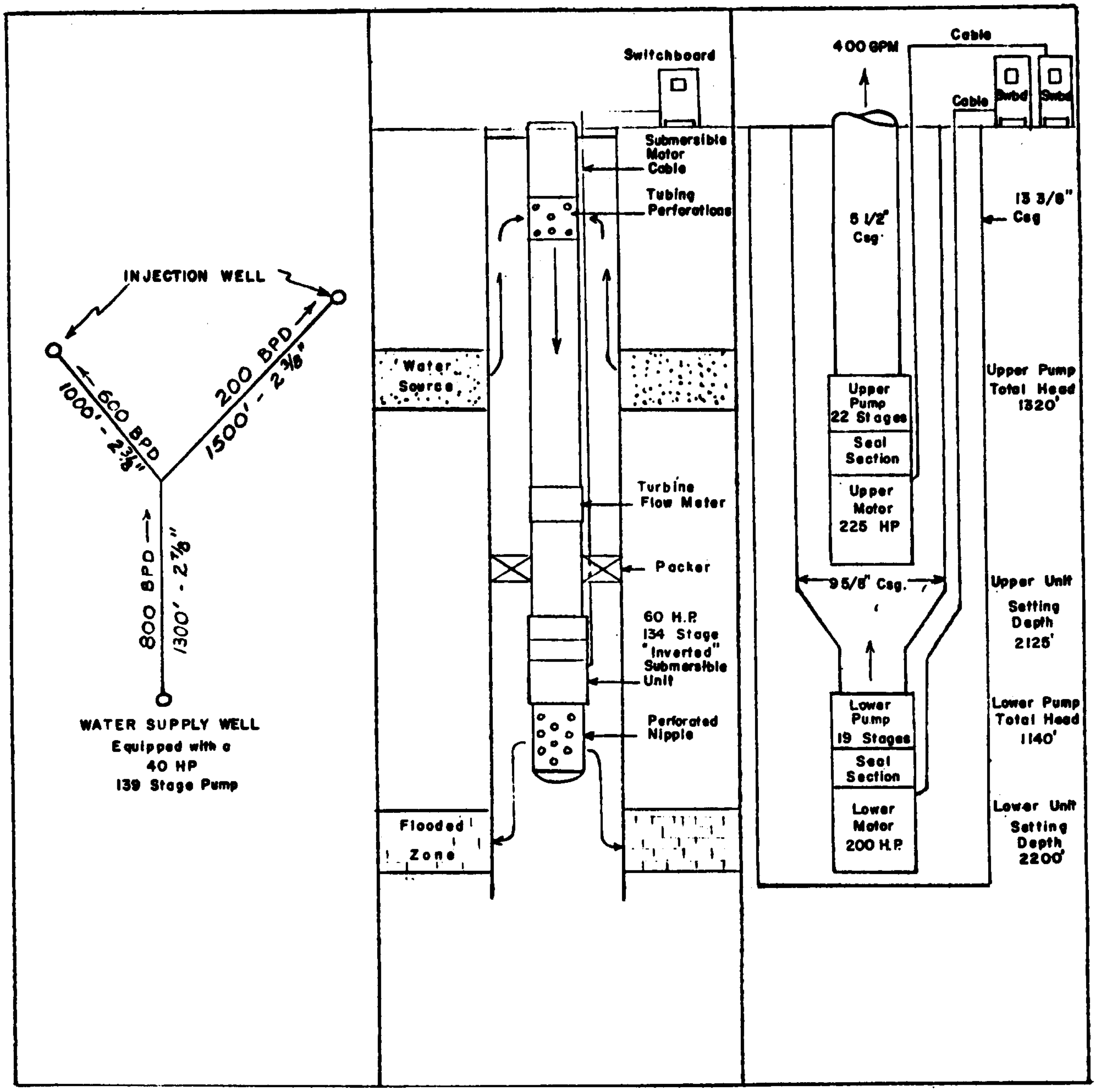


Fig. 5a-Schematic plat showing direct injection method used in a West Texas waterflood.

