Subsurface Electric Pump Well Test Analysis

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INTRODUCTION

In the spring of 1968, Continental Oil Company initiated a program to determine the causes of poor subsurface electric pump performance. An analytical system was developed to evaluate the performance of subsurface electric pumps. The results of the analysis indicated the need for Company schools at which operating personnel and engineers could become familiar with the proper selection and operation of this equipment. The first one-week school was held in November of 1969. This paper primarily covers the well test analysis, but prior to discussing the well test form it is necessary to review important aspects of the subsurface electric pump. Each portion of the pump will be discussed with major problem areas stressed.

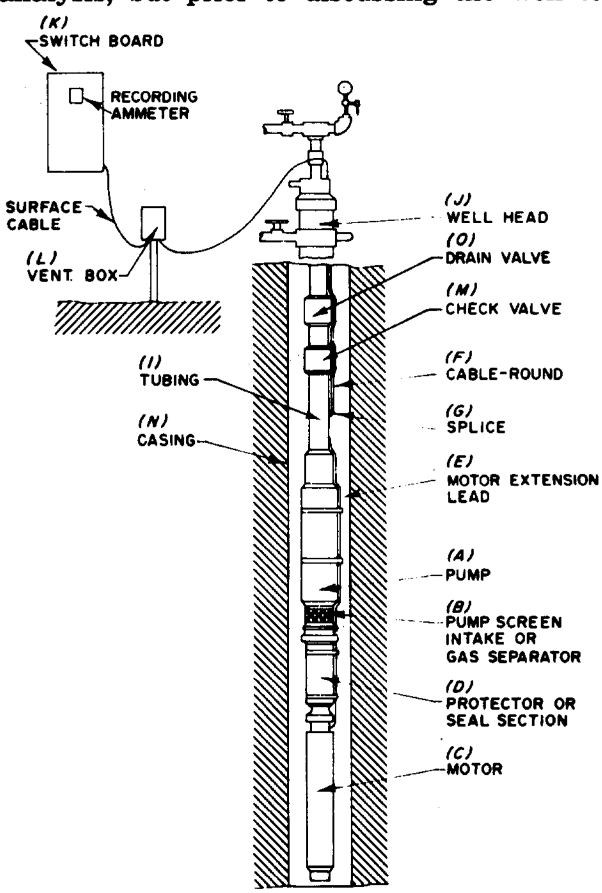


FIGURE 1

SUBSURFACE ELECTRIC PUMP DESCRIPTION

A typical subsurface electric pump arrangement is shown in Fig. 1. The electric motor is on the bottom of the assembly. Above the motor is located the thrust bearing and seal assembly, the pump intake, and the multiple-stage centrifugal pump which is attached to the tubing string. This allows all produced fluids to enter the wellbore below the electric motor and flow around the motor to the pump suction.

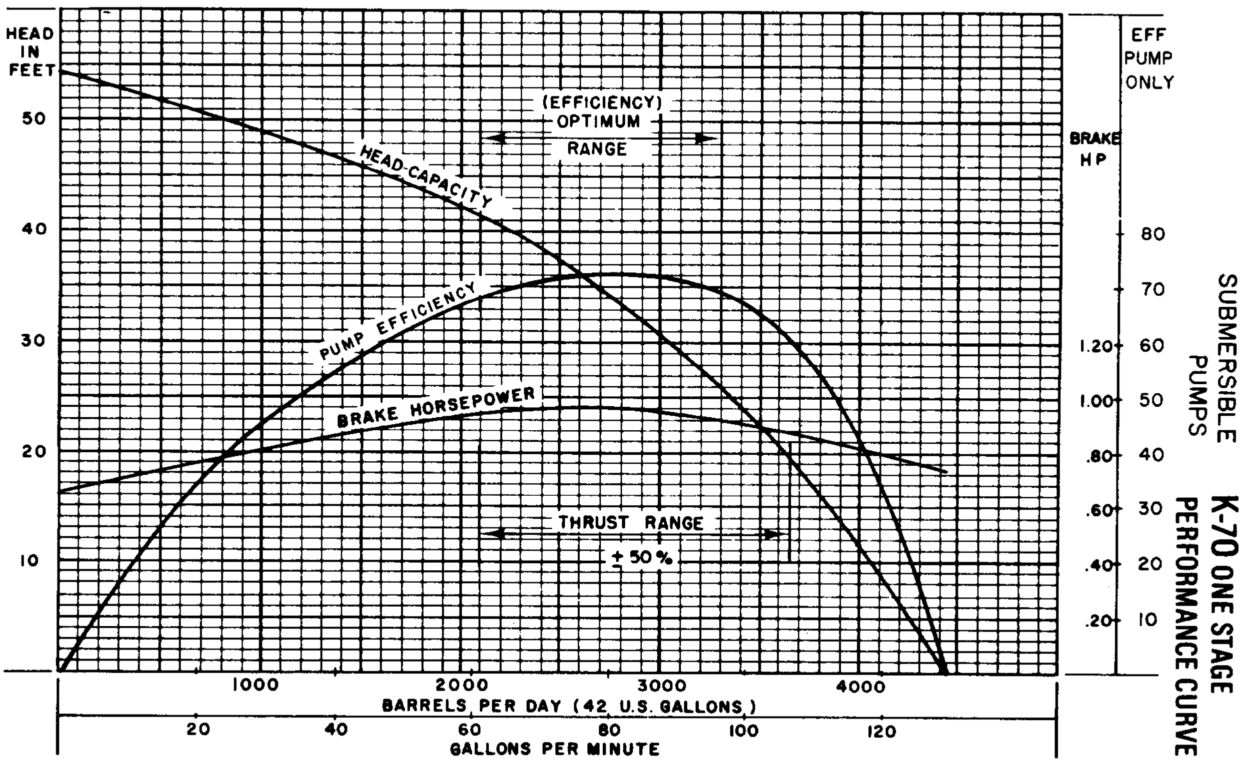
The electric motor driving the centrifugal pump is a two-pole, three-phase, squirrel-cage, induction motor. These motors run at 3450 rpm on 60-cycle current. Variations in the cycle frequency cause a variation in the motor rpm. This is not a problem when using most purchased electrical power. The design and operating voltage of these motors can be as low as 220 volts and as high as 2300 volts. The shaft output of these motors may be from 1/3 up to and including 520 horsepower. The wellbore fluids must absorb the heat that is generated within the motor. Experimentation has shown that the wellbore fluids must pass the motor at a minimum rate of 1/2 to 3/4 of a foot per second in order to cool the motor properly. Due to variations in the heat conductivities of oilwell liquids, plus the poor conductivity of gas, it is recommended that this rate be in excess of 1 foot per second. If this rate cannot be attained because of a large casing diameter and small motor diameter, a motor shroud may be used to decrease the annular area and increase the velocity of the fluid past the motor.

