# Recommended Practice for Sizing and Selection of Electric Submersible Pump Installations

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## TABLE OF CONTENTS



**Note:** This is the first edition of this API Recommended Practice. It supersedes API Recommended Practice 11U (RP 11U) second edition, May 30, 1986 which was submitted to be renamed and reaffirmed at the 1992 Standardization Conference as reported in Circ PS-1985, and subsequently approved by letter ballot.

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# RECOMMENDED PRACTICE FOR SIZING AND SELECTION OF ELECTRIC SUBMERSIBLE PUMP INSTALLATIONS

## Foreword

1. **Jurisdiction:** This Recommended Practice (RP) is under the jurisdiction of the American Petroleum Institute (API) Committee on Standardization of Production Equipment (Committee 11).

2. **Purpose:** This document presents Recommended Practices for Sizing and Selection of Electric Submersible Pump Installations and Related Equipment.

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# SECTION 1
# GENERAL

## 1.1 INTRODUCTION:

**1.1.1** This RP is provided to meet the need for guidelines, procedures and recommendations covering Electric Submersible Pumps and related equipment. These Recommended Practices are those generally considered necessary for successful electric submersible pump operation. For installation see API RP 11R, *Recommended Practice for Electric Submersible Pump Installations.*

## 1.2 SCOPE:

**1.2.1** This Recommended Practice addresses the fundamental procedures for sizing and selecting electric submersible pumps and related equipment for various well conditions.

**1.2.2** This Recommended Practice is specifically prepared for installations in oil and/or water producing wells where the equipment is installed on tubing.

# SECTION 2
# TERMS, DATA AND CHARTS

## 2.1 DEFINITION OF TERMS:

**2.1.1** VD — **Vertical Pump Intake Setting Depth (Ft.)** — is the true vertical pump setting depth measured from the surface.

**2.1.2** MD — **Measured Pump Intake Setting Depth (Ft.)** — actual pump setting depth measured along the well bore. Theoretically, in non-deviated wells, MD = VD.

**2.1.3** FOP — **Fluid Over Pump (Ft.)** — calculated value

$$FOP = \frac{PIP\ (PSI)}{S.G. \times 0.433\ (PSI/Ft.)}$$

where: PIP = Pump Intake Pressure (PSI)
S.G. = Pump Intake Fluid Specific Gravity
0.433 = Conversion Constant (PSI/Ft.)

CAUTION: FOP calculated from a Sonic Fluid Level (FL) where FOP = VD - FL, can be very misleading because of the actual fluid gradient (PSI/Ft.) of the fluid in the annulus. This Fluid Level (FOP) may not give an equivalent Pump Intake Pressure.

**2.1.4** $H_D$ — **Vertical Lift (Ft.)** — Vertical Pump Setting Depth (VD) minus Fluid Over Pump (FOP). Therefore:

$$H_D = VD - FOP$$

**2.1.5** $H_F$ — **Tubing Friction Loss (Ft.)** — Pressure Loss expressed in feet due to fluid flow through the tubing, and is a function of fluid velocity and viscosity.

**2.1.6** $H_T$ — **Producing Tubing Head (Ft.)** — Producing tubing pressure at wellhead converted to head in feet by using the specific gravity of the fluid being pumped.

$$H_T = \frac{Tbg.\ Press.\ (PSIG)}{S.G. \times 0.433}$$

**2.1.7** TDH — **Total Dynamic Head (Ft.)** — is the head against which the pump is operating (discharging) expressed as feet of fluid being lifted.

$$TDH = H_D + H_F + H_T$$

where: $H_D$ = VD - FOP = Vertical Lift (Ft.)
$H_F$ = Tubing Friction Loss (Ft.)
$H_T$ = Producing Tubing Head (Ft.)

**2.1.8** S.G. — **Specific Gravity** — of oil, water and solution gas or any mixture thereof, at the pump intake.

**2.1.9** Visc — Viscosity (SSU)

**2.1.10** BHT — Bottom Hole Temperature (°F)

**2.1.11** GOR — Gas Oil Ratio (cu. ft./BBL)

**2.1.12** STBO — Stock Tank Barrels Oil (BBL)

**2.1.13** CUT — Water Cut (%)

**2.1.14** PVF — Pump Volume Factor

**2.1.15** GLR — Gas Liquid Ratio (cu. ft./BBL)

**2.1.16** KVA — Transformer Power Rating

$$KVA = \frac{1.732 \times Volts\ (Line\text{-}To\text{-}Line) \times Amps}{1000}$$

**2.1.17** $R_s$ — Volume of gas in solution at any pressure up to bubble point pressure (SCF/BBL). Bubble point pressure is defined as the pressure above which all gas is in solution.

$$R_s = Y_g \left[\frac{P}{18}\left(\frac{10^{0.0125\,(API^\circ)}}{10^{0.00091t}}\right)\right]^{\frac{1}{0.83}}$$

Where: Y = Sp. Gr. of Gas
P = Bubble Point Pressure (PSI)
API = API Gravity of Oil (°API)
t = Fluid Temperature (°F)

**2.1.18** Bo — Shrinkage Factor (formation volume factor). A multiplier applied to oil stock tank barrels to determine volume occupied in formation. Can be calculated.

$$Bo = 0.972 + \left[0.000147F\right]^{1.175}$$

Where:

$$F = R_s\left[\frac{(Y_g)}{Y_o}\right]^{0.5} + 1.25t$$

$Y_o$ = Sp. Gr. of Oil.

**2.1.19** $B_g$ or Formation Gas Volume Factor — A multiplier applied to the volume of free gas existing at a given condition to determine the volume occupied in the formation of free gas.

$$B_g = .0283\left[\frac{ZT}{P}\right] \text{Ft.}^3\text{/SCF } \underline{\text{or}}\ .0283 \times$$

$$\left[\frac{1728 \times 1000}{42} \ \frac{\ }{231} \ \frac{ZT}{P}\right] \text{bbls/MSCF}$$

$$B_g = 5.04\,\frac{ZT}{P} \text{ BBLS/mcf}$$

Where: Z = Gas Compressibility Factor
T = Temperature °R
P = Pressure PSIA

**2.1.20** Vo = Volume of oil at PIP bbls.

**2.1.21** Vg = Volume of free gas at PIP, bbls.

**2.1.22** Vw = Volume of water at PIP, bbls.

**2.1.23** Vt = Total volume of mixture (Vo + Vg + Vw) at PIP, bbls.

**2.1.24** Vg/Vt — Gas volume to total volume ratio.

## 2.2 DATA AND CHARTS

**2.2.1 Pump Performance Curves** (Fig. 1):

a. Show the Discharge Head, Brake Horsepower and Efficiency as a function of Flow Rate for one stage of each pump type. Some curves may be set for 100 stages.

b. Are based on fresh water (S.G. = 1.0).

c. Give a Recommended Capacity Range for pump operation.

d. Are commonly available for both 50 Hertz (Hz) and 60 Hz motor operation.

**2.2.2 Fluid Friction Chart** (Fig. 2):

a. Shows fluid friction loss as a function of tubing size and flow rate.

b. Is shown for water for a pipe roughness of C = 120. If a viscous fluid is involved, proper corrections must be made (see Section 2.2.3).

NOTE: *A pipe roughness of C = 120 is used due to data availability and its universal use with non-viscous fluids.*

**2.2.3 Tubing Friction & Viscosity Correction Charts** (Figs. 3 - 10):

a. It is recommended that viscosity correction be considered for pumped fluids with viscosity greater than 50 SSU.

b. Fig. 3 may be used to determine viscosity (in centipoise) from gas free crude API gravity.

c. Figure 4 may be used to determine gas solution for a given API gravity crude oil at pump intake pressure.

d. Figure 5 using gas in solution allows the determination of the corrected crude oil viscosity centipoise.

e. Figure 6 may be used to convert viscosity from centipoise to SSU.

f. Figure 7 provides the viscosity correction factor considering percent water cut and type of emulsion. Where water is the primary phase it wets the wall of the tubing and the viscosity will be dependent principally on the water properties.

g. Figures 8, 9 and 10 give the viscous flow head loss due to fluid friction in various tubing sizes, fluid flow rates and fluid viscosities. (Pipe roughness C = 130).

NOTE: *A pipe roughness of C = 130 is used due to data availability. Variance from a C = 120 is insignificant.*

**2.2.4 Pump Performance Correction Chart** (Fig. 11):

a. It is recommended that viscosity correction should be considered to correct Pump Performance when the viscosity of pumped fluids is greater than 50 SSU.

b. Chart shown in Fig. 11 is to be used as general guideline only, since these values may change due to specific pump design and pump size. Equipment manufacturer should be consulted for proper correction factor.

**2.2.5 Voltage Loss Chart** (Fig. 12):

a. This chart gives the voltage loss per 1000 ft. for various sizes of power cable at 68°F. A correction factor should be used to determine the additional voltage loss at well operating temperature.

**2.2.6 Well Temperature vs. Current Charts** (Figs. 13 - 16):

These charts are used to determine insulation temperatures when considering well temperature at bottom and current through cable.

**2.2.7 Pump Volume Factor** (Figs. 17 - 18):

a. These graphs allow calculation of the Pump Volume Factor (PVF) of a bubble point liquid knowing amount of gas in solution at Pump Intake Pressure (PIP) (Fig. 4), gas gravity, API gravity of the crude oil, and Bottom Hole Temperature (BHT).

b. These graphs assume that all free gas is produced through the casing annulus.

**2.2.8 Motor Annular Fluid Velocity** (Fig. 19):

a. This chart allows the determination of fluid flow velocity by the motor for various casing sizes.

## SECTION 3
## ELECTRIC SUBMERSIBLE PUMP COMPONENT DESCRIPTION

**3.1 Subsurface Equipment** (Fig. 20):

**3.1.1 Motor**

a. The motor is the driving force (prime mover) which turns the pump, and is a two pole, three-phase, squirrel cage induction type that runs at a relatively constant speed of 3500 RPM at 60 Hertz frequency power.

b. The motor is filled with a highly refined mineral oil or synthetic oil that must provide dielectric strength, lubrication for bearings, and good thermal conductivity. The nonconductive oil in the motor housing lubricates the motor bearings and transfers heat generated in the motor to the motor housing.

c. Heat from the motor housing is dissipated by the well fluids moving past the exterior surface of the motor. Therefore, a pumping unit motor should never be set below the point of fluid entry unless some means of directing the fluid by the motor is utilized. It is generally accepted practice to maintain a minimum fluid velocity of one ft/second to insure proper motor cooling.

d. Tandem motors are single motors electrically and mechanically connected in series to provide larger horsepower.

e. The motor is fitted with a thrust bearing which makes the motor suitable for rotation in one direction only as designed by the manufacturer.

**3.1.2 Motor Seal Chamber**

The motor seal chamber (or motor protector) in general performs the following five basic functions:

a. To connect pump housing to the motor housing and to connect the drive shaft of the motor to the pump shaft.

b. To house the pump thrust bearing to carry the axial thrust developed by the pump.

c. To prevent the entry of well fluid into the motor.

d. To equalize the pressure inside the motor with the well bore pressure and thus to eliminate the pressure difference across shaft seals.

e. To compensate for the expansion and contraction of motor oil due to heating and cooling of motor when the unit is running or shut down.

**3.1.3 Intake Section or Gas Separator**

The intake section plays the role of a suction manifold feeding the well fluid to the pump. Depending on well conditions, it can be in the form of a simple adapter with inlet holes or in the form of a gas separator. The gas separator is an aid in preventing gas lock and provides more efficient pumping of gassy wells. Their effectiveness varies with each design and produced volumes.

**3.1.4 Pump**

a. The submersible pump is a multi-staged centrifugal type. Each stage consists of a rotating impeller and a stationary diffuser. The type and size of stage used determines the volume of fluid to be produced. The number of stages determines the total head generated and when multiplied by the horsepower per stage and specific gravity, the motor horsepower required can be determined.

b. Pumps are manufactured in a broad range of capacities.

c. Tandem pumps are two or more single pumps which are mechanically and hydraulically connected in series to provide the total pump discharge head required for the application.

**3.1.5 Motor Lead Extension**

The motor lead extension is a special low profile (flat) power cable extending from the pothead on the motor to above the end of the pump where it connects with the power cable. A low profile cable is usually needed in this area due to limited clearance between the pump housing and the well casing.

**3.1.6 Motor Lead Extension Guards**

The guards provide mechanical protection for the motor lead extension.

**3.1.7 Power Cable**

The power cable is a special three conductor cable which extends from the top of the pump to the wellhead, held to tubing by cable bands. It is available in a range of conductor sizes, insulation types and construction to accommodate well conditions and temperatures. Economic consideration governed by the cost of power and initial cost of cable must be evaluated.

**3.1.8 Check Valves and Bleeder or Drain Valves**

a. If a check valve is installed, it should be located a minimum of 6 to 8 joints above the pump to allow gas to be purged from pump on start-up.

b. If a check valve is installed, a bleeder or drain valve should also be installed. It should be located one joint above the check valve.

c. For larger horsepower units (above 250 HP) regardless of setting depth, and low capacity units (less than 600 B/D) set deep (with static fluid level below 7000 feet), it is recommended that the tubing be filled before start-up. This means these installations must be equipped with tubing Check Valves and drain valves.

**3.1.9 Cable Bands**

a. Cable bands are used to secure the Motor Lead Cable and Power Cable to the pump and tubing, respectively.

b. Bands are available in carbon steel, stainless steel, and monel.

c. Bands are available in 22" to 42" lengths or as continuous banding material.

**3.2 SURFACE EQUIPMENT (Fig. 21):**

**3.2.1 Wellhead**

a. The wellhead assembly provides a tubing support and allows the power cable to pass from the surface into the well bore.

b. It must be provided with a wellhead feed through mandrel or pack-off method which provides a positive seal around the cable.

c. Wellheads and cable pack-offs are available in various pressure ratings and hanging load capacities. This must be considered when selection is made, including any local safety codes or other requirements.

d. All valves exposed to pump pressure must be rated at or above full pump discharge pressure.

**3.2.2 Junction Box (Vent Box)**

a. A vented junction box provides a point to connect the surface cable from the motor control panel to the power cable from the well and provides a vent to the atmosphere for any gas which migrates through the power cable in oil wells.

**3.2.3 Surface Cable**

a. Surface cable connects the junction box to the motor control panel and the motor control panel to the secondary side of the transformers.

**3.2.4 Motor Control Panel**

a. A motor control panel is a combination motor starter, overload-underload protective device and recording instrument. Surge arrestors (Lightning Arrestors) should be included in the panel.

b. They are available in various voltage and amperage ratings with additional controls according to power requirements.

**3.2.5 Transformers**

a. The purpose of the transformer is to provide correct surface voltage for proper motor operation by changing electric power from a high voltage to a low voltage in the case of a step-down transformer or low to high in case of step-up transformer.

b. Transformer selection is based on power rating in KVA, primary voltage, and tap arrangement.

## SECTION 4
## WELL DATA SHEET
## (Fig. 22)

**4.1** The proper selection of a particular pump type and size for a given application is very important and requires detailed information on well completion, reservoir data and production data and history.

**4.1.1 Required Data**

a. The Well Data Sheet (Fig. 22) provides a form for collecting necessary data.

b. This form should be filled out as completely as possible, making certain that all data provided is accurate, since this data will determine pump selection and sizing.

c. Data lines preceded with an asterisk (*) indicate data that must be provided to allow pump sizing and selection.

## SECTION 5
## PUMP AND SYSTEM SIZING

**5.1 Example Problem No. 1** — Water and Oil Production with no Gas. Problem nomenclature:

$$[\text{definition term}]\ \frac{\text{Actual Value}}{(\text{reference number})}$$

**5.1.1** The following exhibit sheets provide data and information required for Example Problem No. 1.

a. Exhibit 1.1 — Well Data Sheet

b. Exhibit 1.2 — Pump Performance Curve

c. Exhibit 1.3 — Pump Specifications

d. Exhibit 1.4 — Motor Specifications

e. Exhibit 1.5 — Motor Seal Chamber Specifications

f. Exhibit 1.6 — Motor Control Panel and Accessories Specifications

g. Exhibit 1.7 — Transformer Specifications

h. Exhibit 1.8 — Tubing Head Specification

i. Exhibit 1.9 — Cable Specifications

j. Exhibit 1.10 — Equipment and Cable Size Information

k. Exhibit 1.11 — Flat Cable and Surface Cable Specifications

l. Exhibit 1.12 — Downhole Equipment with Offset Tubing Head.