Fig. 5b-Schematic illustration of "Inverted" submersible unit injecting water directly from upper zone to a lower zone in West Texas waterflood.

Fig. 5c-Schematic plan of staging two complete submersible units in order to meet high volume and head requirements in a Nevada water supply well.

Fig. 5

VARIATIONS OF SUBMERSIBLE PUMP APPLICATIONS drilled a large-diameter well and had set 13⅜-in. casing at 2200 ft. The approach to the problem was to run one 200-HP submersible unit on the end of a string of 9⅝-in. casing swaged off the 5½-in. casing to which the pump head was attached and set near bottom. A 225-HP unit was run on 5½-in. casing within the 9⅝-in. casing. The two pumps together were then able to pump a total of well over 400 gallons per minute against a total head somewhat greater than 2200 ft.

ECONOMICS OF PRODUCING WELL APPLICATIONS

In those states such as Texas, Oklahoma, and New Mexico, where producing wells are subject to rather strict proration, most submersible applications are found in water supply wells for waterflood projects. There are, however, a number of installations in high water-cut producing wells located in active natural water drive reservoirs. As primary depletion in this type of field progresses, more and more operators have found that high-capacity pumping will economically prolong the life of the field and provide a greater ultimate recovery than was possible with conventional beam-type pumping.

In his report on a few cases supporting the economics of high-volume pumping, R. W. Parker graphically demonstrates the solid basis with which submersible pumps may be employed in certain types of producing wells.[2] In some instances, many high water-oil ratio wells are abandoned within a short time because the amount of oil pumped by conventional methods is not economic. However, given a total fluid volume great enough for a submersible pump and favorable oil allowables, one can often improve the rate of production and ultimate recovery from such a well and provide a respectable profit where none would have been possible without high-volume pumping. In his paper, Parker cites cases where the future recoverable oil with submersible pumps was projected to be from 8.6 to 32 times the amount recoverable by conventional pumping. What is equally significant is that the average time for recovering this increased production was only about 2.8 times as long as the average time indicated for the lesser recoveries. Where discounting of future income is important in assessing the economics of a project, this time factor bears considerable weight.

A proper economic analysis of the feasibility of submersible pumps must include the determination of comparative equipment costs and operating costs of the various lifting methods. Probably the most objective comparison of the costs of pumping high volumes is presented by E. A. Riley in his paper on solving the problem of excessive water in the waterflood producing wells with big-capacity pumps.[3] In that paper, the initial equipment cost and lifting cost per barrel are compared for conventional, hydraulic and submersible methods of high-volume pumping, as shown on Fig. 6.[3] Examination of Fig. 6 shows the rapid rise in both original equipment cost and per-barrel lifting costs for conventional beam type pumps as compared with submersible pumps. It is also evident that submersible pumping meets certain requirements which no other pumping method can; volumes in excess of 2000 BFPD from depths greater than 1500 ft cannot be economically produced by any other mechanical pumping method.