The thrust bearing or seal assembly is located on top of the motor and at the base of the pump intake. This assembly connects the pump housing to the motor housing, connects the driveshaft of the motor to the pump shaft and houses the pump shaft thrust bearing assembly. It also provides a seal between the oil in the motor and the wellbore fluids, but allows pressure communication between these fluids. The thrust bearing located within this housing is designed for one direction of rotation; any reverse rotation will cause premature failure. Reda designs for counterclockwise rotation looking from the top down and B. J., OiLine, and Oil Dynamic design for clockwise rotation. The components of the various pump systems cannot be mixed. The direction of rotation must be checked as soon as possible after start-up. The method used to check the direction of rotation is explained in the well test calculation.

Above the thrust bearing assembly is located the intake to the multiple-stage centrifugal pump. The discharge rate and pressure of a centrifugal pump depend upon the following factors:

1. Speed (rpm)
2. Size of the impeller
3. Impeller shape
4. Physical properties of the fluid handled
5. The dynamic head against which the pump is operating
6. The number of stages

Each of these items must be considered in selecting a pump. Pump manufacturers have developed performance curves based upon a water test for each pump size and impeller type (See Fig. 2). Three basic characteristics are shown on each performance curve. These are (1) The head capacity curve, the volume output as a function of the head measured in feet of fluid being pumped; (2) A plot of the pump performance efficiency against the volume output; and (3) A plot of the brake horsepower required as a function of volume output. It should be noted that Reda's pump performance curves are for 100 stages while B. J.'s, OiLine's and Oil Dynamic's performance curves are for a single stage. The manufacturers' literature lists optimum operating ranges. These should be plotted on the pump characteristic curves as has been done on Fig. 2.



K-70 PUMP FOR 7" O.D. WELL CASING

SERIES 513 | 3475 R.P.M. | WATER TEST NO. 82-12-60 | SPECIFIC GRAVITY 1.0

FIGURE 2

The impellers are a fully enclosed curved vane type. These impellers are designed to have minimum thrust, either up or down, when operating at the peak efficiency. Pumps must be operating within the optimum ranges recommended by the manufacturer to minimize the thrust wear on the impellers and thrust bearings. It is preferable to operate between the peak efficiency and the upper optimum range (Fig. 2). Then, as wear on the pump gradually lowers the capacity, operation in the desired range can be maintained for a longer period.

Viscosity, compressibility of fluids, and specific gravity affect the performance of a multiple-stage centrifugal pump. Most pumps have been designed for and tested in water with a viscosity of 30 Saybolt Second Units (SSU) or one centipoise (cp) at 69° and a specific gravity of 1.0. For viscosities other than 30 SSU or 1 cp, a laborious calculation can be made to offset the effects of viscosity.

Multiple-stage centrifugal pumps are designed to handle a noncompressible fluid. Water, oil and gas which remain in solution at the pump suction pressures are not considered compressible; however, free gas at the pump suction is compressible and will greatly reduce the efficiency of the pump. The pump manufacturers have gas separators which are used in place of the normal pump intake. These separators can handle up to 1500 cu ft/bbl. In rare instances, such separators have been operated as high as 3000 cu ft/bbl of fluid. However, they will not remove all of the free gas. It is recommended that a gas separator be used in any well that produces a measurable amount of free gas.

The specific gravity of the fluid in the pump directly affects the horsepower required to drive this pump. For a specific gravity other than one, the required horsepower is found by multiplying the performance curve horsepower by the new specific gravity.

The heads generated by each stage of a multiple-stage centrifugal pump are additive. The total dynamic head is the pressure against which the pump is operating, expressed as feet of the fluid being pumped. The dynamic head is composed of four items; (1) the total pump suction head, (2) the tubing string head, (3) the friction loss in the tubing string, and (4) the surface tubing pressure. The required number of stages in the pump system is found by dividing the total dynamic head of the well by the head generated by a single stage of the pump type and size to be used. The only limit to the number of stages which can be used in one pump is the strength of the center shaft that turns the impellers.