**5.1.2** Unless otherwise specified, data used in sizing calculations comes from Well Data Sheet (Exhibit 1.1).

**a. Well Fluid Composite Specific Gravity**

$$1)\ \begin{bmatrix}\text{Water Cut}\end{bmatrix}\ \underline{0.80} \times \begin{bmatrix}\text{Water Sp. Gr.}\end{bmatrix}\ \underline{1.060} = \underset{(1)}{\underline{0.848}}\ \begin{bmatrix}\text{Water Phase}\\ \text{Sp. Gr.}\end{bmatrix}$$

$$2)\ \begin{bmatrix}\text{Oil Cut}\end{bmatrix}\ \underline{0.20} \times \begin{bmatrix}\text{Oil Sp. Gr.}\end{bmatrix}\ \underline{0.840} = \underset{(2)}{\underline{0.168}}\ \begin{bmatrix}\text{Oil Phase}\\ \text{Sp. Gr.}\end{bmatrix}$$

$$3)\ \begin{bmatrix}\text{Water Phase}\end{bmatrix}\ \underset{(1)}{\underline{0.848}} + \begin{bmatrix}\text{Oil Phase}\end{bmatrix}\ \underset{(2)}{\underline{0.168}} = \underset{(3)}{\underline{1.016}}\ \begin{bmatrix}\text{Well Fluid}\\ \text{Composite}\\ \text{Sp. Gr.}\end{bmatrix}$$

**b. Well Fluid Composite Gradient**

$$1)\ \begin{bmatrix}\text{Well Fluid}\\ \text{Composite}\\ \text{Sp. Gr.}\end{bmatrix}\ \underset{(3)}{\underline{1.016}} \times \begin{bmatrix}\text{Fresh Water}\\ \text{Pressure}\\ \text{Gradient}\end{bmatrix}\ \underline{0.433}\ \text{PSI/Ft.} = \underset{(4)}{\underline{0.440}}\ \text{PSI/Ft.}\ \begin{bmatrix}\text{Well Fluid}\\ \text{Composite}\\ \text{Gradient}\end{bmatrix}$$

**c. Fluid Over Pump (FOP)**

$$1)\ \begin{bmatrix}\text{Pump Intake}\\ \text{Pressure}\end{bmatrix}\ \underline{500\ \text{PSI}} \div \begin{bmatrix}\text{Well Fluid}\\ \text{Composite}\\ \text{Gradient}\end{bmatrix}\ \underset{(4)}{\underline{0.440\ \text{PSI/Ft.}}} = \underset{(5)}{\underline{1136\ \text{Ft.}}}\ \begin{bmatrix}\text{FOP}\end{bmatrix}$$

**d. Vertical Lift $H_D$**

$$1)\ \begin{bmatrix}\text{Pump Vertical}\\ \text{Setting Depth-}V_D\end{bmatrix}\ \underline{9000\ \text{Ft.}} - \begin{bmatrix}\text{Fluid Over}\\ \text{Pump-FOP}\end{bmatrix}\ \underset{(5)}{\underline{1136\ \text{Ft.}}} = \underset{(6)}{\underline{7864\ \text{Ft.}}}\ \begin{bmatrix}\text{Vertical}\\ \text{Lift-}H_D\end{bmatrix}$$

**e. Tubing Friction Loss - $H_F$ (Ref. Fig. 2)**

$$1)\ \begin{bmatrix}\text{Gross}\\ \text{Production}\\ \text{Rate (B/D)}\end{bmatrix}\ \underline{1100\ \text{B/D}}\ \text{in}\ \begin{bmatrix}\text{Nom.}\\ \text{Tubing}\\ \text{Size}\end{bmatrix}\ 2\tfrac{3}{8}'' = \underset{(7)}{\underline{33\ \text{Ft./1000}}}\ \begin{bmatrix}\text{Friction}\\ \text{Loss Per}\\ \text{1000 Ft.}\end{bmatrix}$$

$$2)\ \begin{bmatrix}\text{Friction}\\ \text{Loss Per}\\ \text{1000 Ft.}\end{bmatrix}\ \underset{(7)}{\underline{33\ \text{Ft./1000}}} \times \begin{bmatrix}\text{Tubing}\\ \text{Length}\end{bmatrix}\ \underline{9000} = \underset{(8)}{\underline{297\ \text{Ft.}}}\ \begin{bmatrix}\text{Tubing}\\ \text{Friction}\\ \text{Loss-}H_F\end{bmatrix}$$

**f. Producing Tubing Head - $H_T$ (Ft.)**

$$1)\ \begin{bmatrix}\text{Producing}\\ \text{Tubing}\\ \text{Pressure}\end{bmatrix}\ \underline{100\ \text{PSI}} \div \begin{bmatrix}\text{Composite}\\ \text{Gradient}\end{bmatrix}\ \underset{(4)}{\underline{0.440}} = \underset{(9)}{\underline{227\ \text{Ft.}}}\ \begin{bmatrix}\text{Producing}\\ \text{Tubing}\\ \text{Head-}H_T\end{bmatrix}$$

**g. Pump Total Dynamic Head (Ft.)**

$$\begin{bmatrix}\text{Vertical}\\ \text{Lift-}H_D\end{bmatrix}\ \underset{(6)}{\underline{7864\ \text{Ft.}}} + \begin{bmatrix}\text{Tubing}\\ \text{Friction}\\ \text{Loss-}H_F\end{bmatrix}\ \underset{(8)}{\underline{297\ \text{Ft.}}} + \begin{bmatrix}\text{Producing}\\ \text{Tubing}\\ \text{Head-}H_T\end{bmatrix}\ \underset{(9)}{\underline{227\ \text{Ft.}}} = \underset{(10)}{\underline{8388\ \text{Ft.}}}\ \begin{bmatrix}\text{Total}\\ \text{Dynamic}\\ \text{Head TDH}\end{bmatrix}$$

**h. Now Select Pump for 1100 B/D to Fit in 5½″ Casing**

1) A review of the performance (Head-capacity) curves results in a choice of pump type A (Exhibit 1.2), which shows maximum efficiency (66%) at required capacity (1100 B/D).

**i. Determine Lift (Head) Per Stage**

1) Referring to Exhibit 1.2 read vertically from 1100 B/D on the capacity scale to the head-capacity curve intersection.

2) From intersection read horizontally to left to head in feet per stage = $\underset{(11)}{\underline{29.0\text{ Ft.}}}$

**j. Determine Horsepower Required Per Stages**

1) Referring to Exhibit 1.2 read vertically from 1100 B/D on the capacity scale to the Brake Horsepower Curve intersection. NOTE: This curve is for a specific gravity of 1.0.

2) From intersection read horizontally to right to Brake Horsepower per stage of 0.35 H.P. While the horsepower per stage at the required capacity (0.35 HP/Stage) at 1100 B/D can be used, it is more common to use the maximum horsepower per stage factor. For the Type A pump stage = $\underset{(12)}{\underline{0.38\text{ HP}}}$/Stage

CAUTION: *Some performance curves are for single stages and others for 100 stages.*

**k. Number of Pump Stages Required**

1) $\begin{bmatrix}\text{Total}\\ \text{Dynamic}\\ \text{Head (TDH)}\end{bmatrix} \underset{(10)}{\underline{8388\text{ Ft.}}} \div \begin{bmatrix}\text{Head Per}\\ \text{Stage}\end{bmatrix}$

$\underset{(11)}{\underline{29.0\text{ Ft./Stage}}} = \underset{(13)}{\underline{289}}\text{ Stages}$

2) Refer to Exhibit 1.3, Pump Specifications, to find closest number of stages in a standard pump housing. For the Type A pump $\underset{(14)}{\underline{288}}$ stages would be selected. It is Housing No. 17T, is 29.2 feet long and weighs 863 pounds.

**l. Motor Horsepower Required**

1) Determine pump chamber horsepower.

$\begin{bmatrix}\text{No. of}\\ \text{Pump}\\ \text{Stages}\end{bmatrix} \underset{(14)}{\underline{288}} \times \begin{bmatrix}\text{HP}\\ \text{Per}\\ \text{Stage}\end{bmatrix} \underset{(12)}{\underline{0.38\text{ HP/Stage}}}$

$\times \begin{bmatrix}\text{Water*}\\ \text{Sp. Gr.}\end{bmatrix} \underline{1.060} = 116\text{ H.P.}$

(*For high water cut wells use produced water specific gravity. For low water cut wells use composite well fluid specific gravity.)

2) Referring to motor seal section specifications (Exhibit 1.5) determine horsepower required by motor seal chamber. It is 2.5 H.P.

3) Determine motor horsepower required by adding pump brake horsepower, motor seal section horsepower and gas separator (if used) horsepower.

$[116 + 2.5 + 0 = \underset{(15)}{118.5}]$

4) Referring to Motor Rating Specifications (Exhibit 1.4) the closest motor size is $\underset{(16)}{\underline{120}}$ H.P. It is 29.5 feet long and weighs 1430 pounds.

5) Check fluid flow velocity for motor cooling (Fig. 19). Since this is a 4½″ O.D. motor in 5½″ casing, the velocity at 1100 B/D is well above the 1.0 ft./sec. minimum recommended velocity.

6) A choice of two motors is available:

a) 1150 V. and 67 A.

b) $\underset{(17)}{\underline{2280\text{ V.}}}$ and $\underset{(18)}{\underline{34\text{ A.}}}$

In general, the higher voltage, lower amperage motor is the better choice in most installations, since it minimizes power cable losses. The choice of motor voltage may be based on a number of factors including well depth, casing size, horsepower size, cable size required, initial equipment cost and operating cost. Also, the power distribution voltage may be a factor.

**m. Motor Seal Chamber**

1) Referring to Exhibit 1.5 the Model 1 motor seal chamber is for use with single motors for 5½″ casing. It is 4½ feet long and weighs 110 pounds.

**n. Power Cable Length**

1) The power cable length is the measured pump setting depth (MD) plus 100 feet.

2) For this problem:

$\begin{bmatrix}\text{Measured}\\ \text{Depth-MD}\end{bmatrix} 9000\text{ Ft.} + 100\text{ Ft.} =$

$9100\text{ Ft.} \begin{bmatrix}\text{Power}\\ \text{Cable}\\ \text{Length}\end{bmatrix}$

**o. Power Cable Size Selection**

1) Using motor name plate voltage (2280V.) calculate recommended cable voltage drop.

$$\underset{(17)}{\underline{2280V.}} \times \left[\begin{array}{l}\text{Voltage}\\ \text{Drop}\\ \text{Factor}\end{array}\right] \underset{(18)}{\underline{0.05^*}} =$$

$$\underset{(19)}{\underline{114V.}} \left[\begin{array}{l}\text{Cable}\\ \text{Voltage}\\ \text{Drop}\end{array}\right]$$

2) Now determine voltage drop per 1000 ft.

$$\left[\begin{array}{l}\text{Cable}\\ \text{Voltage}\\ \text{Drop}\end{array}\right] \underset{(19)}{\underline{114V.}} \div \left[\begin{array}{l}\text{Cable}\\ \text{Length}\end{array}\right] \frac{9100\text{ Ft.}}{1000} =$$

$$\underset{(20)}{\underline{12.5V./1000\text{ Ft.}}} \left[\begin{array}{l}\text{Recommended}\\ \text{Cable}\\ \text{Voltage}\\ \text{Drop/}\\ \text{1000 Ft.}\end{array}\right]$$

3) Reference Fig. 12 (Voltage Drop Chart) for operating Bottom Hole temperature (190°F), find the conductor Voltage Drop Correction factor $= \underset{(12)}{\underline{1.267}}$

4) Now divide the

$$\left[\begin{array}{l}\text{Recommended}\\ \text{Cable Voltage}\\ \text{Drop/1000 Ft.}\end{array}\right] \underset{(20)}{\underline{12.5V.}} \div \left[\begin{array}{l}\text{Voltage}\\ \text{Drop}\\ \text{Correction}\\ \text{Factor}\end{array}\right]$$

$$\underset{(21)}{\underline{1.267}} = \underset{(22)}{\underline{9.9}}/1000\text{ Ft.}$$

Now enter Fig. 12 at 9.9V./1000 Ft. on left hand scale and read horizontally to the right to motor amperage (34 amps) and choose cable size at or below this point. For 9.9V./1000 Ft. and 34 amps this would be a $\underset{(23)}{\underline{\text{\#2 Copper Cable}}}$, which results in an actual voltage drop of 9V./1000 Ft.

5) Check for motor start-up.

a) Determine actual operating motor voltage drop

$$9.0V./1000\text{ Ft.} \times 9100\text{ Ft.} \times 1.267$$

$$\left[\begin{array}{l}\text{Cable}\\ \text{Temp}\\ \text{Factor}\end{array}\right] = 104V. \left[\begin{array}{l}\text{Operating}\\ \text{Voltage}\\ \text{Drop}\end{array}\right]$$

b. Determine in-rush voltage drop (4.0 factor considers sag in primary system and other system losses)

$$104V. \times \underline{4.0} \left[\begin{array}{l}\text{In Rush}\\ \text{Voltage}\\ \text{Drop Factor}\end{array}\right]$$

$$= 416V. \left[\begin{array}{l}\text{In Rush}\\ \text{Voltage}\\ \text{Drop}\end{array}\right]$$

c) Determine motor terminal start-up voltage.

$$2280V. - 416V. = 1864V. \left[\begin{array}{l}\text{Start-up}\\ \text{Motor}\\ \text{Terminal}\\ \text{Voltage}\end{array}\right]$$

d) Calculate start-up voltage at motor as percent of motor name plate voltage.

$$\frac{1864V.}{2280V.} \times 100 = 81.8\%$$

Since this is greater than 50% of motor name plate voltage motor start-up should not be a problem. The 50% minimum requirement and the 4.0 In Rush voltage drop factor are determined by operating experience. Some tests have indicated higher in-rush currents than 4.0. Manufacturer should be contacted for specific recommendations.

*NOTE: *The 5% voltage drop is based on NEC Article 215.2, and results in a reduced power loss and extended power cable life.*

*Other limiting methods such as 30V/1000 ft. may be used to determine voltage loss in the power cable. The amount of voltage drop allowed must consider the ability to start the motor.*

**p. Power Cable Clearance**

1) Having selected the power cable size required $(\underset{(23)}{\underline{\text{\#2 Copper Cable}}})$, it is necessary to be certain that there is sufficient clearance for the power cable and equipment in the well bore.

2) The following power cable clearance calculation assumes that an offset pump discharge tubing head is used on the pump. Therefore, the well

diameter (casing I.D.) must be greater than the largest of the following:

a) $A + B$

b) $\left(\frac{E}{2} - D\right) + \frac{A}{2} + B$

c) $\left(\frac{C}{2} - D\right) + \frac{A}{2} + B$

d) $\frac{C}{2} + \frac{E}{2} + F + G$

e) $\frac{H}{2} + \frac{E}{2} + F + G$

Where:

A = Tubing Coupling Diameter

B = Power Cable Diameter

C = Pump Diameter*

D = Unit Centerline/Discharge Head Centerline Offset Dimension

E = Motor Diameter*

F = Motor Lead Extension Thickness

G = Band Thickness

H = Motor Seal Chamber

*Must include special coating thickness if used.

**Therefore for this problem:**

A = 3.063″ (2⅞ EU Coupling O.D.)

B = 1.320″ (from Exhibit 1.10)

C = 4.000″ (from Exhibit 1.10)

D = 0.220″ (from Exhibit 1.12)

E = 4.500″ (from Exhibit 1.10)

F = 0.450″ (from Exhibit 1.11)

G = 0.030

H = 4.00″ (from Exhibit 1.10)

**Then making calculations:**

a) $A + B = 3.063'' + 1.320'' = \underline{4.383''}$ (24)

b) $\left(\frac{E}{2} - D\right) + \frac{A}{2} + B = \frac{4.500}{2} - 0.220 + \frac{3.063''}{2} + 1.320'' = \underline{4.882''}$ (25)

c) $\left(\frac{C}{2} - D\right) + \frac{A}{2} + B = \frac{4.000}{2} - 0.220 + \frac{3.063''}{2} + 1.320'' = \underline{4.632''}$ (26)

d) $\frac{C}{2} + \frac{E}{2} + F + G = \frac{4.000}{2} + \frac{4.500}{2} + 0.450'' + 0.030'' = 4.730''$

e) $\frac{H}{2} + \frac{E}{2} + F + G = \frac{4.00}{2} + \frac{4.50}{2} + 0.450'' + 0.03'' = 4.73$

Therefore b) is largest = 4.882″.

Then comparing it with the casing I.D. for clearance.

Casing I.D. (5½ × 17#) = 4.892″

Equipment "Diameter" b) = −4.882

$\underline{0.010}$ (27)

Therefore the equipment and power cable "bundle" will go in the casing. However, extreme care should be taken due to this small clearance.

NOTE: *Exhibit 1.10 has a table for maximum cable/equipment size combinations.*

**q. Power Cable Insulation**

1) Select power cable insulation based on well bore temperature at pump setting depth, motor current, and well bore environment. Using Fig. 14 (for #2 power cable) find the well bore temperature (190°F) on left hand scale, and read horizontally to motor current (34 amps) intersection. This gives a conductor temperature of 200°F.

2) Since conductor temperature is 200°F select the proper power cable insulation from cable supplier's information.

CAUTION: *Some cable insulations can deteriorate when coming into contact with some types of corrosion inhibitors.*

**r. Motor Lead Extension**

1) Cable size of the motor lead extension and motor potlead size is determined by the annular space available. Choose the largest size available that will provide acceptable clearance in the well bore.

2) Next, select the type of armor that is appropriate for the well bore conditions. Available materials may include galvanized steel, phosphur bronze, and monel. Phosphur bronze armor will be chosen since this well has no corrosion problem.

3) The motor lead extension length is determined by making it reach at least 5 feet beyond the pump discharge head. This is calculated as follows:

   (a) Pump Length ........... 29.2 Ft.

   (b) Motor Seal Chamber...... 4.5 Ft.

   (c) Length Above Pump..... +5.0 Ft.

   (d) Additional Accessory Equipment ............ 5.0 Ft.

   (e) Motor Lead Extension Length ............... 43.7 Ft. (29)

   Referring to Exhibit 1.11 a 60 foot motor lead extension is available and is chosen for this installation.

4) A motor lead extension cable guard should be chosen to go with this.

**s. Cable Bands**

1) Stainless steel bands were requested by user so these will be provided.

2) One 25 count bundle of 30" bands is required for securing the motor lead extension.

3) Two 22" bands per tubing joints are required or:

$$\frac{9000\text{ Ft.}}{30\text{ Ft./Joint}} \times 2\text{ Bands/Joint} = \frac{600\text{ Bands}}{(30)}$$

**t. Wellhead**

1) Select a wellhead sufficient to carry the weight of the tubing, equipment and fluid.

   (a) Motor............. = 1430 lbs.

   (b) Motor Seal Chamber = 110 lbs.

   (c) Pump............. = 863 lbs.

   (d) Tubing 4.7 lb/ft. × 9000 ft. ......... = 42,300 lbs.

   (e) Power Cable 1.62 lb/ft. × 9000 ft. ......... = 14,580 lbs.

   (f) Motor Lead 1.70 lb/ft. × 40 ft. ................... = 70

   (g) Cable Bands 15 lb/100 × 600 ..................... = 90

   (h) Fluid = 1.060 sp. gr. × 8.34 lb/gal × 0.1626 gal/ft. × 9000 ft. ............. = 12,940

   (i) Total Weight on Tubing Head ........... = 72,383 lbs. (31)

2) Based on this total weight and referring to Exhibit 1.8, the Type B tubing head for 5½" O.D. casing size by 2⅜" tubing size with a pack-off for #2 round cable is chosen.

3) 288 stages × 29 ft./stage × 0.440 = 3675 psi. Therefore all valves and fittings on the tubing must be rated greater than 3675 psi.

**u. Motor Control Panel and Junction Box**

1) Calculate surface "no load" voltage:

   (a) Motor Name Plate Voltage = 2280V. (17)

   (b) Cable Voltage Drop = +104V. (19)

   (c) Surface Full Load Voltage 2384V. (32)

   (d) Transformer Drop Factor (3%) X1.03

   (e) Surface "No Load" Voltage 2456V. (33)

2) Referring to Exhibit 1.6 a motor control panel is selected which has adequate voltage and amp rating to accommodate system voltage and current (2456 V. and 34 amps). Therefore, the Size D3 MCP is selected. Various control options are available. Lightning arrestors should be specified if applicable.

3) A junction box should be specified for the installation.

**v. Transformers**

1) The transformer rating in KVA is:

$$\begin{bmatrix}\text{Surface}\\ \text{Full}\\ \text{Load}\\ \text{Voltage}\end{bmatrix} \frac{2384\text{ V.}}{(32)} \times \begin{bmatrix}\text{Motor}\\ \text{Amps}\end{bmatrix} \frac{34\text{ A.}}{(18)} \times \frac{1.732}{1000} = \frac{140\text{ KVA}}{(32)}$$

2) For 3 single phase transformers:

$$\frac{140\ \text{KVA}}{(34)} \div \left[\frac{\text{No. of}}{\text{Transformers}}\right] \frac{3}{} = \frac{47\ \text{KVA}}{(35)}$$

Therefore, use three 50 KVA transformers. Referring to Exhibit 1.7 for single phase transformers the 50 KVA for a primary voltage of 14,400/24,940 should be selected. As the note indicates, additional secondary voltages can be obtained by WYE connecting the secondary. This is how the 2400 V. system voltage is obtained.