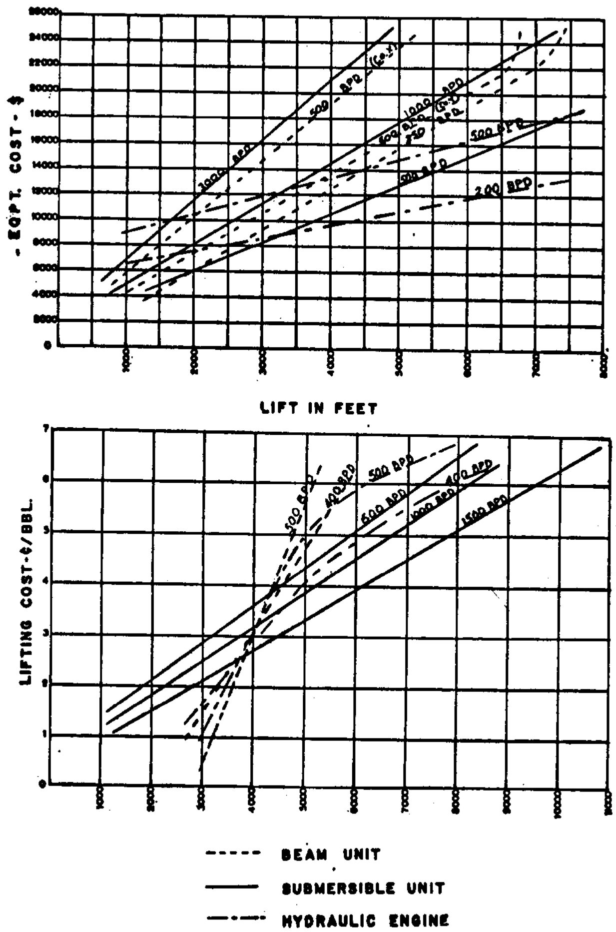


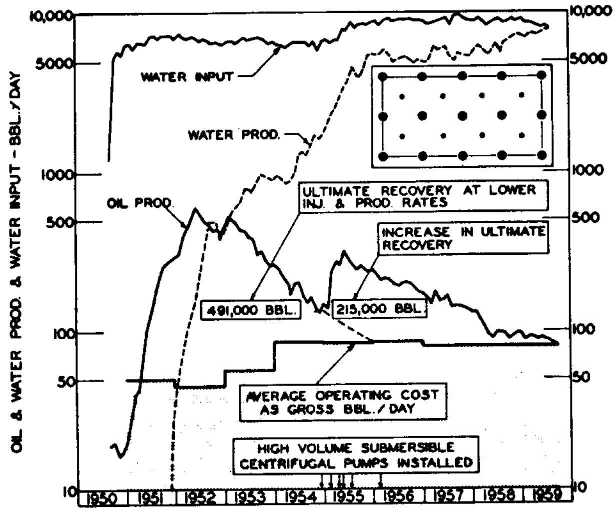
Fig. 6

Upper chart shows comparative initial equipment costs for submersible, beam, and hydraulic installations while the lower curves compare the lifting costs of the three pumping methods.[3]

The thesis that submersible pumping is realistically economical in certain high-volume applications gains substance from the experience of various operators who have run submersibles in producing wells within waterfloods. As one would logically suspect, certain conditions exist within waterfloods which necessitate the consideration of high-volume pumping. Where the physical conditions of a reservoir and geometry of the flood pattern combine to promote a great influx of injected water into various producing wells, operators are faced with several alternatives. These alternatives include plugging the "break-through" wells, reducing the rate of injection, remedial work in high-injection-rate wells, or pumping high volumes from the producing wells. It has been shown in some floods that the latter alternative is preferred from the standpoint of increased rate of production, ultimate recovery, and overall profitability.

A good example of high-volume submersible pumps being profitably applied in a waterflood is given by R. C. Earlougher and E. T. Guerrero in their treatise on developments recently introdued to waterflooding.[4] An Oklahoma lease of 280 acres consisting of eight 10-acre 5-spot patterns was at a producing rate close to its economic limit when five of the wells were fractured and equipped with submersible pumps. The lease producing rate was more than doubled, almost immediately, to around 400 BOPD, and the life of the project was economically extended by more than three years during which the ultimate recovery was increased by 215,000 barrels of oil. This history is shown by decline curves in Fig. 7.[4] Note here that the average operating cost per barrel after the installation of submersible pumps did not vary from that experienced when the lease was equipped with conventional pumps only.

It is apparent that submersible pumps are feasible in high water-ratio wells found in either natural water drive reserviors undergoing primary depletion or in waterflood producing wells. In the latter case a great deal of oil can often be gained by being flushed from the rock matrix or fracture systems with relatively high volumes of injected water. Certainly it would be advisable for those charged with the responsibility of increasing producing rates and ultimate recoveries to investigate the possibility of installing submersible pumps in those producing wells which are candidates for high-volume pumping.



HISTORY OF OKLAHOMA 80 ACRE LEASE SHOWING EFFECTS OF HIGH WATER INJECTION AND PRODUCTION RATES

Fig. 7

HISTORY OF OKLAHOMA 80 ACRE LEASE SHOWING EFFECTS OF HIGH WATER INJECTION AND PRODUCTION RATES[4]

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