The electrical power to drive the motor is conducted from the surface controller to the pump by a special three-conductor cable and spliced at that point to the motor extension lead which is connected into the upper portion of the motor. In most cases the size of the motor extension lead is fixed by the manufacturer. The type of insulation for this lead can be specified by the purchaser. In the majority of cases it is recommended that the insulation with the highest temperature rating be selected. The main cable, from the surface controller to the splice, should be round cable wherever possible, because this type of cable will provide a balanced voltage and current to the motor. The minimum size of cable to be used with the various motors can be determined from charts furnished by the manufacturers. The cable insulation is adversely affected by temperature, pressure, and wellbore fluids, as well as age. The necessity for the cable insulation to resist hydrocarbons and other wellbore fluids is obvious. What has not been normally recognized is the effect of temperature on the insulation life. The cable insulation is subjected to the combined temperatures of the wellbore, heat generated by the motor and pump, and the heat due to the resistance to current flow in the conductors. Of these, the wellbore temperature and the heat due to the resistance to flow of current are the most important. Figure 3 was prepared with the aid of AIEE-IPCEA Ampacity tables. Similar graphs have been prepared for the other sizes of round cable. To use these graphs, one must know the maximum wellbore temperature, which is assumed to be the bottomhole temperature, and the amperage to be carried by a prescribed cable size. The round cable conductor temperature may be found as shown in Example A on Fig. 3. For a flat cable, a multiplier of 1.08 times the amperage in the round cable is used as shown in Example B. Consultations with the pump manufacturers are helpful in selecting an insulation which will withstand this temperature. The insulation must not only withstand the temperature but be capable of combating the environment in which it will be run. The protective armor around the cable jacket should be Monel in cases where corrosive environments are found.

The electrical controls located on the surface between the secondary side of the transformer and the wellhead should be those recommended by the manufacturers. In all cases a recording ammeter should be included as part of the minimum required equipment. Automated equipment may be added to this control system. In all cases local electrical codes and conditions must be considered when installing these controls.

Miscellaneous equipment used on subsurface electric pump installations includes:

1. The wellhead must be equipped with a tubing head bonnet which provides for a positive seal around the cable and the tubing. All tubing connections, including the shutoff valves must have a pressure rating greater than that equivalent to the maximum head which can be generated by the installed pump.
2. A check valve is used to maintain a full column of fluid in the tubing. This valve should be located 2 or 3 joints above the pump.
3. A drain valve is installed one joint above the check valve and is used to eliminate pulling wet strings.
4. Centralizers should be used to center the motor and pump for proper cooling. Eccentric tubing centralizers should be