**5.2 Example Problem No. 2** — Water and Oil Production with Gas

**5.2.1** The following exhibit sheets provide data and information required for Example Problem No. 2.

**a.** Exhibit 2.1 — Well Data Sheet.

**5.2.2** Unless otherwise specified, data used in sizing calculations comes from the Well Data Sheet (Exhibit 2.1).

**a.** From Figure 17 determine gas solution ($R_s$) at 500 PSI PIP = 83 ft.$^3$/bbl.

**b.** Enter Figure 18 at 83 ft.$^3$/bbl. ($R_s$ @ 500 PSI PIP) and determine formation volume factor ($B_o$) = 1.1 bbl/bbl. STO.

**c.** Determine formation gas volume factor Bg at 500 PSI PIP as follows:

$$Bg = \left[.0283\,\frac{ZT}{P}\right] \text{ft.}^3/\text{scf or } \left[.0283\,\frac{ZT}{P}\right] \times$$

$$\left[\frac{1728 \times 1000}{231 \quad 42}\right] = 5.04\,\frac{ZT}{P}\ \text{bbl/scf}$$

$$Bg = \frac{5.04 \times 0.85 \times 650}{515} = 5.4\ \text{bbl/MSCF}$$

Use gas compressibility factor (Z) = .85 (Note Z varies with gas Sp. gr., pressure and temperature. Z = .85 is used as an average).

**d.** Determine if gas separator is required, that is, if free gas at PIP exceeds 10% by volume:

**(1)** Total gas in solution at bubble point = B/D oil × $R_s$ = $\frac{220 \times 440}{1000}$ = 96.8 Mcf day*

**(2)** Total gas still in solution at PIP = $R_s$ × B/D oil = $\frac{220 \times 83}{1000}$ = 18.26 Mcf day

**(3)** Gas liberated or Free gas = 96.8 - 18.26 = 78.54 Mcf day.*

*NOTE: *If GOR is used instead of $R_s$ this number is slightly larger.*

**(4)** Volume of oil = Vo = BOPD @ PIP × $B_o$ = 220 × 1.1 = 242 B/D
Volume of gas = Freegas × $B_g$ = 78.54 × 5.4 = 424 B/D
Volume of water = $V_w$ = given = 880 B/D
Vt = 1546 B/D

$$\frac{Vg}{Vt} = \frac{424 \times 100}{1546} = 27\%$$ (27% > 10% therefore a suitable gas separator is required.)

**e.** Assume gas separator is 90% effective and 10% of gas is not separated or Vg = 10%. Therefore, .1 × 424 = 42 entering the pump.

**f.** Therefore the total fluid mixture in B/D entering the pump is:

Vo = 242 B/D
Vg = 42 B/D
Vw = 880 B/D
Vt = 1164 B/D

**g.** The amount of free gas entering the pump as a percent of total fluid is:

$$\frac{Vg}{Vt} = \frac{42 \times 100}{1164} = 3.6\%$$

While gas represents 3.6% by volume of the fluid being pumped it has no significant effect on the well fluid composite specific gravity.

**h.** Now that the total volume of the produced mixture through the pump is known the method of equipment selection is identical to that shown in Example Problem No. 1, Section 5.1.2.

**5.3 Example Problem No. 3** — Water and Viscous Oil Production

**5.3.1** The following exhibit sheets provide data and information required for Example Problem No. 3.

**a.** Exhibit 3.1 — Well Data Sheet.

**5.3.2** Unless otherwise specified, data used in sizing calculations comes from the Well Data Sheet (Exhibit 3.1).

**a.** Using Fig. 3, find the gas free crude viscosity for 15 deg. API crude at 140°F to be 150 Cp.

b. Using Fig. 4, find the gas in solution at 300 PSI (PIP) to be 50 cu. ft./bbl.

c. Using Fig. 5, find the gas-saturated crude oil viscosity for 150 Cp at a 50 cu. ft./bbl. gas in solution ratio to be approximately 70 Cp.

**d. Well Fluid Composite Specific Gravity**

1. Water cut 0.20 × Water Sp. Gr. 1.060

   = .212 (1) [Water Phase Sp. Gr.]

2. Oil Cut 0.80 × Oil Sp. Gr. .966

   = .733 (2) [Oil Phase Sp. Gr.]

3. Water Phase Sp. Gr. .212 (1) + Oil Phase

   Sp. Gr. .773 (2) = .985 [Well Fluid Composite Sp. Gr.]

NOTE: *Well fluid composite contains no free gas by volume.*

e. Using Fig. 6, convert 70 Cp to SSU using an average specific gravity of 0.985. Read 350 SSU.

f. Using Fig. 7, apply the correction factor for a 20.0% water cut. Read 2.0.

g. The 20.0% water cut increases the actual viscosity by a factor of two. Corrected viscosity would be 700 SSU.

h. Refer to Fig. 11 for correction factors. Since installation is in 5.50 O.D. casing, assume 60% efficient pump for required volume.

1. Capacity Factor (Qvis) = 0.805
2. Head Factor (Hvis) = 0.825
3. Horsepower Factor ($bhp_{vis}$) = 1.30

The effects of viscosity on the unit have now been determined and the sizing of the unit can now proceed and the correction factors used where required.

**i. Well Fluid Composite Gradient**

1. [Well Fluid Composite Sp. Gr.] .985 (3) × [Fresh Water Pressure Gradient]

   0.433 = 0.427 (4) [Well Fluid Composite Gradient]

**j. Fluid Over Pump (FOP)**

1. [Pump Intake Pressure] 300 PSI ÷ [Corrected Well Fluid Composite Gradient]

   0.427 (4) = 703 Ft. (5) (FOP)

**k. Vertical Lift — $H_D$**

1. [Pump Vertical Setting Depth] ($V_D$) 5200 Ft.

   - Fluid Over Pump 703 Ft. (5) = 4497 (6) Ft. [Vertical Lift $H_D$]

**l. Vertical Lift Corrected for Viscosity — $H_D$-vis**

1. [Net Lift] 4497 (6) ÷ [Viscosity] 0.825 =

   5451 Ft. (7) [Corrected Vertical Lift]

**m. Tubing Friction Loss — $H_F$ (Ref. Fig. 8)**

For Proper Selection for the Viscosity of the Fluid to be Pumped.

1. [Gross Production Rate] 800 B/D in. [NOM. Tubing Size]

   2⅞″ = 145 (8) Ft./1000 [Friction Loss Per 1000 Ft. At 700 SSU]

2. [Friction Loss Per 1000 Ft.] 145 Ft/1000 (7) × [Tubing Length]

   5200 Ft. = 754 (9) [Tubing Friction Loss-$H_F$]

**n. Producing Tubing Head — $H_T$ (ft.)**

1. [Producing Tubing Pressure] 50 PSI ÷ [Composite Gradient]

   0.427 (4) = 117 Ft. (10) [Producing Tubing Head $H_T$]

2. [Producing Tubing Head $H_T$] $\frac{117\text{ Ft.}}{(10)}$ ÷ [Viscosity Correction Factor]

$\frac{0.825}{}$ = $\frac{142\text{ Ft.}}{(11)}$ [Corrected Tubing Head $H_T$]

**o. Pump Total Dynamic Head (Ft.)**

[Corrected Vertical Lift-$H_D$] $\frac{5451\text{ Ft.}}{(7)}$ + [Friction Loss Per 1000 Ft. At 700 SSU] $\frac{754\text{ Ft.}}{(9)}$ +

[Corrected Tubing Head-$H_T$] $\frac{142\text{ Ft.}}{}$ = $\frac{6347\text{ Ft.}}{}$ [Total Dynamic Head-TDH]

**p. Correct 800 B/D Required Rate for Viscosity @ 700 SSU**

1. [Required STB] $\frac{800\text{ B/D}}{}$ ÷ [Capacity Correction Factor]

$\frac{.805}{}$ = $\frac{994\text{ B/D}}{(13)}$ [Corrected Volume]

**q. Select Pump for 994 B/D to Fit in 5½" Casing**

1. A review of the performance (head-capacity) curves results in a choice of pump Type B (Exhibit 1.2), which shows efficiency (65%) at required capacity (994 B/D).

**r. Determine Lift (Head) Per Stage**

1. Referring to Exhibit 1.2 read vertically from 994 B/D on the capacity scale to the head-capacity curve intersection.
2. From intersection read horizontally to left to head in feet per stage = $\frac{30.0\text{ Ft.}}{(14)}$

**s. Determine Horsepower Required Per Stage**

1. Referring to Exhibit 1.2 read vertically from 994 B/D on the capacity scale to the brake horsepower curve intersection.
2. From intersection read horizontally to right to brake horsepower per stage of 0.28 H.P. maximum horsepower/stage is stage frequently used.

**t. Number of Pump Stages Required**

1. [Total Dynamic Head-TDH] $\frac{6347}{(12)}$ ÷ [Head Per Stage]

$\frac{23.5\text{ Ft./Stage}}{(14)}$ = $\frac{212}{(15)}$

**u. Pump Brake Horsepower Required**

1. [No. of Pump Stages] $\frac{270}{(15)}$ × HP $\frac{0.28\text{ HP/Stage}}{(14)}$ ×

[Horsepower Viscosity] $\frac{1.30}{}$ × [Sp. Gr.] 0.985 = $\frac{103\text{ HP}}{(16)}$

# SECTION 6
# SPECIAL WELL CONDITIONS

**6.1 High Bottom Hole Temperature** — Generally, electric submersible pump installations in wells with bottom hole temperatures up to 200°F are handled as standard installations without special considerations.

**6.1.1** For wells with bottom hole temperatures between 200-250°F special consideration must be given to:

**a. Power Cable** — general cable insulation material temperature limits can be categorized as follows:

| Insulation Material | Well Bore Temp. °F | Conductor Temp. °F |
|---|---|---|
| 1. Polyethylene (PE) Unarmored | 140 | 167 |
| 2. PPE with Nitrile Jacket | 170 | 200 |
| 3. EPR with Nitrile Jacket | 257 | 300 |

These are general guidelines that can be used when evaluating temperature limits of power cable. The cable manufacturer should be consulted to determine specific recommendations for given well conditions.

**b. Electric Submersible Pump Unit** — Most manufacturers' standard equipment is capable of operation to 250°F well bore bottom hole temperature.

**6.1.2** For wells with wellbore bottom hole temperature above 250°F special consideration must be given to:

**a. Power Cable** — Lead sheathed flat power cable should be considered for these applications. There may be other cables also available and the power cable manufacturers should be consulted.

**b. Electric Submersible Pump Unit** — For operation above 250°F it may be necessary for certain modifications to be made to the electric submersible pump unit, such as elastomers, insulating materials and motor oil, or other design and material changes.

**6.2 Corrosion** — If general "oilfield corrosion" is encountered normal corrosion resistant materials and coatings are available to provide protection.

**6.2.1 Power Cable and Banding Material**

a. Galvanized or monel armored cable is available for protection in most corrosive environments.

b. In high $H_2S$ corrosion environments it may be necessary to go to a lead sheathed cable to prevent copper deterioration.

c. Banding materials in stainless steel or monel are available for corrosive environments.

**6.2.2 Electric Submersible Pump Unit**

a. Coatings for corrosion resistance are available and range from a standard paint, special plastic coating, or spray metal coatings such as monel. If special coatings are specified the coating thickness must be included in the clearance calculations (i.e., Section 5.1.2 p.).

b. Some corrosive conditions may require special metallurgy for the housing or other components. The pump manufacturer should be contacted to determine what changes may be required.

c. Anodes are also available for connection to the bottom of the motor.

**6.3 Solids**

**6.3.1** If solids are expected to be a problem in an installation the well bore should be cleaned out prior to installing equipment.

**6.3.2** Special considerations can be made by the pump manufacturer to improve the ability of the pump to handle solids. These may include both material and design changes. The pump manufacturer should be consulted relative to specific applications.

# SECTION 7
# OTHER ELECTRIC SUBMERSIBLE PUMP EQUIPMENT CONSIDERATIONS

**7.1 Electric Submersible Pump variable speed control and soft start.**

**7.1.1 Variable Speed Control** — Allows the Electric Submersible Pump speed to be varied above or below normal operating speed in order to produce the well most effectively. The speed change may be necessary to determine productivity on a new well or to meet changing conditions in an existing well.

**a.** The variable speed drive takes the place of the motor controller and incorporates all of the normal regulations and control usually found in a motor controller.

**b.** By varying pump speed of the centrifugal downhole pump the affinity laws apply as follows:

1) **Flow:** $Q_2 = Q_1 \left(\frac{N_2}{N_1}\right)$

2) **Head:** $H_2 = H_1 \left(\frac{N_2}{N_1}\right)^2$

3) **Brake H.P.:** $BHP_2 = BHP_1 \left(\frac{N_2}{N_1}\right)^3$

Where:

$Q_1$, $H_1$, $BHP_1$, $N_1$ = Initial capacity, Head, Brake Horsepower and speed, respectively.

$Q_2$, $H_2$, $BHP_2$, $N_2$ = New capacity, Head, Brake Horsepower and speed, respectively.

From the above relationships it can be seen that brake horsepower limitations may be quickly reached with increased speed or that insufficient head (shut off) may be reached with reduced speed.

**c.** The sizing and application of the variable speed drive is outside the scope of this RP. Equipment manufacturer should be consulted.

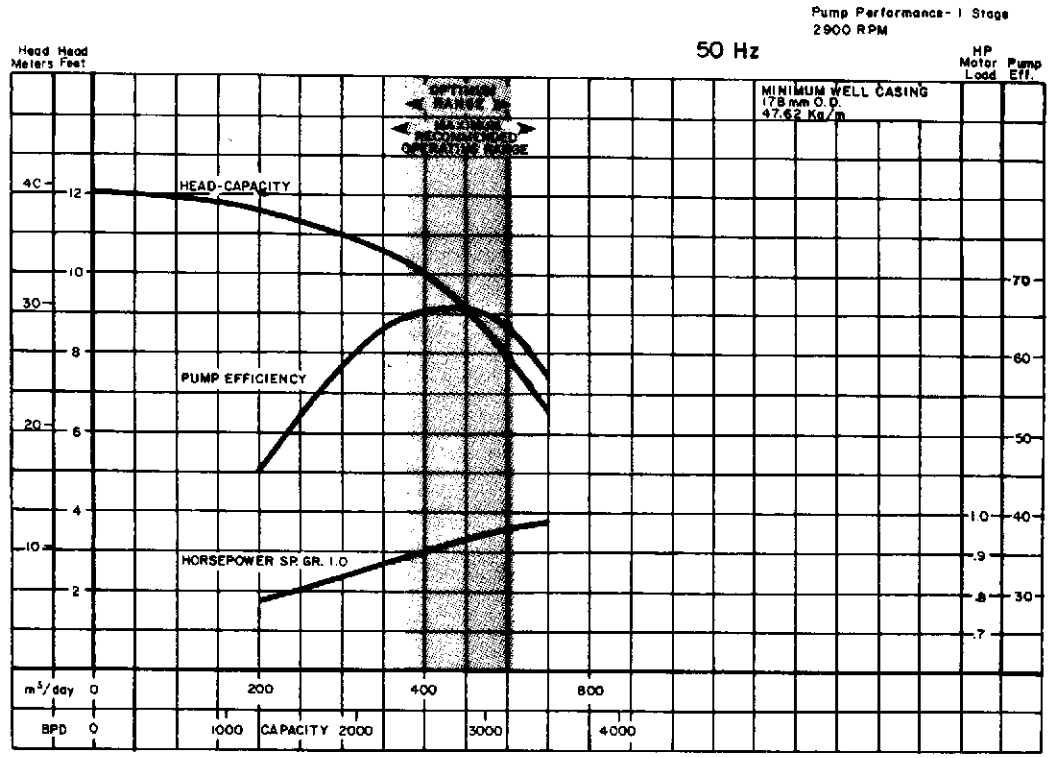
**7.1.2 Soft Start** — Equipment that provides a means of limiting in-rush current and voltage intended to reduce electrical and mechanical stresses at start-up in order to improve unit life.

**a.** Limiting in-rush current reduces power line voltage losses which may be detrimental to other equipment on line.

**b.** Provides less stress on the power cable during start-up.

**c.** Reduces high starting torques that occur on across the line starting, therefore putting lower electrical and mechanical stress on the downhole pump and motor.

**d.** The sizing and application of the soft start unit is outside the scope of this RP. Contact the equipment manufacturer for this information.



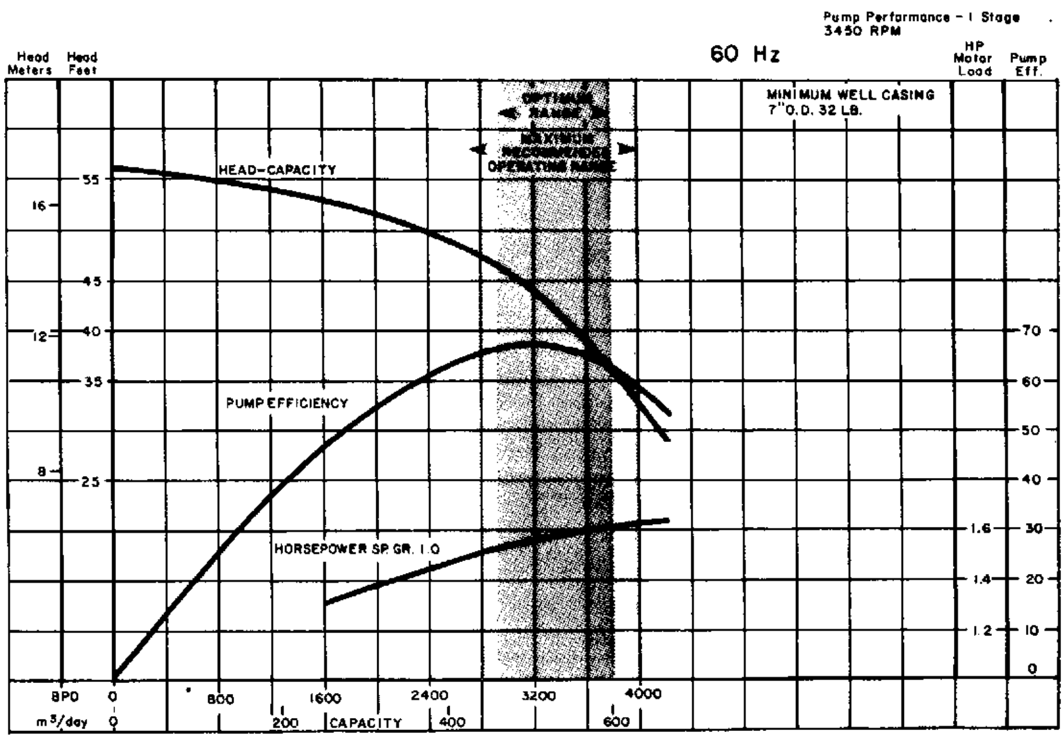




**FIG. 1**
**PUMP PERFORMANCE CURVE**

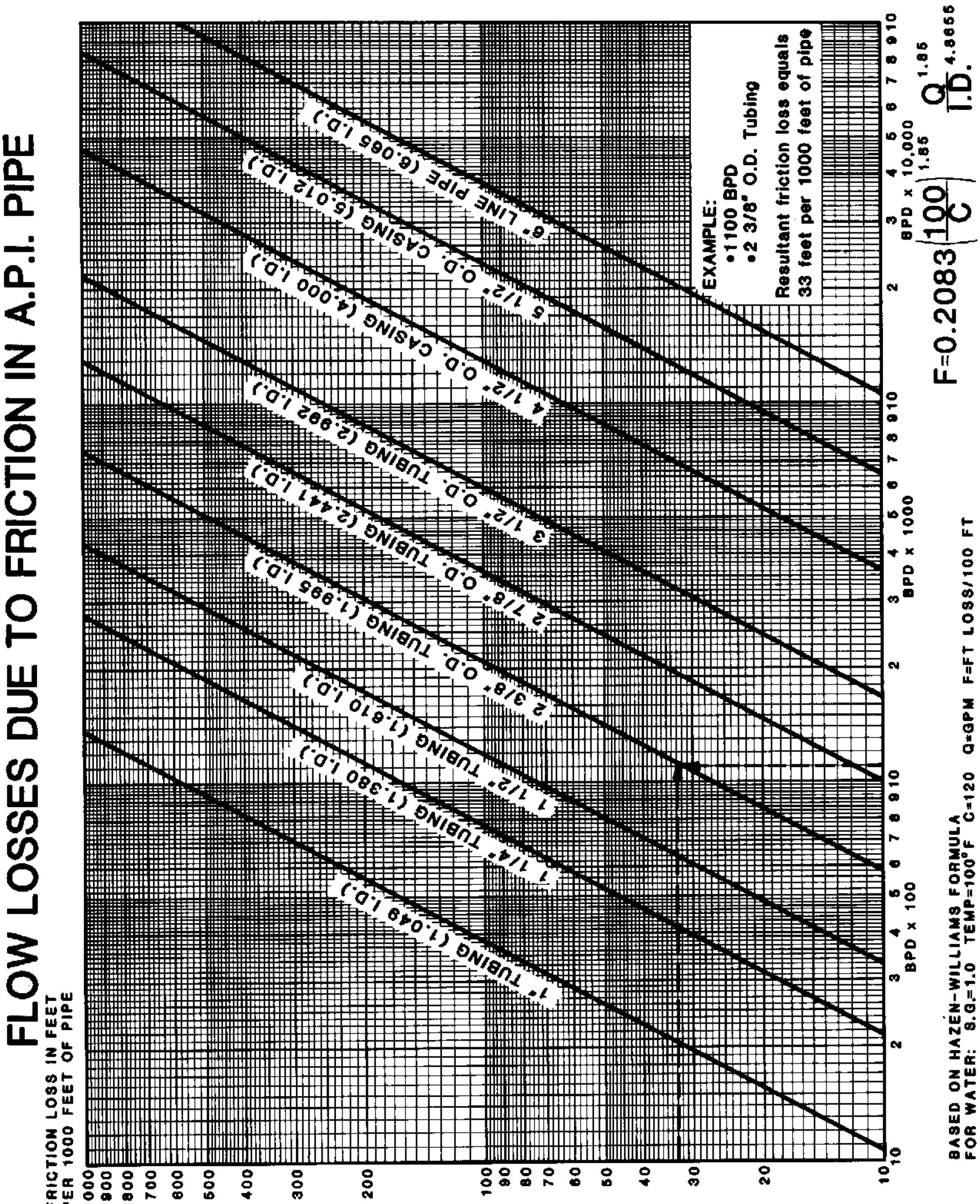



FIG. 2
FLOW LOSSES DUE TO FRICTION IN API PIPE

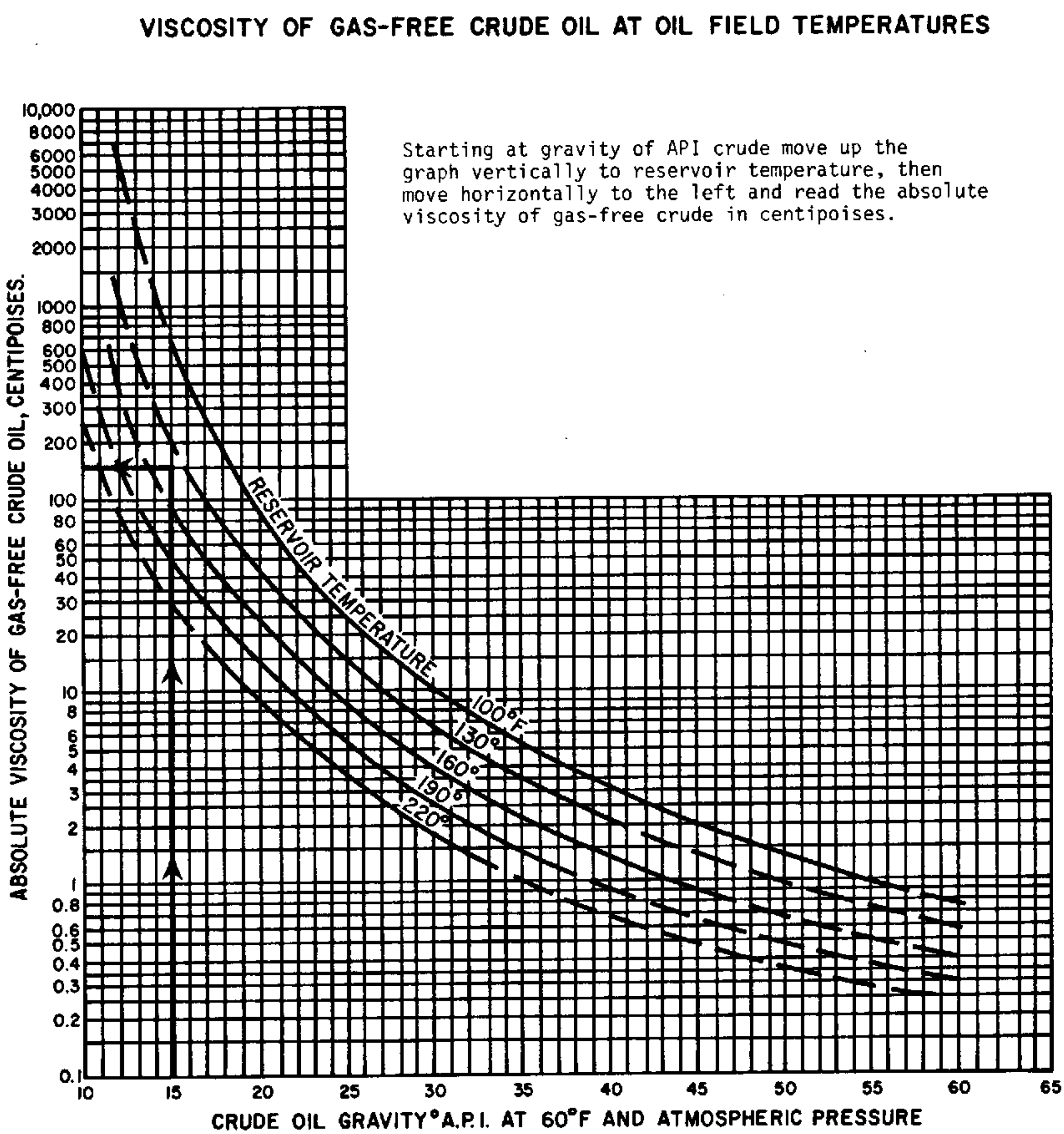



**FIG. 3**
**VISCOSITY OF GAS-FREE CRUDE OIL AT OIL FIELD TEMPERATURES**

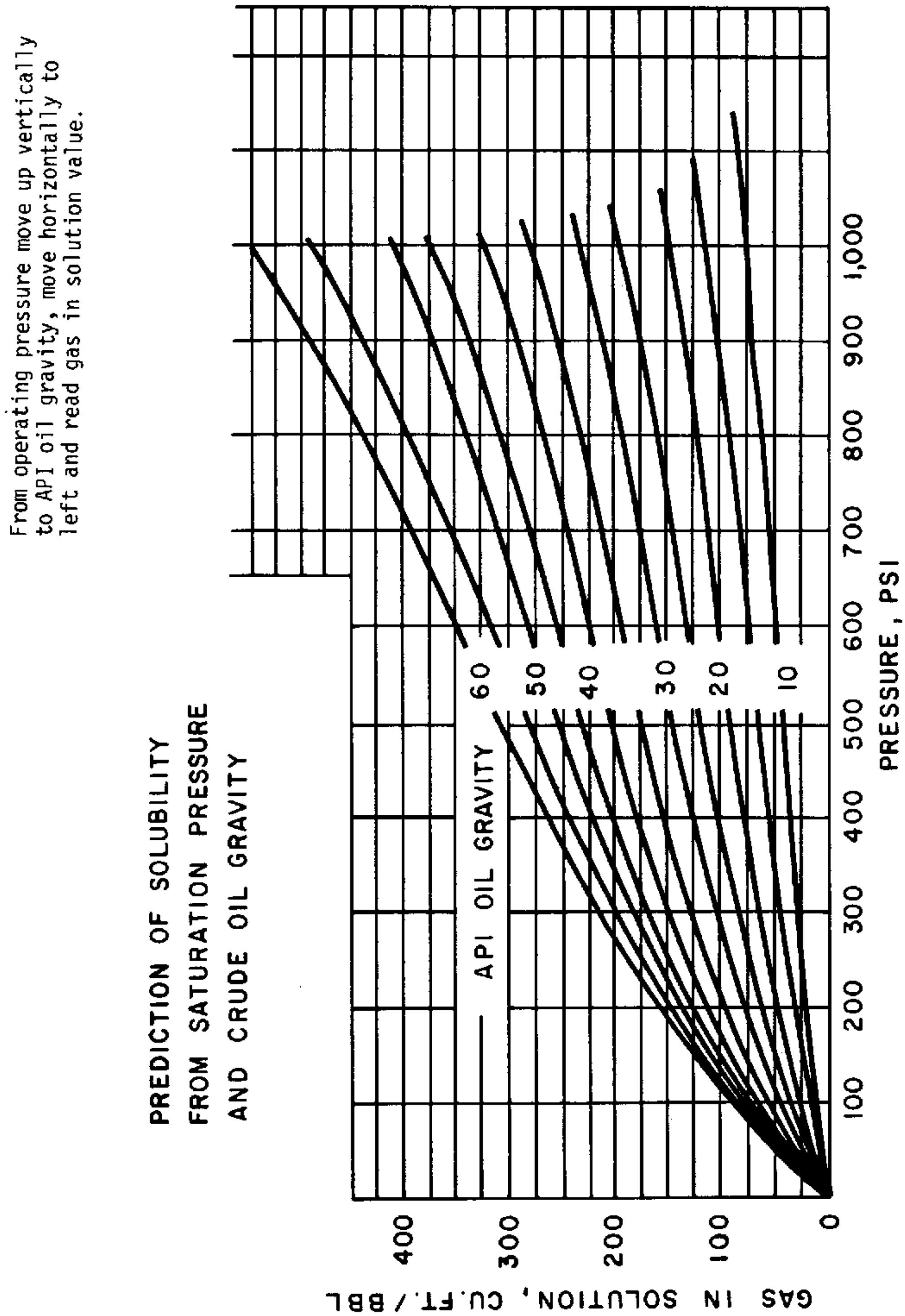

From operating pressure move up vertically
to API oil gravity, move horizontally to
left and read gas in solution value.
PREDICTION OF SOLUBILITY
FROM SATURATION PRESSURE
AND CRUDE OIL GRAVITY
API OIL GRAVITY
60
50
40
30
20
10
100
200
300
400
500
600
700
800
900
1,000
PRESSURE, PSI
0
100
200
300
400
GAS IN SOLUTION, CU.FT./BBL

FIG. 4

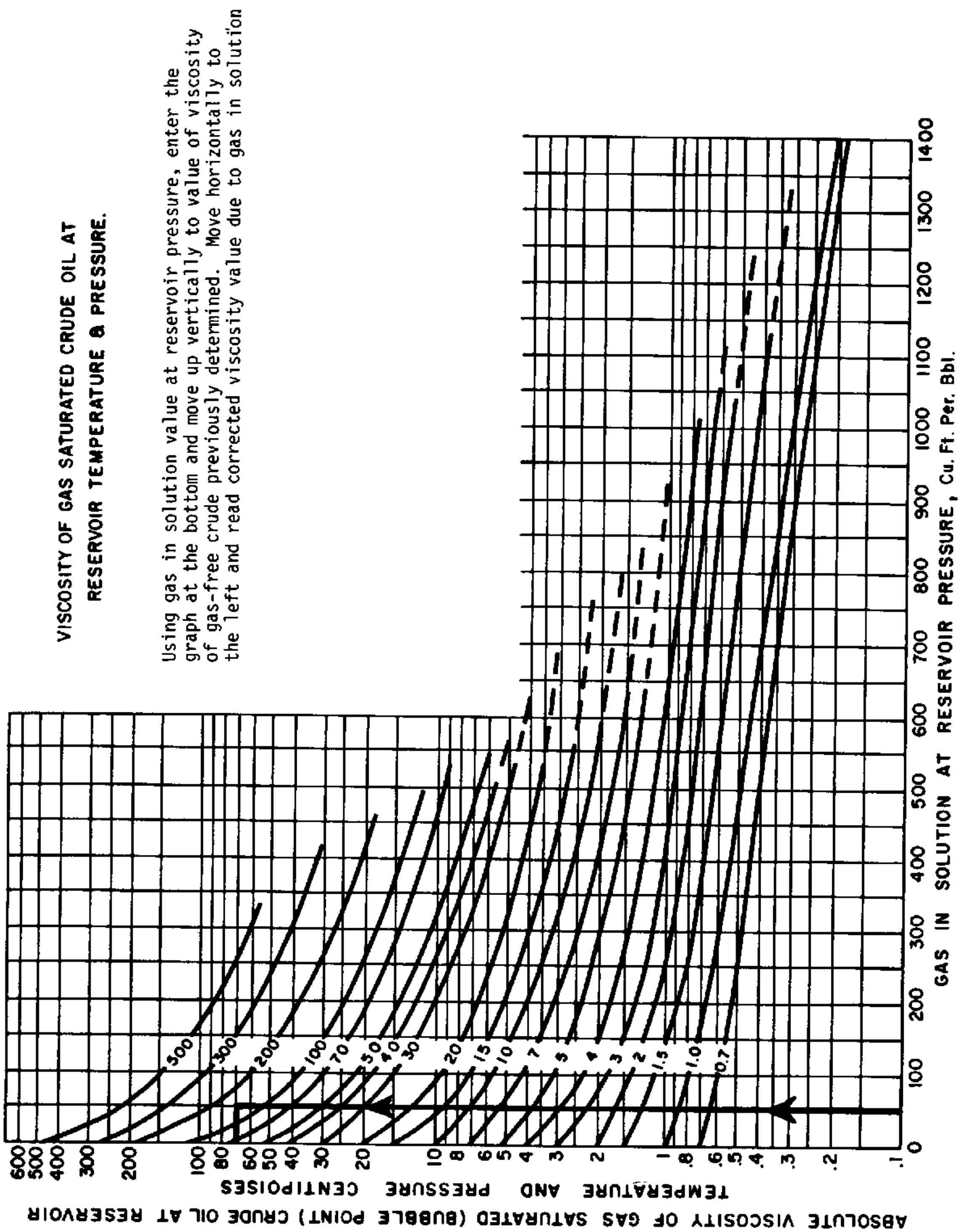
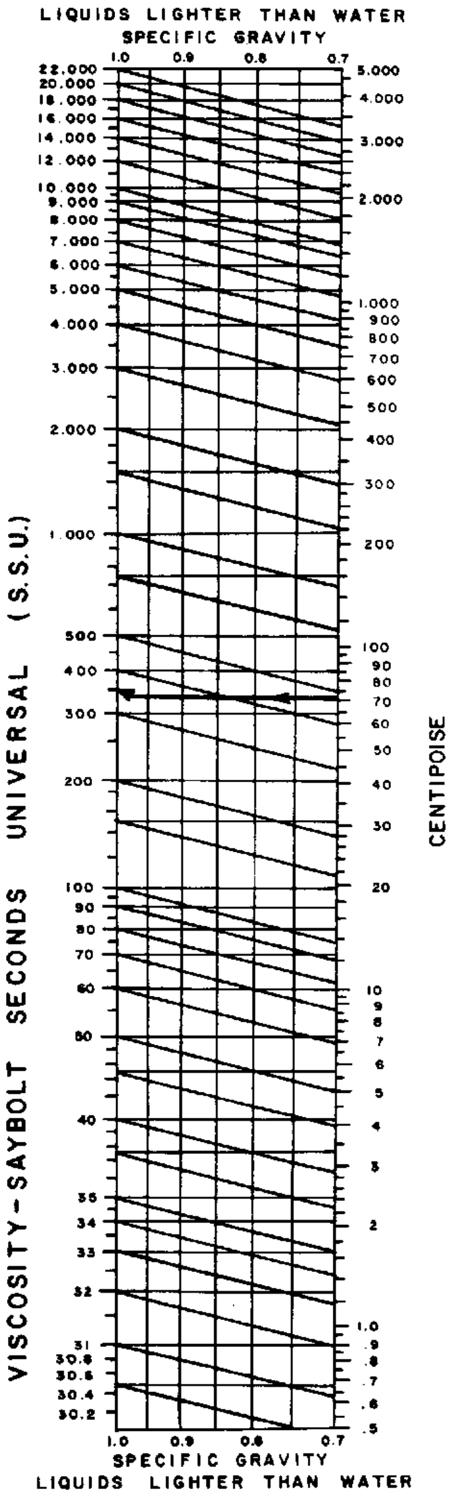


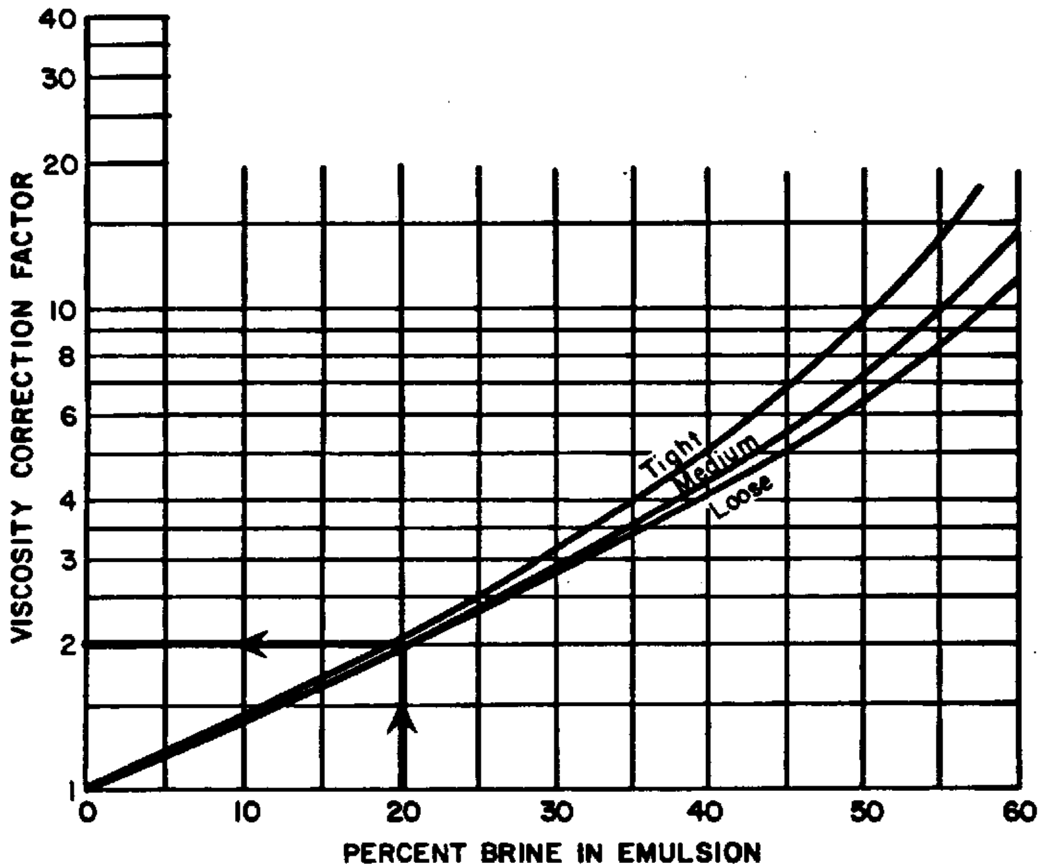

FIG. 5
VISCOSITY OF GAS SATURATED CRUDE OIL AT
RESERVOIR TEMPERATURE & PRESSURE




Using gas in solution viscosity value in centipoise, enter the graph at right and move horizontally to composite specific gravity value. From this point, move parallel to the diagonal line and read viscosity in SSU on the left scale.