WELL TEMPERATURE VS. CURRENT - NO. 1 ROUND CABLE

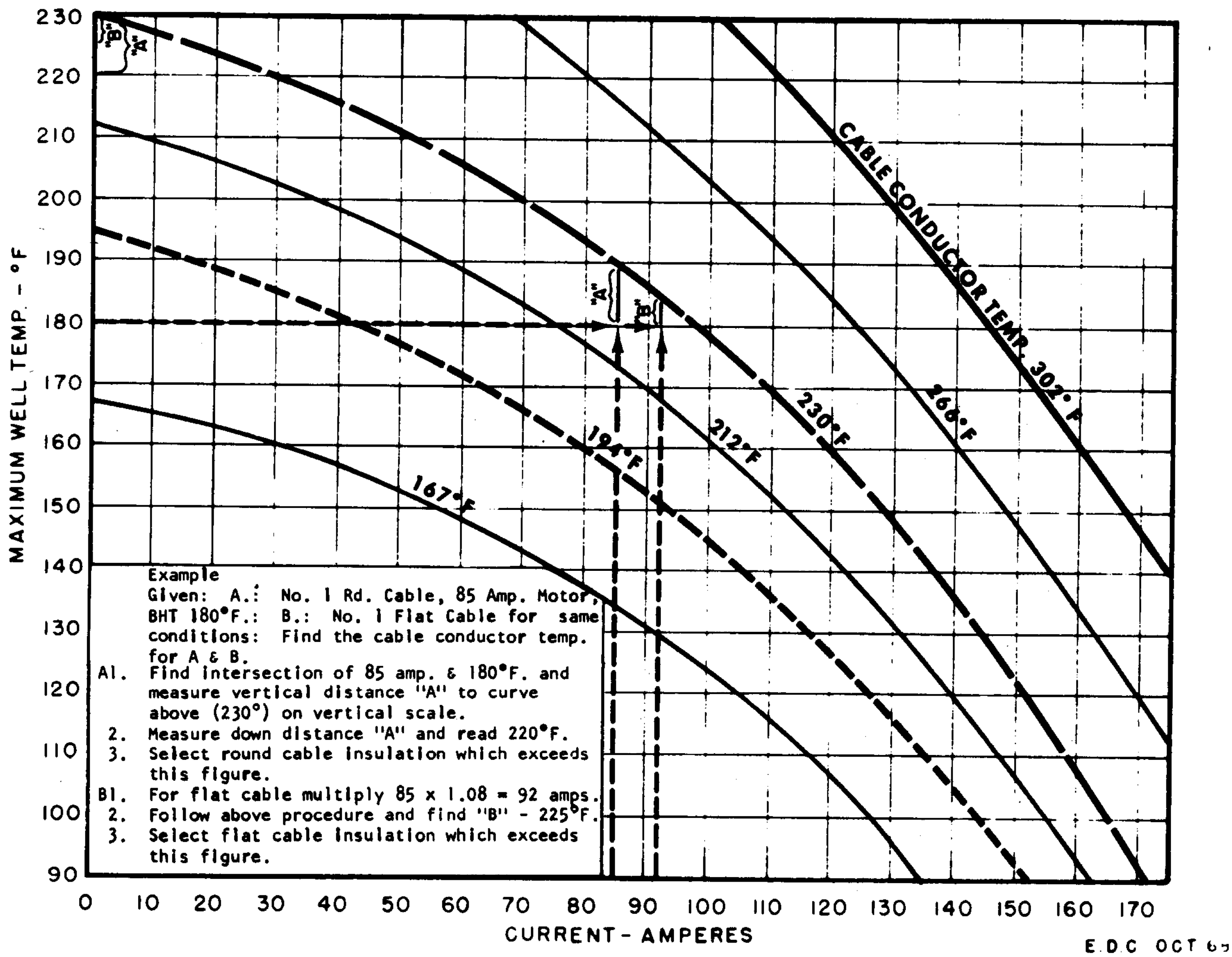


FIGURE 3

540 SERIES MOTOR - 60 CYCLE
BASIC CHARACTERISTICS

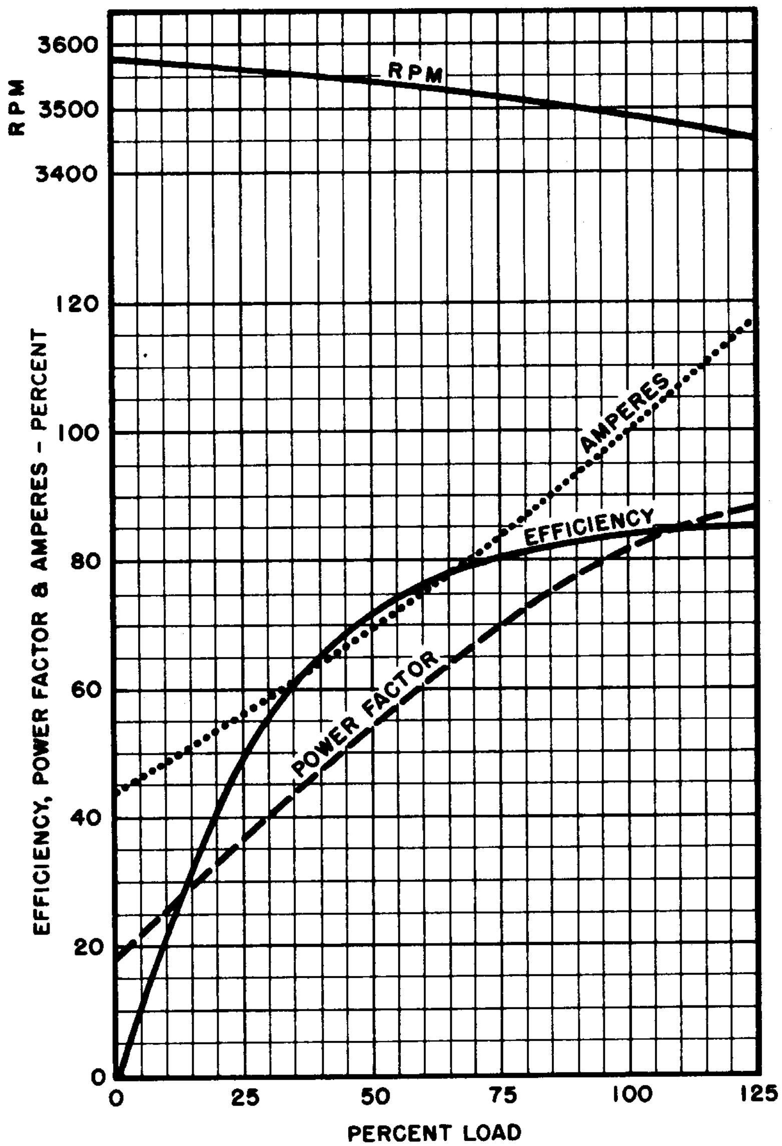


FIGURE 4

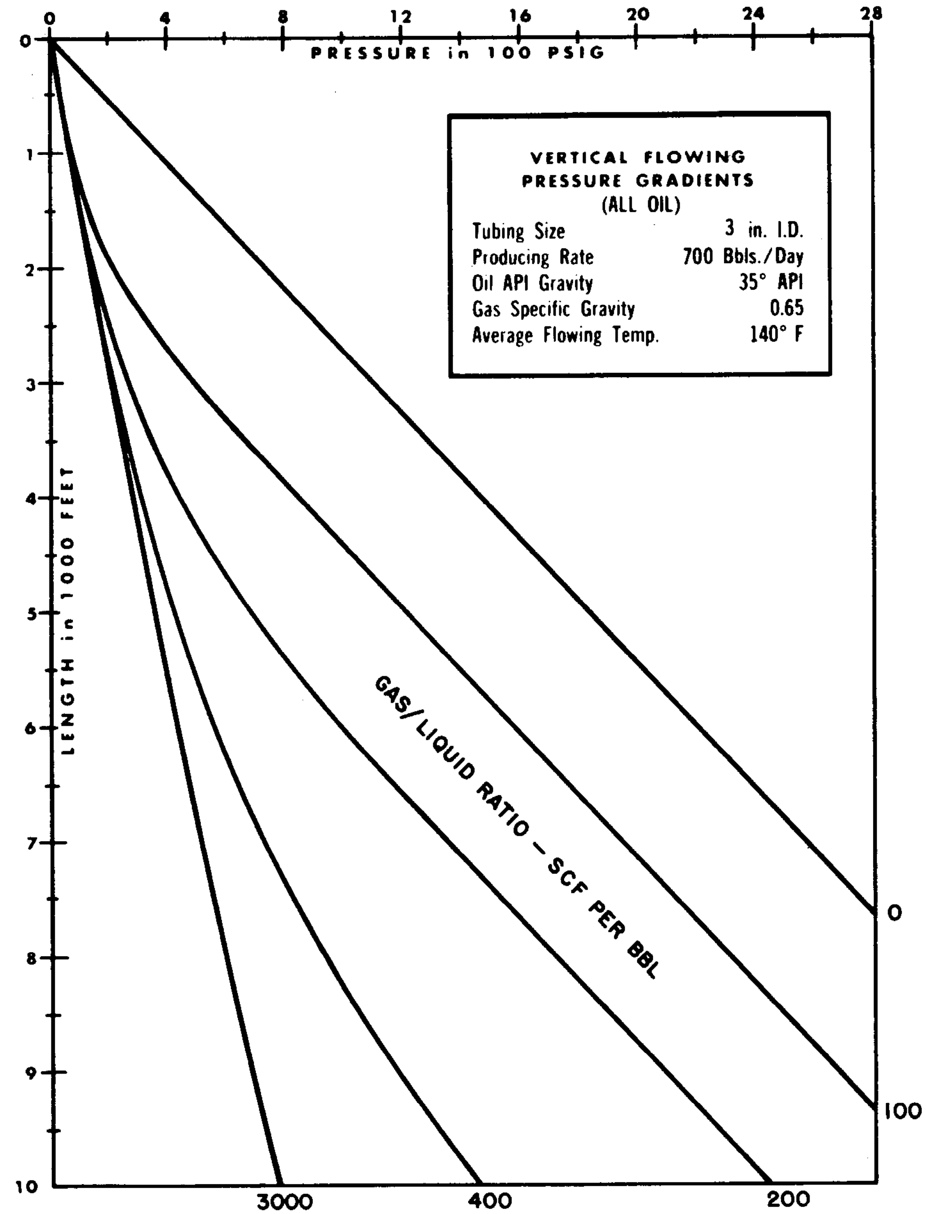


FIGURE 5

used in crooked or deviated holes to keep the cable from rubbing the casing while running into the hole.

5. Cable guards are installed over the flat cable which is used as a motor extension lead. These guards are galvanized steel and should be replaced each time the pump is pulled. The extension lead itself is wrapped with a metallic wrapping. This wrapping should be Monel where corrosive fluids are being handled.

The pump, motor and cable must be assembled and handled during installation or removal according to the manufacturer's instructions. The manufacturer's field service man should be on all such jobs and his experience fully utilized. It is recommended that he be allowed plenty of time to use special tools and instruments to check out the equipment. Cleanliness is of paramount importance during the final assembly of the unit; dirt, rough handling and the like can cause a premature failure.

SUBSURFACE ELECTRIC PUMP TESTING AND ANALYSIS

Periodic tests and equipment analyses are required to obtain the most efficient service from any artificial lift system; the subsurface electric pump is no exception. The following test schedule is recommended:

1. Upon initial start-up
2. Five to seven days after start-up
3. On new installations, every two weeks until the well is stabilized
4. Monthly thereafter

The well test form (Appendix 1) should be used to record the test data on subsurface electric pumps. This form is arranged to assist in making the necessary calculations on the form (Appendix 2) or to facilitate the preparation of load sheets used with the computer program. In order to make the calculations shown on the second page, pump characteristic curves (Fig. 2), motor characteristic curves (Fig. 4), and a means to determine the vertical flow gradients (Fig. 5) for the installation will be required. The nomenclature used on the well test form is given on Appendix 3.