FIG. 6

Using percent water cut, go up vertically on graph to type of emulsion, then horizontally to left. Read viscosity correction factor.




Caution: When approaching upper limits of curve care must be taken because individual well characteristics may differ significantly from these curves.

FIG. 7
EFFECT OF EMULSION ON OIL VISCOSITY

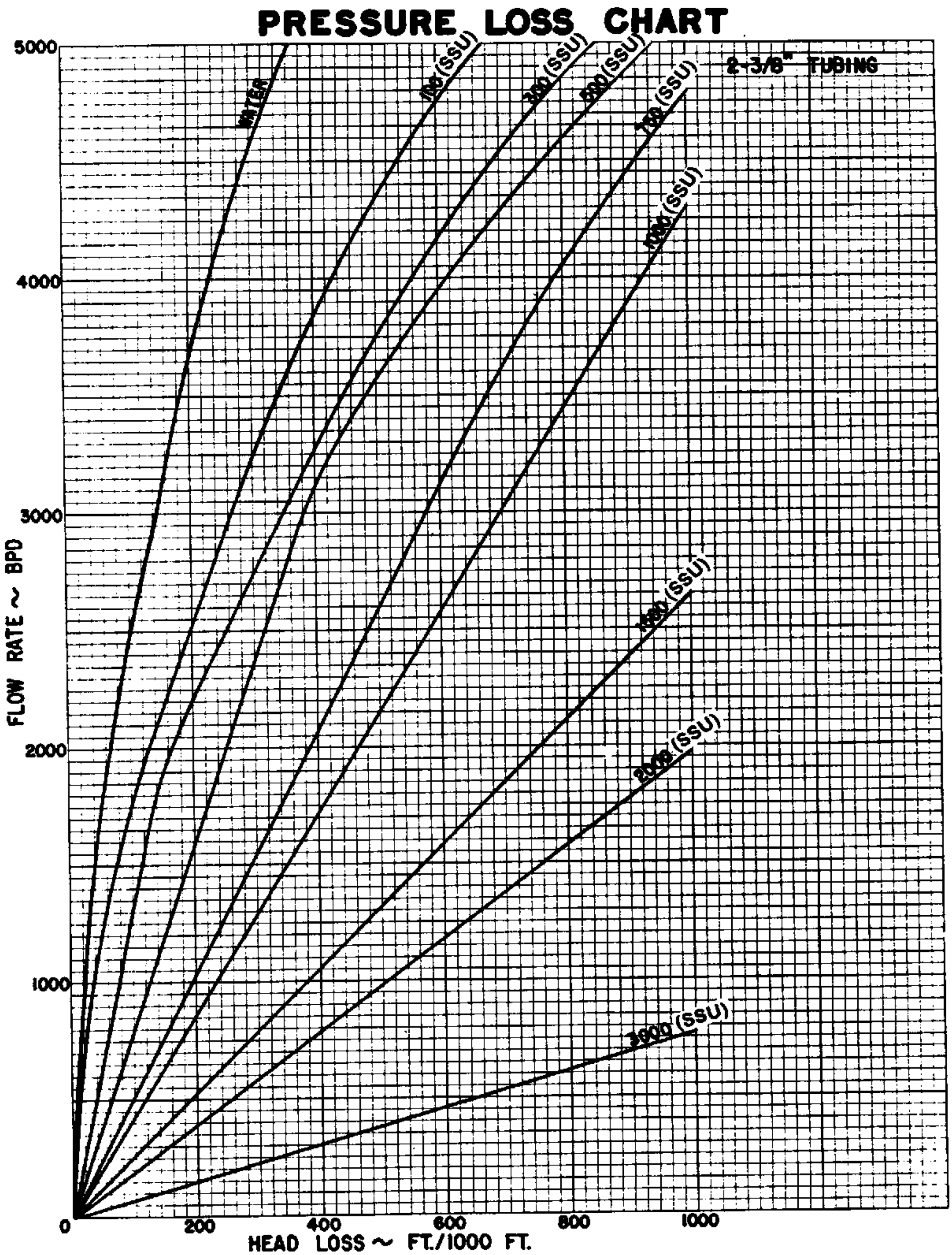

PRESSURE LOSS CHART
2-3/8" TUBING
WATER
100 (SSU)
300 (SSU)
500 (SSU)
750 (SSU)
1000 (SSU)
1500 (SSU)
2000 (SSU)
3000 (SSU)
FLOW RATE ~ BPD
5000
4000
3000
2000
1000
0
200
400
600
800
1000
HEAD LOSS ~ FT./1000 FT.

FIG. 8

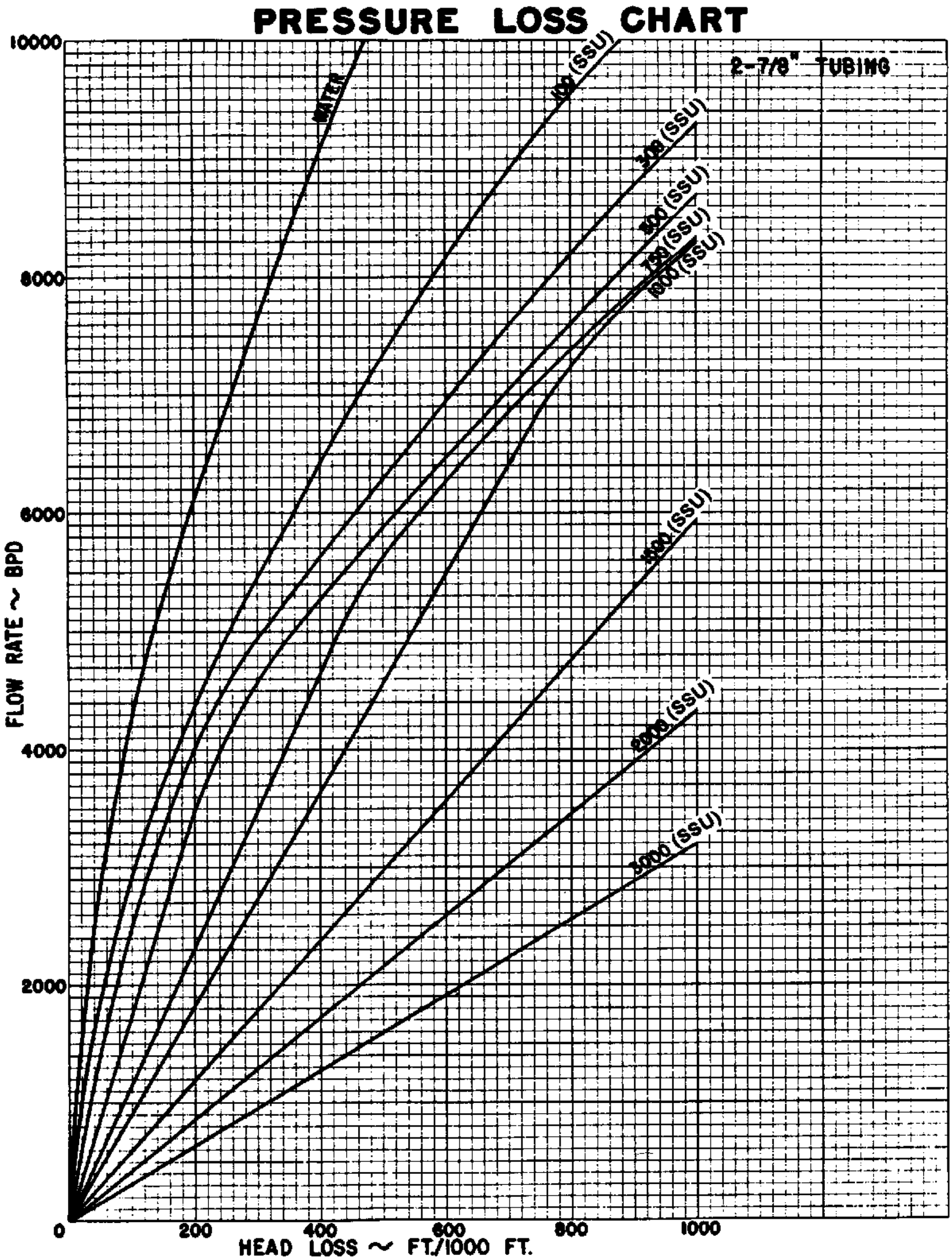

PRESSURE LOSS CHART
2-7/8" TUBING
WATER
100 (SSU)
300 (SSU)
500 (SSU)
750 (SSU)
1000 (SSU)
1500 (SSU)
2000 (SSU)
3000 (SSU)
10000
8000
6000
4000
2000
0
200
400
600
800
1000
FLOW RATE ~ BPD
HEAD LOSS ~ FT./1000 FT.

FIG. 9

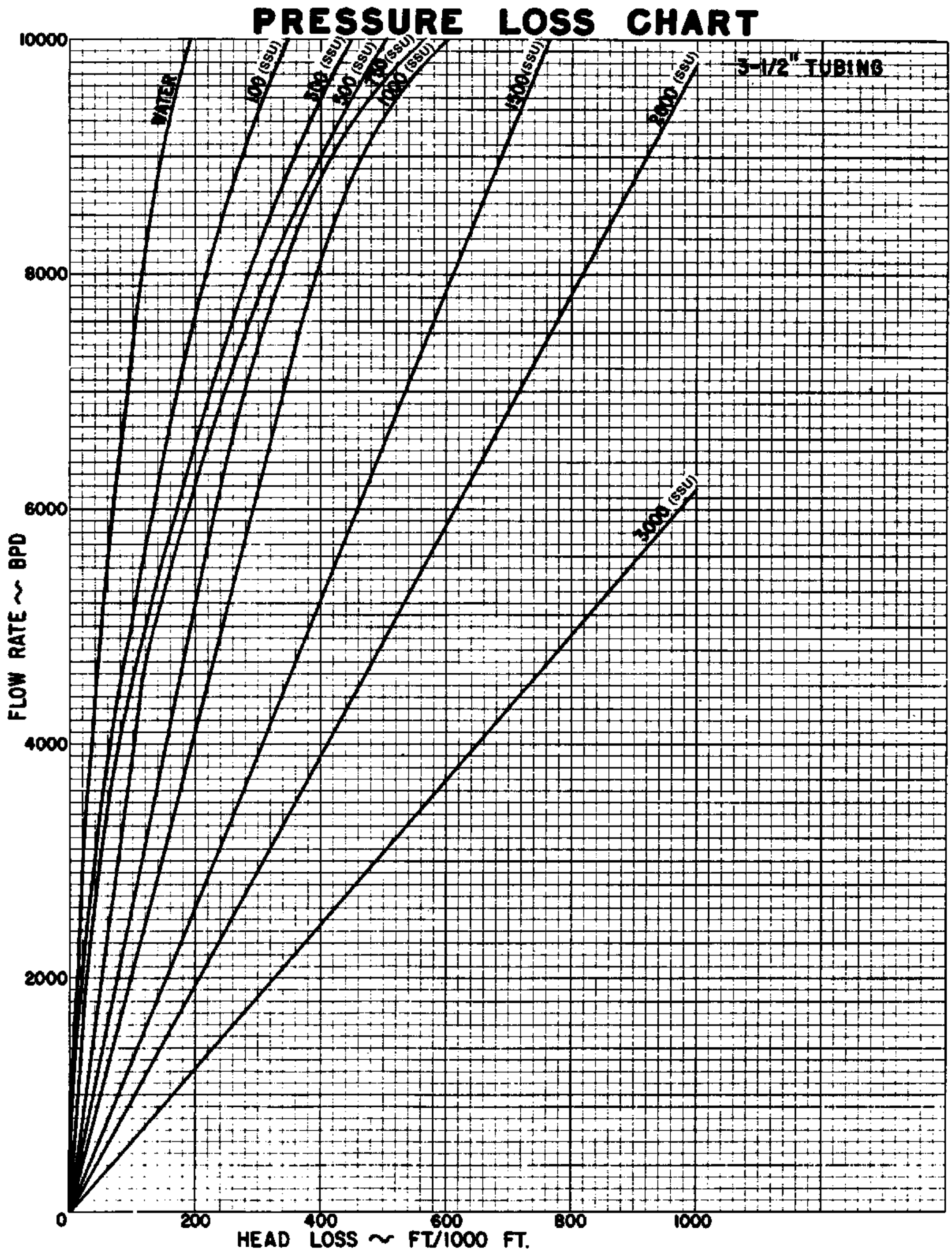

PRESSURE LOSS CHART
3-1/2" TUBING
WATER
100 (SSU)
200 (SSU)
300 (SSU)
500 (SSU)
1000 (SSU)
1500 (SSU)
2000 (SSU)
3000 (SSU)
FLOW RATE ~ BPD
10000
8000
6000
4000
2000
0
200
400
600
800
1000
HEAD LOSS ~ FT/1000 FT.

FIG. 10

FIG. 11
CONVERSION CHART
APPROXIMATE CHANGES DUE TO VISCOSITY
(60% MAXIMUM EFFICIENCY PUMPS)

| VISCOSITY AT PUMPING TEMPERATURES (SSU) | CAPACITY FACTOR | HEAD FACTOR | HORSEPOWER FACTOR |
|---|---|---|---|
| 50 | 1.00 | 0.995 | 1.04 |
| 80 | 0.985 | 0.985 | 1.08 |
| 100 | 0.980 | 0.980 | 1.11 |
| 150 | 0.960 | 0.960 | 1.16 |
| 200 | 0.940 | 0.940 | 1.19 |
| 300 | 0.910 | 0.910 | 1.24 |
| 400 | 0.880 | 0.890 | 1.27 |
| 500 | 0.850 | 0.860 | 1.28 |
| 600 | 0.830 | 0.845 | 1.30 |
| 700 | 0.805 | 0.825 | 1.30 |
| 800 | 0.790 | 0.810 | 1.31 |
| 900 | 0.770 | 0.800 | 1.32 |
| 1000 | 0.775 | 0.780 | 1.33 |
| 1500 | 0.690 | 0.725 | 1.36 |
| 2000 | 0.630 | 0.675 | 1.31 |

# VOLTAGE DROP IN CABLE

Conductor Voltage Drop

| Temp. °F (°C) | Multiplying Factor |
|---|---|
| 100 (38) | 1.070 |
| 110 (43) | 1.092 |
| 120 (49) | 1.114 |
| 130 (54) | 1.136 |
| 140 (60) | 1.157 |
| 150 (66) | 1.179 |
| 160 (71) | 1.201 |
| 170 (77) | 1.223 |
| 180 (82) | 1.245 |
| 190 (88) | 1.267 |
| 200 (93) | 1.288 |
| 210 (99) | 1.310 |
| 220 (104) | 1.332 |
| 230 (110) | 1.354 |
| 240 (116) | 1.376 |
| 250 (121) | 1.398 |
| 260 (127) | 1.420 |
| 270 (132) | 1.441 |
| 280 (138) | 1.463 |
| 290 (143) | 1.485 |
| 300 (159) | 1.507 |

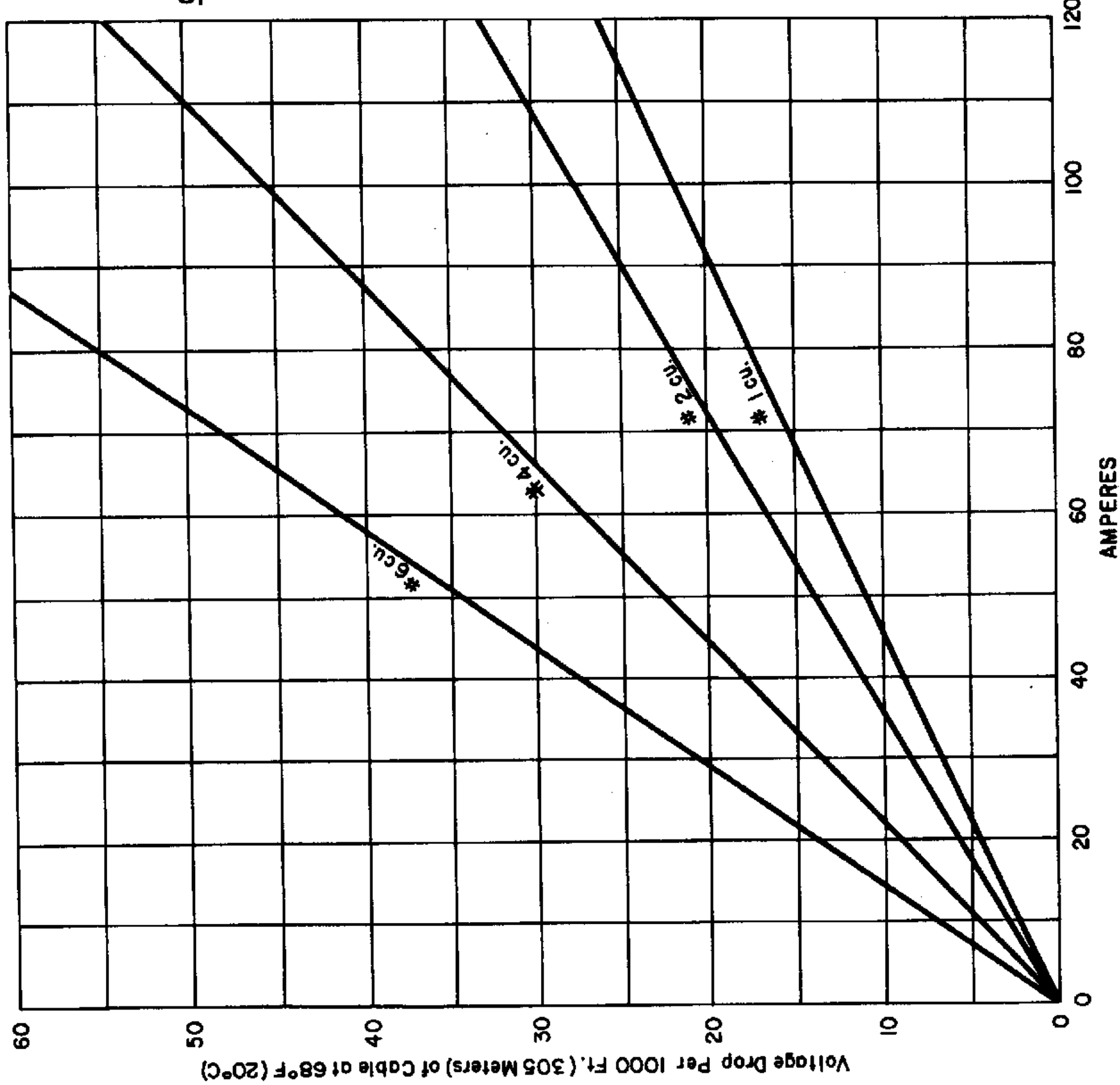



FIG. 12
VOLTAGE DROP IN CABLE

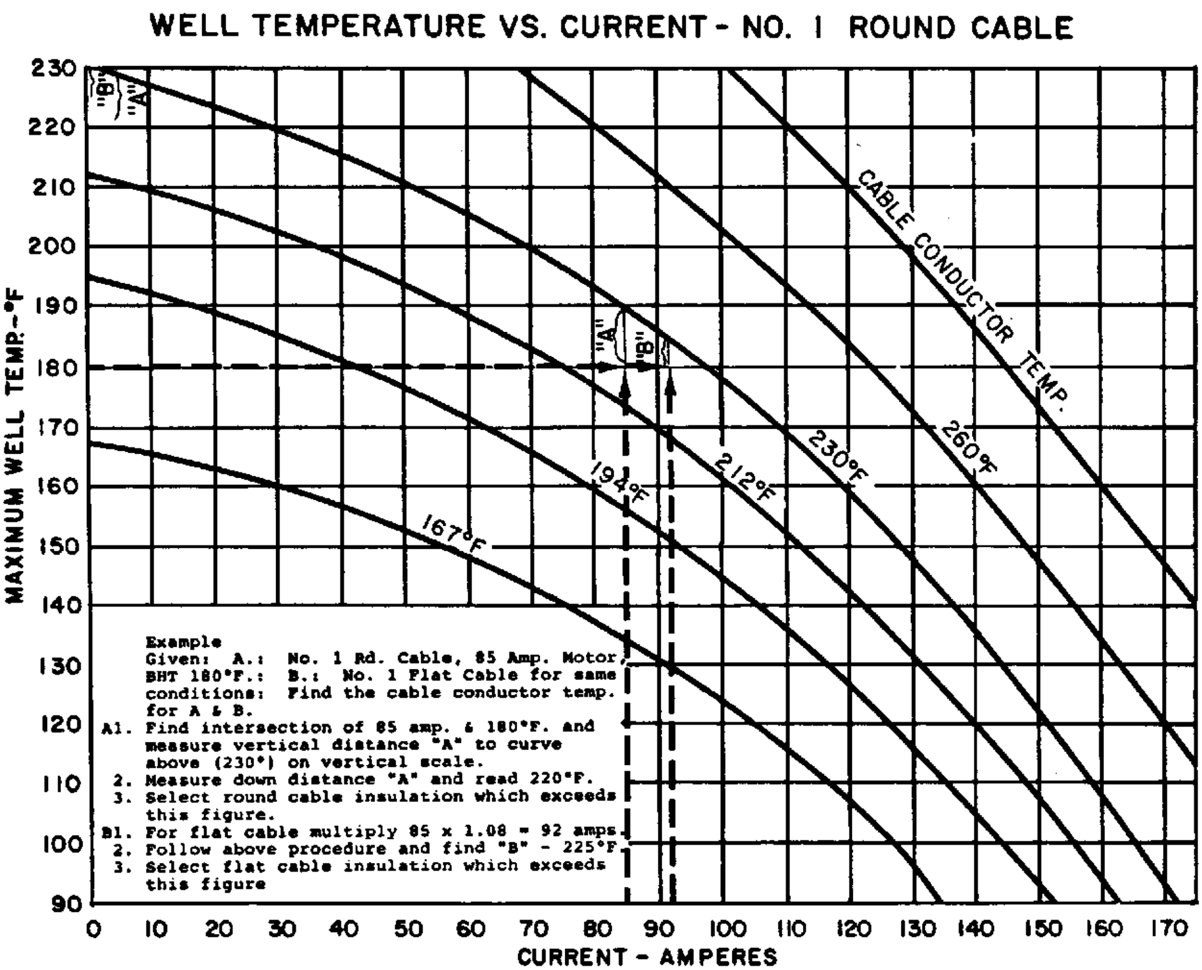



**FIG. 13**
**WELL TEMPERATURE VS. CURRENT**

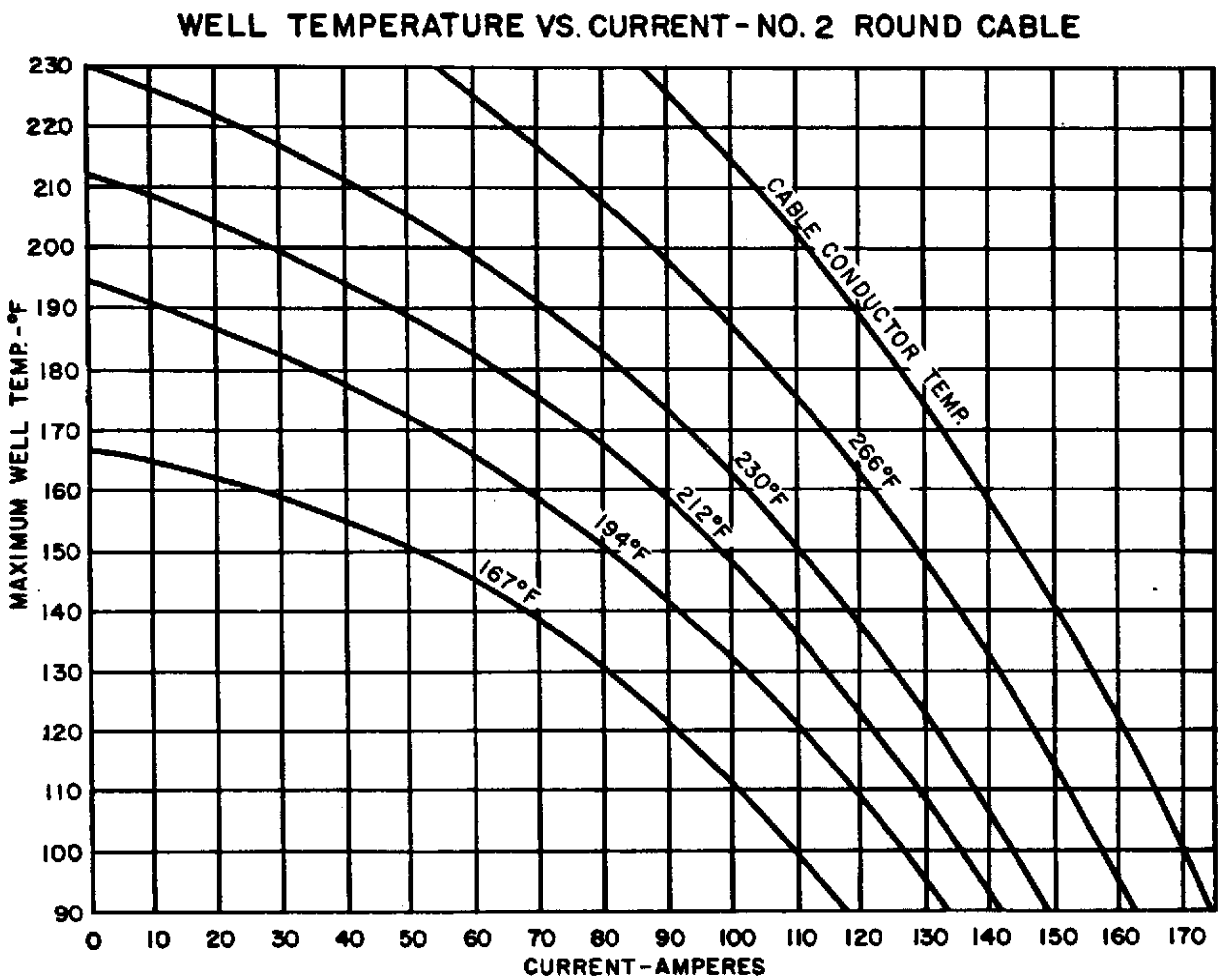



FIG. 14
WELL TEMPERATURE VS. CURRENT
NO. 2 ROUND CABLE

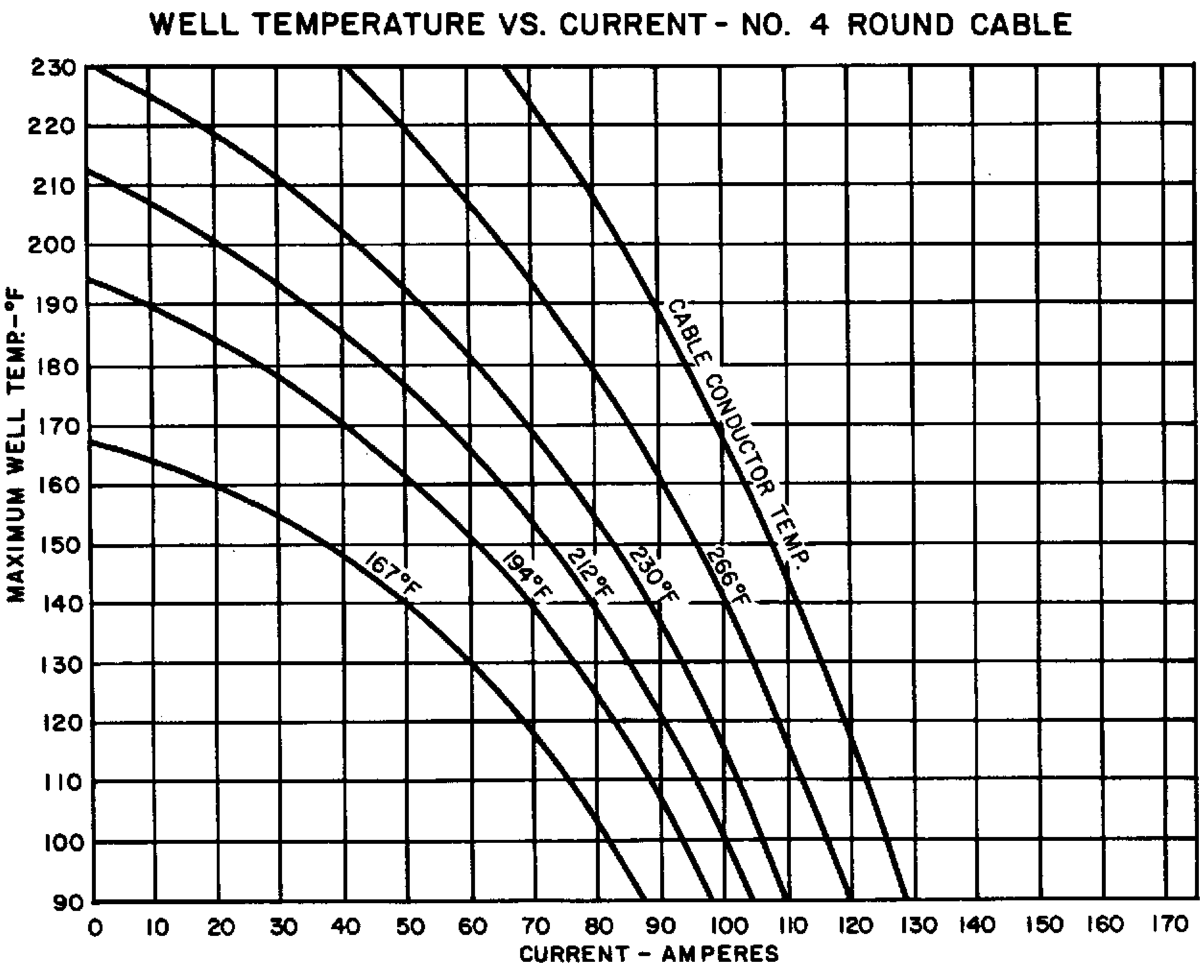



**FIG. 15**
**WELL TEMPERATURE VS. CURRENT**
**NO. 4 ROUND CABLE**

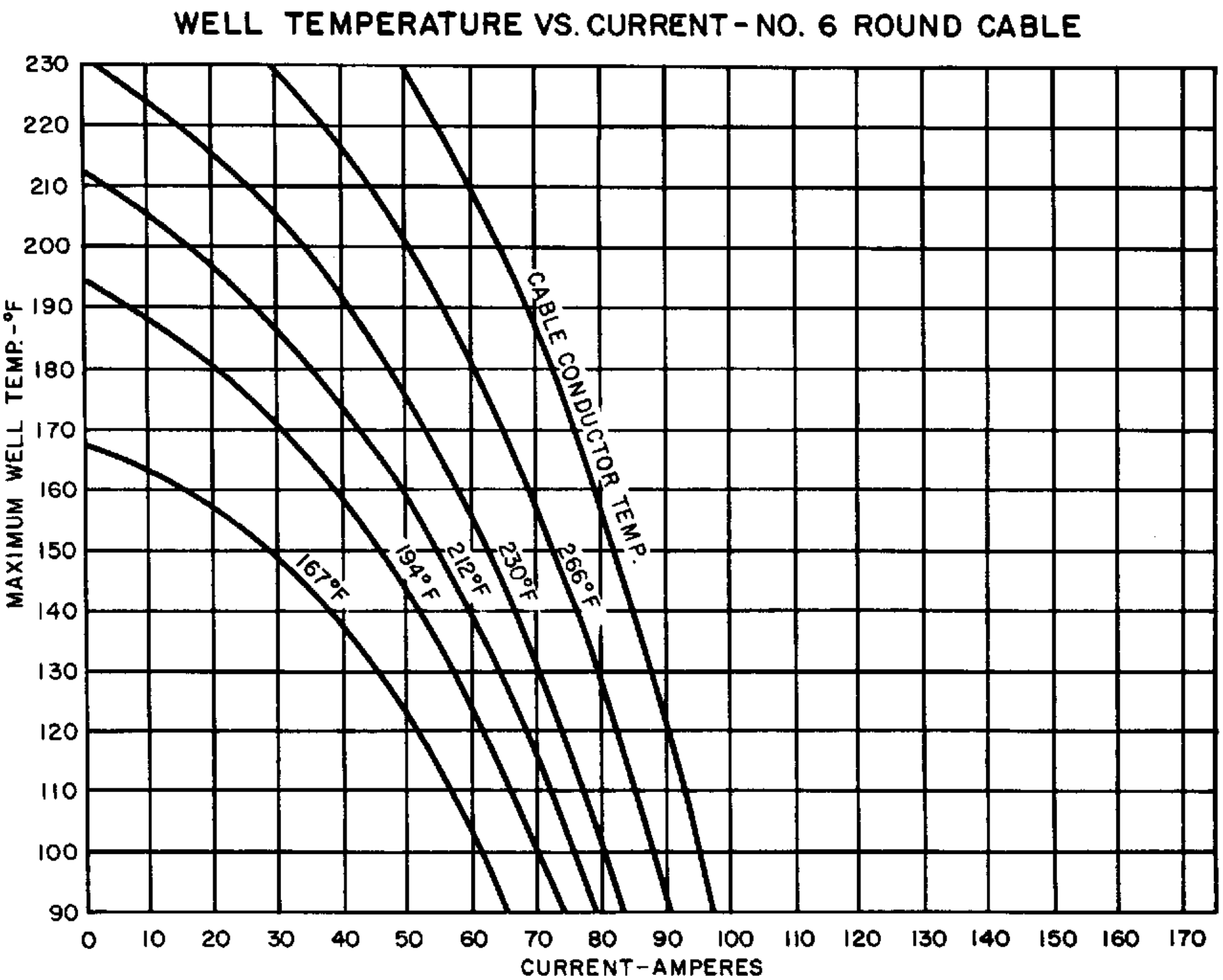
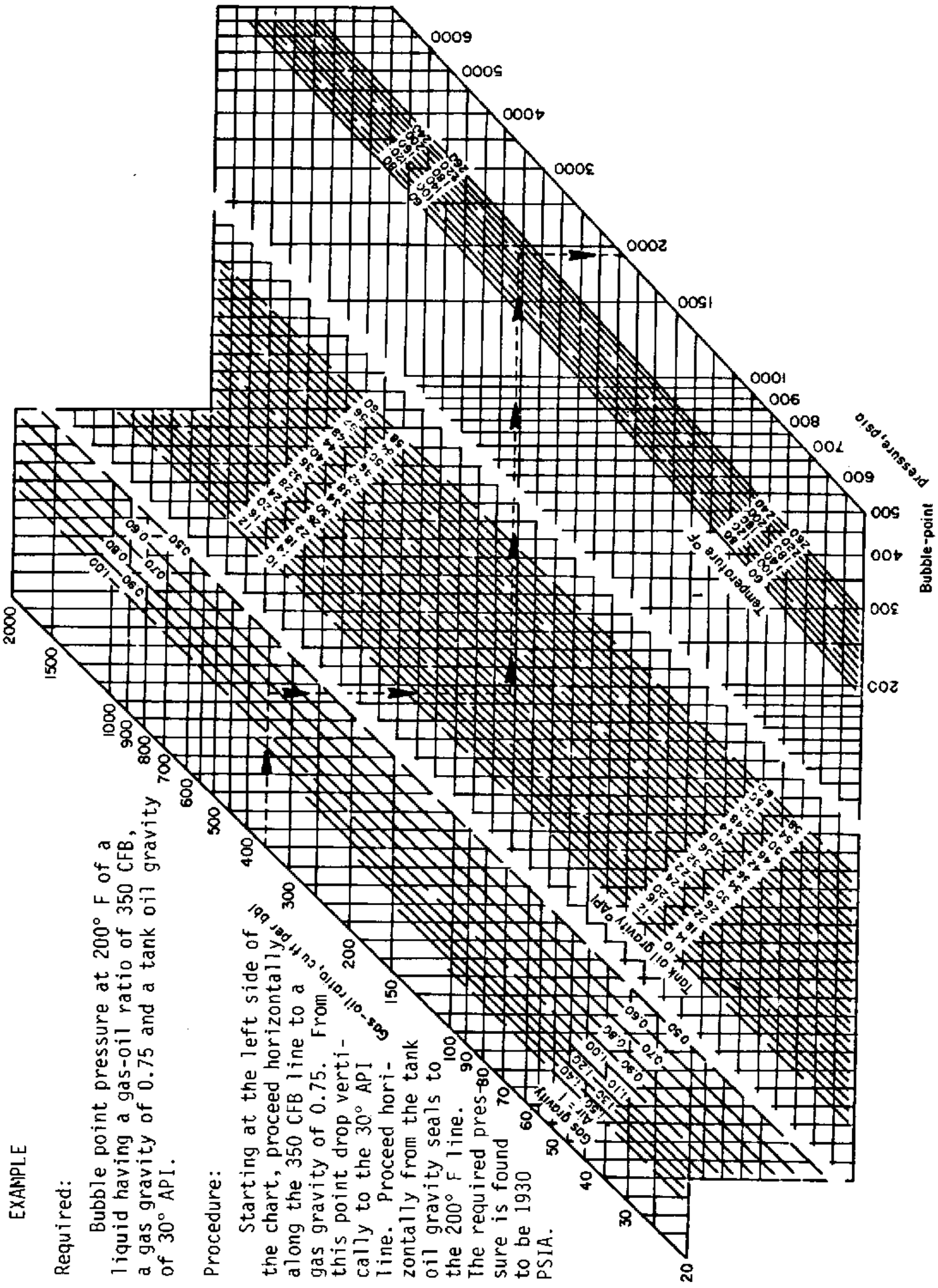