The importance of several individual items on the calculation form (Appendix 1) is discussed below:

Item No. 8, "Pump Capacity" is the ratio of the production rate to the manufacturer's indicated rate at peak efficiency expressed as a percentage. It should be between 75 per cent and 125 per cent in order to fall within the optimum range listed by most manufacturers. If this number is greater than 125 per cent, a tubing choke should be utilized to pinch the rate back to the maximum optimum rate. A high percentage may follow a shut-in period during which the fluid level rose to a higher level than normally seen during stabilized production. In this case, after a short producing period, the choke should not be necessary. A high figure may result from underestimating the well's productivity or miscalculating in selecting the pumping system. If the pump capacity is below 75 per cent it may be possible to lower the surface pressure and thus increase the "Pump Capacity". If Item No. 8 is below 50 per cent, it is an indication that the pump is turning in the wrong direction and the motor leads may be reversed. The pump should not be run at less than 50 per cent of its peak efficiency.

Item No. 9 is the rate at which the fluid is passing the motor housing and it should be greater than 1.0 feet per second. If it is less than 0.5 feet per second, the pump should be shut down unless it is a very cool well.

Item No. 19, "Pump Efficiency", is the head produced by the pump as a percentage of the theoretical head that the pump should produce. It should be between 80 and 110 per cent. The figure should be in general agreement with that calculated under Item No. 8, Pump Capacity. A number greater than 100 per cent will usually indicate help from solution gas in the tubing or a higher operating casing fluid level than estimated. A number lower than 80 per cent would usually indicate gas going through the pump, a false fluid level, a hole in the tubing, pump wear, a low well productivity, or excessive number of stages.