**FIG. 16**
**WELL TEMPERATURE VS. CURRENT**
**NO. 6 ROUND CABLE**

PROPERTIES OF NATURAL HYDROCARBON MIXTURES OF GAS AND LIQUID BUBBLE POINT PRESSURE




EXAMPLE

Required:

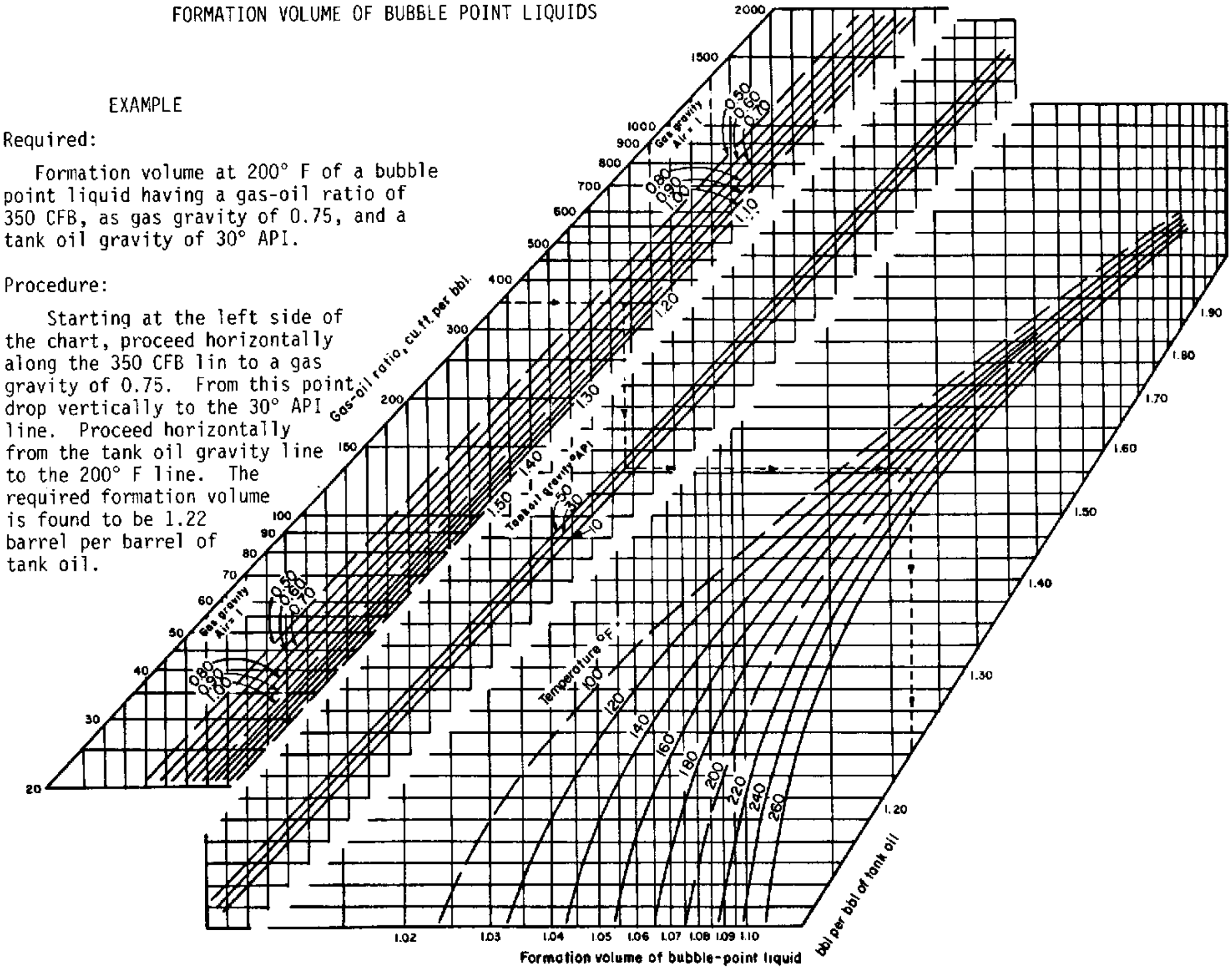
Bubble point pressure at 200° F of a liquid having a gas-oil ratio of 350 CFB, a gas gravity of 0.75 and a tank oil gravity of 30° API.

Procedure:

Starting at the left side of the chart, proceed horizontally along the 350 CFB line to a gas gravity of 0.75. From this point drop vertically to the 30° API line. Proceed horizontally from the tank oil gravity seals to the 200° F line. The required pressure is found to be 1930 PSIA.

**FIG. 17**
**CHART FOR CALCULATING BUBBLE-POINT PRESSURE OR SOLUBILITY**

FORMATION VOLUME OF BUBBLE POINT LIQUIDS




EXAMPLE

Required:

Formation volume at 200° F of a bubble point liquid having a gas-oil ratio of 350 CFB, as gas gravity of 0.75, and a tank oil gravity of 30° API.

Procedure:

Starting at the left side of the chart, proceed horizontally along the 350 CFB lin to a gas gravity of 0.75. From this point drop vertically to the 30° API line. Proceed horizontally from the tank oil gravity line to the 200° F line. The required formation volume is found to be 1.22 barrel per barrel of tank oil.

**FIG. 18**
**CHART FOR CALCULATING FORMATION VOLUME OF BUBBLE-POINT LIQUIDS**

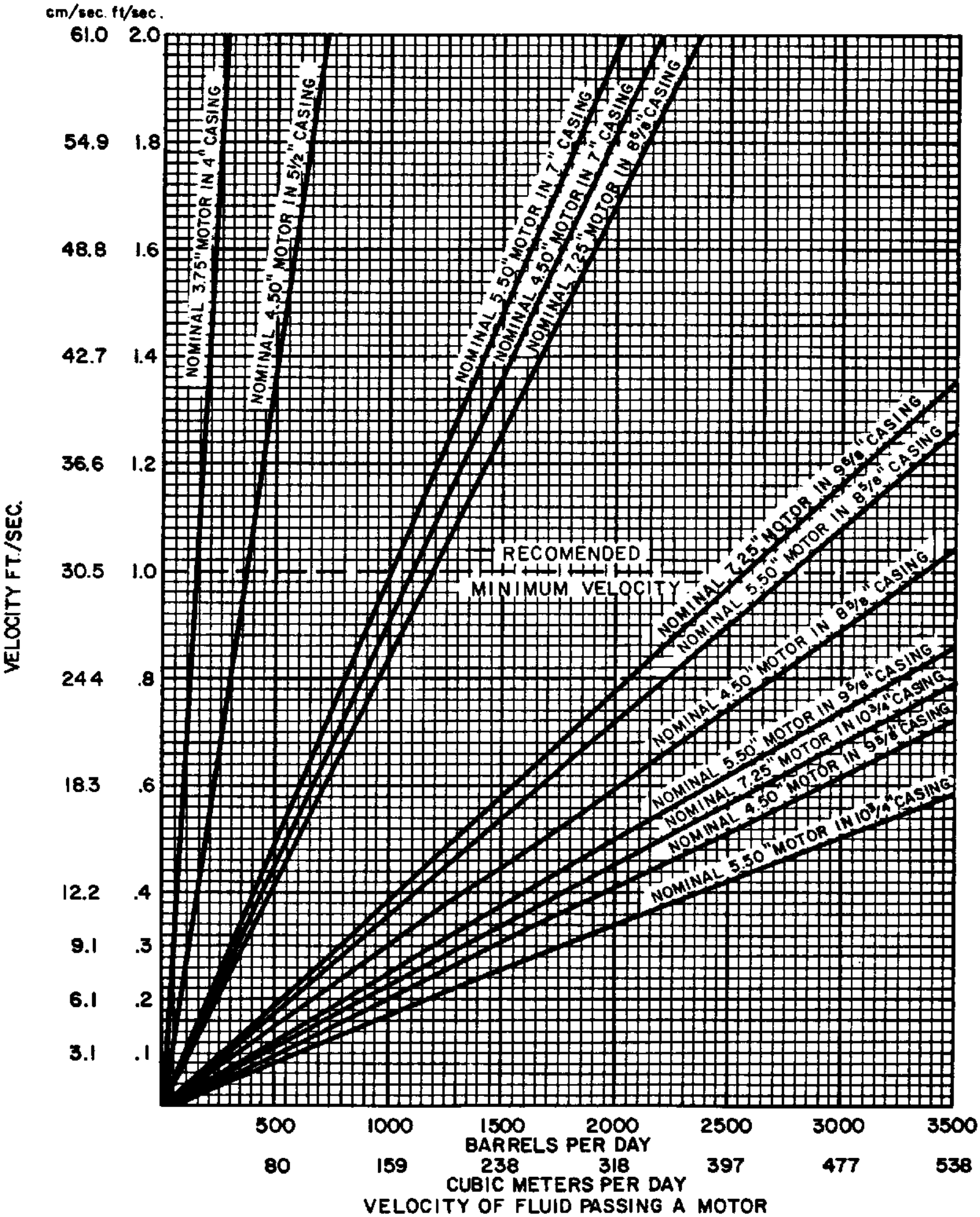



**FIG. 19**
**VELOCITY OF FLUID PASSING A MOTOR**

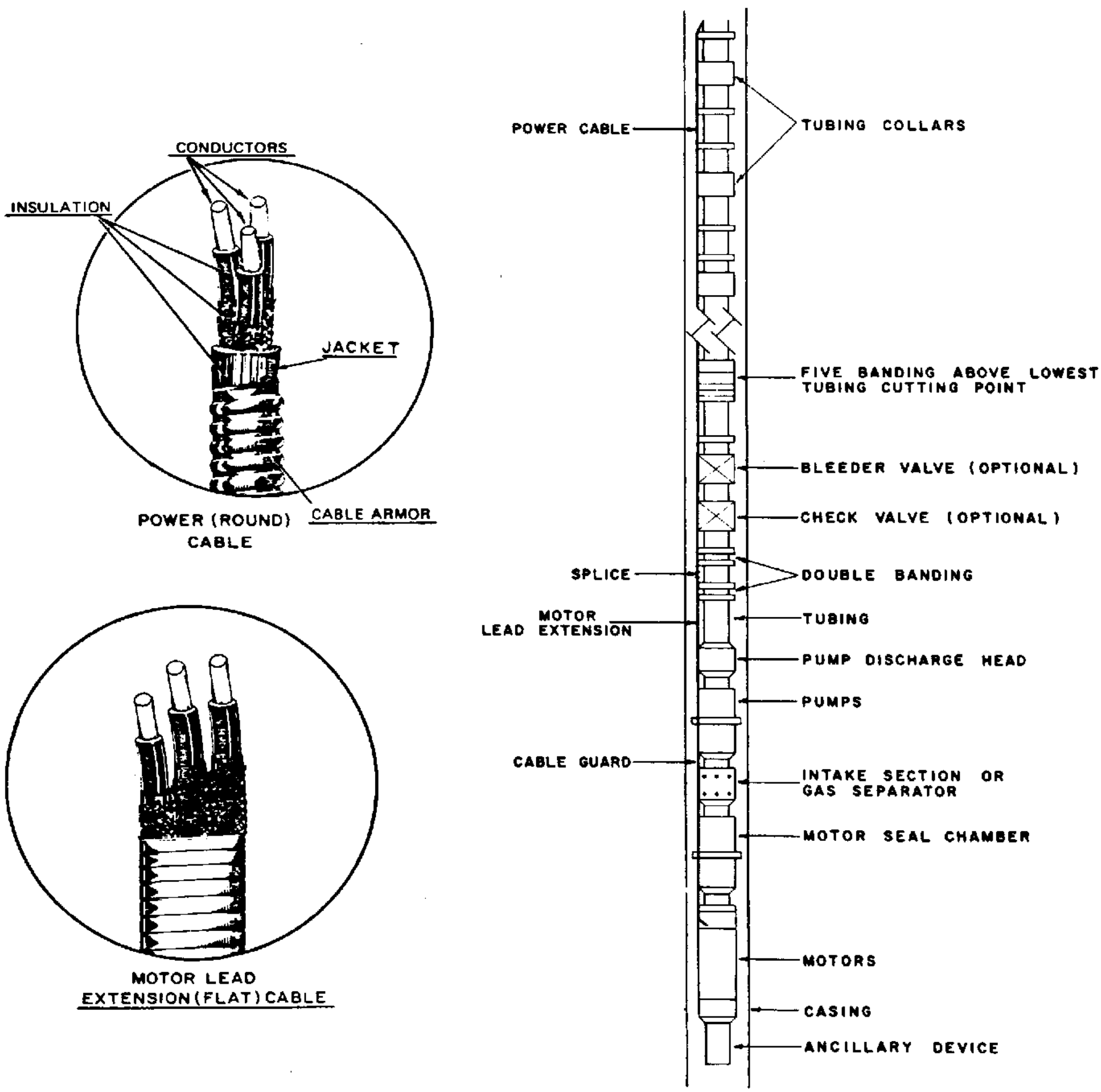



**FIG. 20**
**SUBSURFACE EQUIPMENT**

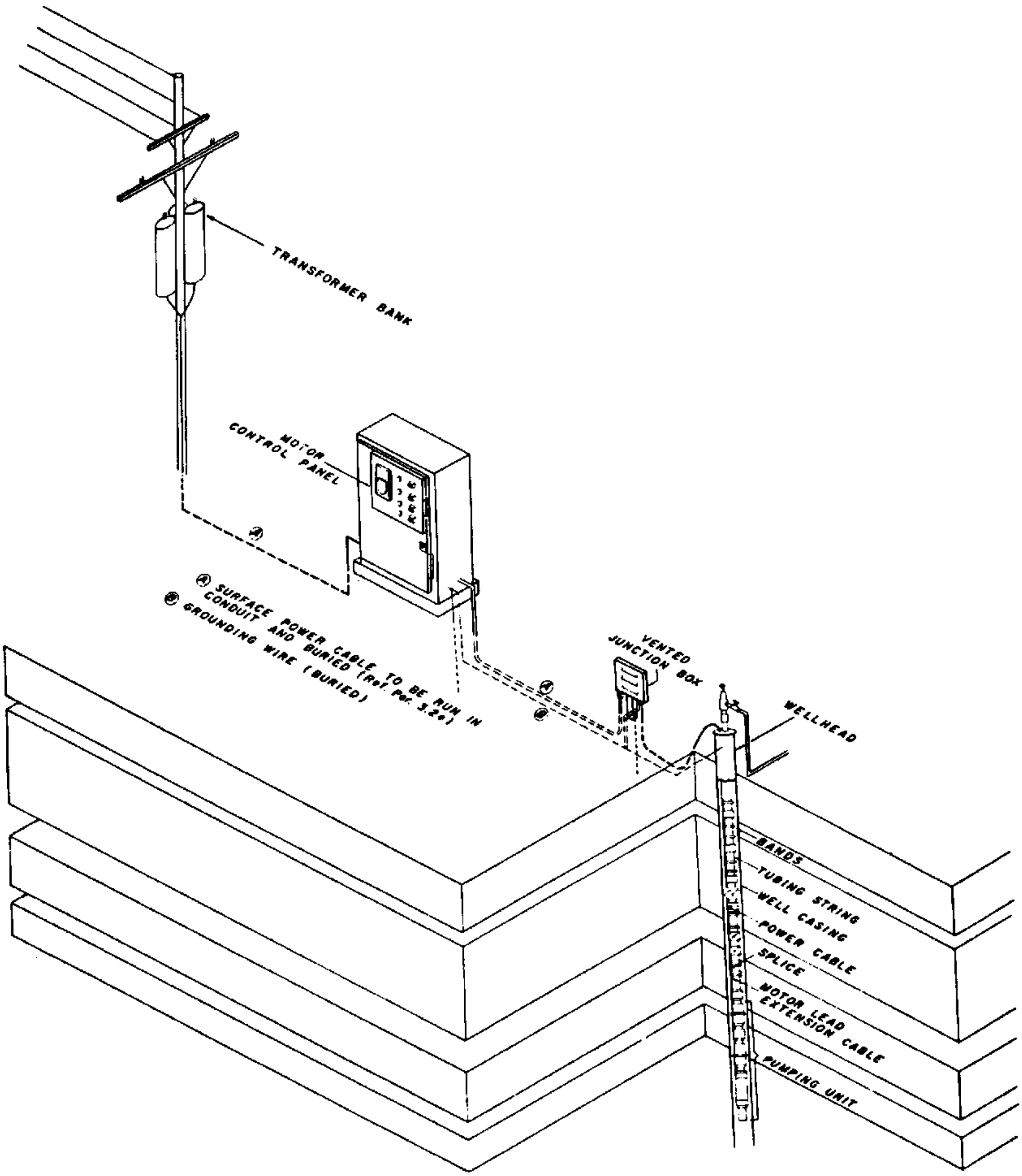



**FIG. 21**
**SURFACE EQUIPMENT**

## WELL DATA SHEET

### A. WELL DATA

1. Well No. & Field Name — Date
2. Well Location (County, State, Other)
3. Installation — New ( ) or Redesign ( )
4. Producing Formations
5. Formation Type (Sandstone, Limestone, Other)
6. *API Casing — In. O.D.: — #/Ft. — Ft. TO — Ft.
7. *Liner — In. O.D.: — #/Ft. — Ft. TO — Ft.
8. *Other Limiting Dimensions — In. I.D. — Ft. TO — Ft.
9. *Open Hole — Ft. TO — Ft.
10. *Total Depth — Ft. Plugged Back Depth — Ft.
11. *Perforated Intervals — Ft. TO — Ft.
    Ft. TO — Ft.
12. *Wellhead Type & Size
13. *API Tubing — In. O.D. — Threads — Grade