The *"Motor Efficiency", Item No. 25,* is the horsepower required to drive the pump as a percentage of the horsepower output of the motor, and it should be between 80 and 100 per cent. If it is greater than 100 per cent, the effective specific gravity of the produced fluid may be less than estimated. If the number is much greater than 100 per cent, it is possible that the pump shaft has been broken, pump has gaslocked, or that the pump intake is plugged. A calculation of less than 80 per cent would

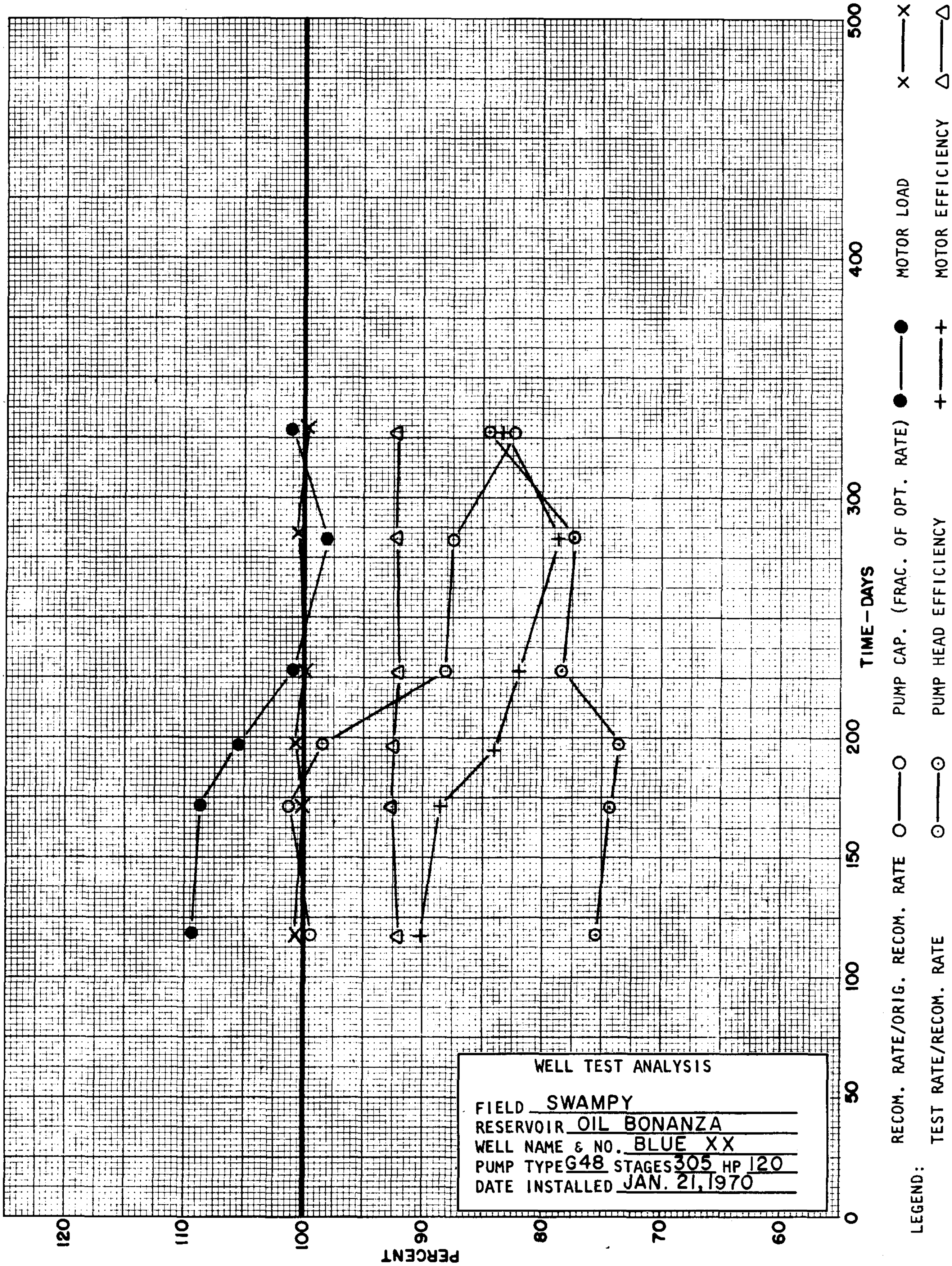

WELL TEST ANALYSIS
FIELD SWAMPY
RESERVOIR OIL BONANZA
WELL NAME & NO. BLUE XX
PUMP TYPE G48 STAGES 305 HP 120
DATE INSTALLED JAN. 21, 1970
TIME—DAYS
PERCENT
0
50
100
150
200
300
400
500
120
110
100
90
80
70
60
LEGEND:
RECOM. RATE/ORIG. RECOM. RATE
PUMP CAP. (FRAC. OF OPT. RATE)
MOTOR LOAD
TEST RATE/RECOM. RATE
PUMP HEAD EFFICIENCY
MOTOR EFFICIENCY

FIGURE 6

indicate a binding shaft, that the specific gravity of the produced fluid is greater than estimated or that a high viscosity fluid is being handled. Improper current adjustment may also cause the reading to be outside the recommended limits; a voltage adjustment to obtain minimum amperage should be made.

The *"Motor Load", Item No. 26,* is the horsepower output of the motor as a percent of the nameplate horsepower of the motor and should be between 75 and 110 per cent. If Item No. 26 is outside the suggested limits, the first step is to check the balance of the voltage and amperage of each phase and to make necessary corrections. The second step is to adjust the voltage to obtain the minimum amperage. Item No. 26 is an indication of whether or not the motor is the proper size for the pump and the well conditions. If the steps in the previous paragraph do not bring the motor load within the 75 to 110 per cent range, the motor is improperly sized.

The answers which are calculated on lines 8, 19, 25, and 26 (those in a square) are plotted on a graph paper vs. time since the installation of the pump. These items primarily reflect the mechanical condition of the pump. No one figure can be considered as an absolute answer. Gradual changes reflected on the graph usually show normal wear on the equipment. Abrupt changes on the graph are an indication of a poor test or an incipient failure.

Fig. 6 is an example plot of actual well data taken during a period 125 days to approximately 325 days after installation. It shows that the pump capacity started out above 100 per cent and dropped down to the 100 per cent line which is right on the peak rate of the pump. This should provide the maximum life of the pump from a capacity standpoint. The motor load is right on the 100 per cent line which is the correct size motor to be used in this case. The motor efficiency is very good at 92.5 per cent and indicates that the motor is operating properly. The pump head efficiency shows a gradual decrease indicating that the pump may be wearing slightly; however, the last test indicated that the pump head efficiency had climbed slightly, which could be the result of a slight change in specific gravity of the produced fluids.

Continental Oil Company's computer program utilizes the same calculation as the well test form to evaluate and select the best Reda and B. J. pump for an installation based on the well test. When the computer selects the same pump that is being evaluated, the proper pump has been installed. The stand-by pump for a well should be the one selected by the computer based on the latest well test.

When calculations are made by the computer, two additional data items are available for use on the graph. These two primarily reflect reservoir conditions and producing characteristics. The computer - calculated recommended rate is defined as the maximum production rate of the well with the pump suction located 150 feet above the top perforation and the pump suction having 100 feet of liquid submergence. The recommended rate divided by the original recommended rate indicates the change in producing characteristics of the reservoir. This data, plotted on Fig. 6, has slowly declined indicating that the current producing capacity is 82 per cent of the original recommended rate. The test rate divided by the recommended rate was staying fairly uniform and therefore indicates that the pump is producing as much of the oil as the well is capable of producing.

If one would look at only the first test data one would say, "Wait a minute, we're underproducing this well"; however, after a well has continued to produce as this one has produced for 200 days, and everything is changing in a uniformly slow manner within limits, the pump's operation must be considered satisfactory. It appears that the pump should continue to perform satisfactorily for another 250 days.

ECONOMICS

Company schools and operating analyses are showing a payout. Personnel understand the reason for and follow the manufacturer's recommendations during the installation and removal of a pump. When pumps do fail, the pump and the well test data are examined to determine the cause, and whether corrective actions are needed. Pumps are not automatically repaired and rerun without determining whether or not they are properly sized.

Prior to 1968, Continental Oil Company's subsurface electrical pump average life was 165 days. Repair cost for each pulling job has been $4500. The current average life has been extended beyond 225 days. The goal is to average 450 days per installation which is not unreasonable since some installations have operated 1700 days.

ACKNOWLEDGMENTS

The author wishes to thank Continental Oil Company for permitting him the opportunity to present this paper and for the assistance that has been given by the Reda Pump Company, Bartlesville, Oklahoma, and the Byron-Jackson Centrilift, Tulsa, Oklahoma. They have provided data submitted here without which this paper could not have been presented.

APPENDIX 1

Well Name & No. ________
Date of Test ________

SUBSURFACE ELECTRIC PUMPS
INITIAL OR MONTHLY TEST DATA
FIELD________ RESERVOIR________

Total Depth________($^{KB}_{GL}$) Perf. Inter: Top________ Bottom ________
Min. Casing O.D. to Motor Depth ________ Casing I.D. @ Motor________
Tubing Size & Length ______ ______ Check - Drain Size & Location ______ ______

Pump:
Type_____ Peak Eff. Rate_____BPD No. Stage_____ Suction Depth (P.D.)_______($^{KB}_{GL}$)
Date Installed ________

Motor:
Series_____ H.P._______ Voltage_______ Amp._______ Depth Set________($^{KB}_{GL}$)
Date Installed________

Gas Separator:
Series_______ Type _______

B. H. P. Device:
Type_______ Depth _______ Scale _______

Cable:
Rd. Size & Length ______ ______ Flat Size & Length ______ ______
Oil Gravity ______°A.P.I. Oil Specific Gravity ________ FVF________
Water Specific Gravity ________ Gas Specific Gravity ________
Reservoir Temp. ______°F. Prod. Fluids Surface Temp.______ Oil Vis. @ Temp.____

A. Measured Data:

1. Length of Continuous Operation prior to this test ________ Hours or Days

2. Length of this test ________ Hours

3. Production During Test

A. Oil	________	Bbls.
B. Water	________	Bbls.
C. Gas produced through tubing	________	MCF
D. Gas produced up casing annulus	________	MCF

4. Pressures During Test

	Static		Pumping	
A. Well Head Tubing	________	psig	________	psig
B. Casing	________	psig	________	psig
C. BHP Device	________	psig	________	psig
D. Fluid Level (Sonic)	________	psig	________	psig
E. Header Pressure	________	psig	________	psig
F. Sep. Pressure	________	psig	________	psig

5. Electrical

	No Load	Running
A. Voltage to Control Box	________	________
B. Amps to Cable	________	________

NOTE: Items not actually measured indicate by (E) following number. A-Feb.,1970.

APPENDIX 2

B. Calculated Data - Pump Operating

7. RBPD = [(3A)x(FVF)+(3B)]x24/(2)=[( )x( )+( )]x24/( )=________bbls./day

8. Pump Cap.% of Peak Eff. Cap.=((7)/Peak Eff. Rate)x100=(/)x100= $\boxed{\_\_\_\_\_\_\%}$

9. $VFPM = \frac{.0119 \times (7)}{(\text{Casing I.D.})^2 - (\text{Motor O.D.})^2} = \frac{.0119 \times (\quad)}{(\quad)^2 - (\quad)^2} =$ ________Ft./Sec.

10. WC = (3B)/[(3A)+(3B)] = ( )/[( )+( )] = ________Fraction

11. GLR = (3C)/[(3A)+(3B)] = ( )/[( )+( )] = ________Cu.Ft/Bbl

12. $TH_{(Tubing)} = P_{(AP)}* =$ ________psi

13. FGP = ([(10)x(W Sp.Gr.)]+[(1-(10))x(Oil Sp.Gr.)])x .433 =
([( )x( )](1-( ))x( )]) x .433 = ________psi/ft.

14. PSP (Ball)=(4C)-[(13)x(BHPD-P.D.)]=( )-[( )x( )-( )]________psi

15. PSP (Sonic)=(4B)+[.433x(Oil Sp.Gr.)x(PD-(4D)]=( )+[( )x( )-( )]=________psi

16. TDP (System)=(12)-(14) or (15)=( )-( ) = ________psi

17. TDH (System)=(16)/(13) = ( )/( ) = ________ft.

18. Theo. TDH [Perf. Curve at (7)] = No. Stages x Head/Stage =
( ) x ( ) = ________ft.

19. Pump Head Eff. = [(17)/(18)] x 100 [( )/( )] x 100 = $\boxed{\_\_\_\_\_\_\%}$

C. Calculated Data - Motor Running

20. Cable Voltage Drop = (Cable Curve)xCable L.=( )x( ) = ________Volts

21. Voltage to Motor =(5A)-(20) =( ) - ( ) = ________Volts

22. Motor HP Output = .00192 x (21) x (5B) x P.F. =
.00192 x ( ) x ( ) x ( ) = ________HP

23. Sp. Gr. of Fluid Pumped = (13)/.433 = ( )/( ) = ________

24. Pump HP @ [Perf. Curve at (7)] = No. Stages x (HP/Stage) x (23)
( ) x ( ) x ( ) = ________HP

25. Motor Eff. = [(24)/(22)] x 100 (( )/( )) x 100 = $\boxed{\_\_\_\_\_\_\%}$

26. Motor Load of Rated = [(22)/(Rated HP)] = [( )/( )]x100 = $\boxed{\_\_\_\_\_\_\%}$

*$P_{(AP)}$ is the pressure above pump as determined by the Vertical Flowing Gradient Charts.

Remarks ____

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B-FEBRUARY - 1970

APPENDIX 3

TEST FORM NOMENCLATURE

Amp.	= Ampere or Amperes
BHP	= Bottom Hole Pressure
BPD	= Barrels per day
Cable L.	= Cable length in feet
Cap.	= Capacity
FGP	= Fluid Gradient Pump. – psi/feet
F.V.F.	= Formation Volume Factor at pump conditions
G.L.	= Ground Level Measurement for well depth zero reference point
GLR	= Gas Liquid Ratio in cu. ft. per Bbl.
GOR	= Gas Oil Ratio in cu. ft. per Bbl.
HP	= Horsepower
I.D.	= Internal Diameter in inches
KB	= Kelly Bushing or well zero reference point from which perforations, packer depths, liners, etc. are located.
MCF	= Thousand cubic feet of gas at standard conditions of 14.65 psia and 60°F.
Motor Eff.	= Motor Efficiency in this case is comparing the motor output to that theoretically being used by the pump in percentage
Motor O.D.	= Motor Outside Diameter and indicated by motor series as 540 Series of Motor in inches is 5.40"
Peak Eff. Rate	= This is the rate of the pump at peak efficiency on the pump performance curve
Perf. Inter.	= Perforated interval or open hole interval (top and bottom only)
P.F.	= Power Factor and is taken from motor curve at per cent of amps running to rated amps

TEST FORM NOMENCLATURE (CONTINUED)

PD	= Pump Depth is the pump intake depth
PHD	= B.J.'s Pressure-Heat-Damage measuring device
P(AP)	= Pressure above the pump while pumping in psig
Pump Eff.	= Pump efficiency in percentage in this case is the head generated compared to what it should have generated. To obtain overall pump efficiency by that obtained from the pump curves.
PSP (Ball)	= Pump Suction Pressure by Ball Sentry or PHD in psig
PSP (Sonic)	= Pump Suction Pressure by Fluid Level Measuring Device in psig
RPBD	= Reservoir Barrels per Day
Rd	= Round Cable
Sep.	= Separator or Heater treater pressure
Sp.Gr.	= Specific Gravity of fluid pumped as fraction
Theo. TDH	= Theoretical Total Dynamic Head generated by pump at tested rate in feet
TDH (Tubing)	= Total Dynamic Head in tubing in psig
TDH (Tubing)	= Total Dynamic Head of the pumping system psig and converted to feet
VFPM	= Velocity of Fluid Past Motor in ft./sec.
W.C.	= Water Cut as a fraction