### B. RESERVOIR DATA (FROM TEST & PRODUCTION DATA)

1. *Present Production — BOPD — BWPD — BFPD — Pumping ( ) — Flowing ( )
2. Bottom Hole Static Pressure — PSIG AT: — Ft.
3. Bottom Hole Producing Pressure — PSIG AT: — BFPD
   PSIG AT: — BFPD
4. GOR — S.C.F./S.T.B.
5. *Water Cut — %
6. Oil API Gravity — °API — °
7. Water Specific Gravity
8. Gas Specific Gravity
9. Bottom Hole Temperature — °F
10. Oil Viscosity (1) — CP.OR — SSU At — °F
    (2) — CP.OR — SSU At — °F
11. PVT Data — Solution GOR — FVF — PSIG
    Solution GOR — FVF — PSIG
    Solution GOR — FVF — PSIG
    Solution GOR — FVF — PSIG
12. Bubble Point Pressure — PSIG

### C. SIZING SPECIFICATIONS

1. *Desired Production — BFPD — BOPD — BWPD
2. Desired Pump (Intake) Vertical Setting Depth — Ft.
3. Desired Pump (Intake) Pressure — PSIG
4. Required Wellhead Pressure — PSIG
5. Gas Through Pump — % (Of Total Gas)
6. Primary Voltage Available — Volts — Hertz
7. Casing Pressure — PSIG
8. Special Problems: Sand ( ) Scale ( ) Corrosion ( ) Paraffin ( ) $H_2S$ ( ) $CO_2$ ( )

REMARKS: ____________________

BY: ____________________ DATE: ____________________

*Indicates Data That Must Be Provided

**FIG. 22**
**ELECTRIC SUBMERSIBLE PUMP**
**WELL DATA SHEET**

WELL DATA SHEET

A. WELL DATA

1. Well No. & Field Name EXAMPLE PROBLEM NO. 1 Date 10-25-82
2. Well Location (County, State, Other) OIL & WATER — NO GAS
3. Installation New (X) or Redesign ( )
4. Producing Formations
5. Formation Type (Sandstone, Limestone, Other)
6.*API Casing 5½ In. O.D.: 15.5 & 17 #/Ft. 10,000 Ft. TO Ft.
7.*Liner NONE In. O.D.: #/Ft. Ft. TO Ft.
8.*Other Limiting Dimensions NONE In. I.D. Ft. TO Ft.
9.*Open Hole NONE Ft. TO Ft.
10.*Total Depth 10,000 Ft. Plugged Back Depth 9960 Ft.
11.*Perforated Intervals 9800 Ft. TO 9840 Ft.
9880 Ft. TO 9900 Ft.
12.*Wellhead Type & Size HHS 2⅜
13.*API Tubing 2⅜ In. O.D. 8EU Threads J-55 Grade

B. RESERVOIR DATA (FROM TEST & PRODUCTION DATA)

1.*Present Production 50 BOPD 200 BWPD 250 BFPD Pumping (X) Flowing ( )
2. Bottom Hole Static Pressure 4000 PSIG AT: 9850 Ft.
3. Bottom Hole Producing Pressure 3300 PSIG AT: 250 BFPD
PSIG AT: BFPD
4. GOR NIL S.C.F./S.T.B.
5.*Water Cut 80.0%
6. Oil API Gravity 37.0 °API 0.840 SP.GR.°
7. Water Specific Gravity 1.060
8. Gas Specific Gravity N.A.
9. Bottom Hole Temperature 190°F @ PUMP SETTING DEPTH
10. Oil Viscosity (1) CP.OR 40 SSU At 195 °F
(2) CP.OR SSU At °F
11. PVT Data NONE Solution GOR FVF PSIG
Solution GOR FVF PSIG
Solution GOR FVF PSIG
Solution GOR FVF PSIG
12. Bubble Point Pressure 500 PSIG

C. SIZING SPECIFICATIONS

1.*Desired Production 1100 BFPD 220 BOPD 880 BWPD
2. Desired Pump (Intake) Vertical Setting Depth 9000 Ft.
3. Desired Pump (Intake) Pressure 500 PSIG
4. Required Wellhead Pressure 100 PSIG
5. Gas Through Pump 0% (Of Total Gas)
6. Primary Voltage Available 14,400/24,900 Volts 60 Hertz
7. Casing Pressure 0 PSIG
8. Special Problems: NONE Sand ( ) Scale ( ) Corrosion ( ) Paraffin ( ) $H_2S$ ( ) $CO_2$ ( )

REMARKS:
**Operator desires stainless steel bands, three single phase transformers,**
**and no check valve or drain valve**

BY: **A. B. Jones** DATE: **10-25-82**

*Indicates Data That Must Be Provided

**EXHIBIT 1.1**
**ELECTRIC SUBMERSIBLE PUMP WELL DATA SHEET**
**EXAMPLE PROBLEM NO. 1**

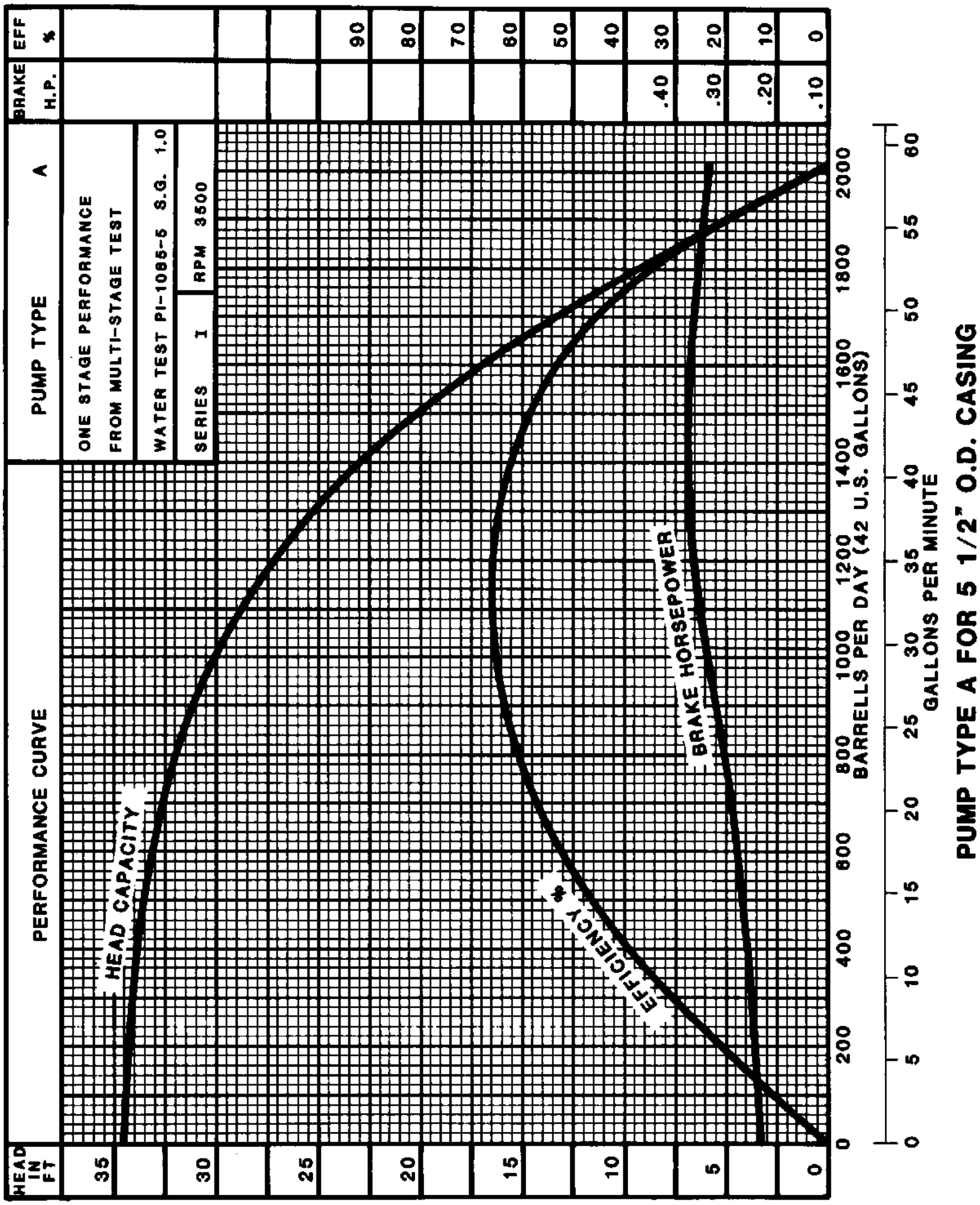



EXHIBIT 1.2
PUMP TYPE A FOR 5½" O.D. CASING
PUMP TYPE A

# SERIES I, PUMP TYPE A
## (FOR 5 1/2" O.D. AND LARGER CASINGS)
# SPECIFICATIONS
## PUMP DISCHARGE 2 3/8" O.D. EUE 8 ROUND THREAD

| HOUSING NO. | SHIPPING LENGTH (FEET) | WEIGHT (POUNDS) | NO. OF STAGES |
|---|---|---|---|
| 2 | 5.2 | 145 | 26 |
| 2 | 5.2 | 155 | 34 |
| 3 | 6.7 | 188 | --- |
| 3 | 6.7 | 198 | 51 |
| 4 | 8.2 | 231 | 59 |
| 4 | 8.2 | 241 | 68 |
| 5 | 9.7 | 274 | --- |
| 5 | 9.7 | 284 | 79 |
| 5 | 9.7 | 294 | 85 |
| 6 | 11.2 | 327 | 101 |
| 7 | 12.7 | 370 | 118 |
| 8 | 14.2 | 413 | 135 |
| 9 | 15.7 | 446 | 152 |
| 10 | 17.2 | 489 | 169 |
| 11 | 18.7 | 532 | 186 |
| 12 | 20.2 | 575 | 203 |
| 13 | 21.7 | 618 | 220 |
| 14 | 23.2 | 661 | 237 |
| 15 | 24.7 | 702 | 254 |
| 16T | 27.7 | 820 | 271 |
| 17T | 29.2 | 863 | 288 |
| 18T | 30.7 | 906 | 305 |
| 19T | 32.2 | 949 | 322 |
| 20T | 33.7 | 992 | 339 |
| 21T | 35.2 | 1035 | 355 |
| 22T | 36.7 | 1078 | 372 |
| 23T | 38.2 | 1121 | 389 |
| 24T | 39.7 | 1164 | 406 |
| 25T | 41.2 | 1207 | 423 |
| 26T | 42.7 | 1250 | 440 |
| 27T | 44.2 | 1297 | 457 |
| 28T | 45.7 | 1340 | 474 |
| 29T | 47.2 | 1383 | 491 |
| 30T | 48.7 | 1426 | 508 |

1. Housing numbers ending with "T" are 2-piece pumps.
2. Above pumps fit I Series seal section.

**EXHIBIT 1.3**
**PUMP TYPE A**

# MOTORS
## (60 CYCLE, 3500 RPM)
## RATING, SPECIFICATIONS

### SERIES I FOR 5 1/2" O.D. AND LARGER CASING

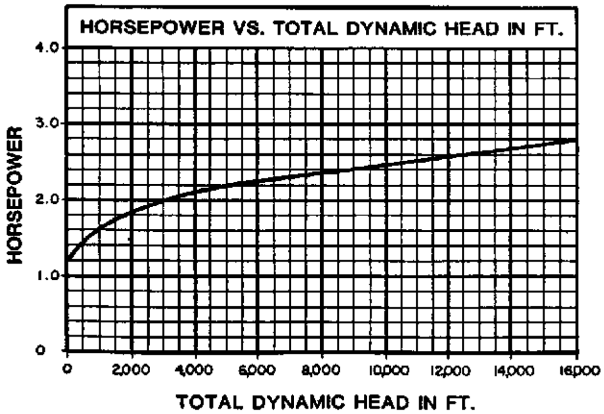
| H.P. | VOLTS | AMPS | LENGTH | WEIGHT, LBS. |
|---|---|---|---|---|
| 15 | 430 | 22 | 5.8' | 263 |
| 22½ | 430 | 33 | 7.5' | 350 |
| | 700 | 21 | | |
| 30 | 430 | 44 | 9.2' | 425 |
| | 720 | 27 | | |
| 37½ | 450 | 53 | 10.9' | 512 |
| | 720 | 33 | | |
| | 890 | 28 | | |
| 45 | 750 | 38 | 12.6' | 595 |
| | 1080 | 27 | | |
| 52½ | 750 | 44 | 14.3' | 687 |
| | 1130 | 30 | | |
| 60 | 720 | 53 | 16.0' | 763 |
| | 1150 | 33 | | |
| 75 | 1250 | 38 | 19.3' | 935 |
| 90 | 1290 | 45 | 22.7' | 1095 |
| | 2150 | 27 | | |
| 105 | 1260 | 53 | 26.1' | 1265 |
| | 2270 | 30 | | |
| 120 | 1150 | 67 | 29.5' | 1430 |
| | 2280 | 34 | | |

### SERIES I MOTORS LISTED BELOW ARE TANDEM (Two Piece) CONSTRUCTION

| H.P. | VOLTS | AMPS | LENGTH | WEIGHT, LBS. |
|---|---|---|---|---|
| 150 | 2130 | 46 | 19.5' & 19.5' | 1875 |
| 180 | 2120 | 55 | 22.9' & 22.9' | 2195 |
| 210 | 2280 | 59 | 26.3' & 26.3' | 2535 |
| 240 | 2250 | 68 | 29.5' & 29.5' | 2860 |

**EXHIBIT 1.4**
**MOTORS**
**(60 Cycle, 3500 RPM)**
**RATING, SPECIFICATIONS**

**MOTOR SEAL CHAMBER HP CURVE**




| MODEL | MINIMUM CASING SIZE (INCHES) | SHIPPING LENGTH (FEET) | WEIGHT (POUNDS) |
|---|---|---|---|
| 1 | 5½ | 4.5' | 110 |
| 2 | 5½ | 5.5' | 130 |
| 3 | 7 | 4.5' | 175 |
| 4 | 7 | 5.6' | 195 |

NOTE: Model 2 is designed for use with Tandem (150 HP or larger) Motors. Model 4 is designed for use with Tandem (360 HP or larger) Motors.

**EXHIBIT 1.5**
**MOTOR SEAL CHAMBER**

| | RATINGS | | | DIMENSIONS & WEIGHTS | | | |
|---|---|---|---|---|---|---|---|
| NEMA SIZE | VOLTS | MAX. AMPS | MAX. H.P. | HEIGHT | WIDTH | DEPTH | WEIGHT (POUNDS) |
| A2 | 440 | 50 | 25 | 48 | 28 | 10½ | 215 |
| A3 | 440 | 100 | 50 | 48 | 28 | 10½ | 290 |
| A4 | 440 | 150 | 100 | 48 | 28 | 10½ | 310 |
| A5 | 440 | 300 | 200 | 48 | 28 | 10½ | 350 |
| B2 | 880 | 50 | 40 | 48 | 28 | 10½ | 290 |
| B3 | 880 | 100 | 75 | 48 | 28 | 10½ | 295 |
| C3 | 1500 | 100 | 150 | 71 | 28 | 20 | 680 |
| C4 | 1500 | 150 | 225 | 71 | 28 | 20 | 710 |
| D3 | 2500 | 200 | 700 | 67 | 31 | 38 | 930 |
| D33 | 3300 | 200 | 700 | 67 | 31 | 38 | 935 |

**EXHIBIT 1.6**
**MOTOR CONTROL PANEL & ACCESSORIES**
**440 VOLT, 880 VOLT, 1500 VOLT, 2500 VOLT**
**DESCRIPTION**

## SINGLE-PHASE, OIL IMMERSED SELF COOLED TYPE TRANSFORMERS

**TRANSFORMERS ARE AVAILABLE IN THE PRIMARY VOLTAGES OF 2400/4160 Y; 7200/12,470 Y; 13,200; 14,400/24,940 Y.**

| KVA SIZE | SECONDARY VOLTAGE | HEIGHT | WIDTH | DEPTH | WEIGHT |
|---|---|---|---|---|---|
| 28 | 625/1750 | 36" | 21" | 24" | 400# |
| 37.5 | 625/1750 | 39" | 23" | 26" | 550# |
| 50 | 625/1750 | 45" | 23" | 26" | 670# |
| 75 | 625/1750 | 49" | 28" | 29" | 980# |
| 75 | 1900/2500 | 49" | 28" | 29" | 980# |
| 100 | 625/1750 | 49" | 33" | 29" | 1,125# |
| 100 | 1900/2500 | 49" | 33" | 29" | 1,125# |

NOTE: Secondary voltages above are those obtained with Delta connected secondary. Taps are provided for numerous intermediate voltages. Additional secondary voltages can be obtained by WYE connecting the secondary.

## THREE PHASE AUTO TRANSFORMERS, OIL IMMERSED SELF COOLED.

| | | | SECONDARY AMPS | | DIMENSIONS | | | |
|---|---|---|---|---|---|---|---|---|
| KVA | PRIMARY VOLTAGE | SECONDARY VOLTAGE | FROM H.V. TAP SETTING | TO L.V. TAP SETTING | HEIGHT | WIDTH | DEPTH | WEIGHT |
| 50 | 440/460/ | 750-1050 | 27 | 38 | 33" | 27" | 28" | 650# |
| 50 | 480 | 800-1250 | 23 | 36 | | | | |
| 75 | " | 800-1250 | 35 | 55 | 33" | 27" | 32" | 900# |
| 75 | " | 850-1450 | 30 | 51 | | | | |
| 100 | " | 850-1450 | 40 | 68 | 37" | 35" | 32" | 1120# |
| 125 | " | 850-1450 | 50 | 85 | 37" | 35" | 34" | 1250# |
| 150 | " | 850-1450 | 60 | 102 | 42" | 33" | 34" | 1499# |
| 200 | " | 850-1450 | 80 | 136 | 43" | 40" | 37" | 1880# |
| 250 | " | 850-1450 | 100 | 170 | 43" | 40" | 37" | 1920" |

NOTE:

1. Pole hangers not available for 200 & 250 KVA.
2. Voltage steps are 50 V on 750-1050, 75 V on 800-1250 and 100 V on 850-1450 secondary voltages. However, intermediate voltages are available by taking advantage of the three primary taps.

**EXHIBIT 1.7**
**TRANSFORMERS**

| DESCRIPTION (TYPE) | CASING SIZE (O.D.) | TUBING SIZE (O.D.) | MAXIMUM RECOMMENDED LOAD (LBS) | WEIGHT (LBS) |
|---|---|---|---|---|
| A | 5 1/2" | 2 3/8" | 30,000 | 57 |
| | | 2 7/8" | 30,000 | 57 |
| | 6 5/8", 7" | 2 3/8" | 30,000 | 70 |
| | | 2 7/8" | 30,000 | 70 |
| B | 5 1/2", 7" | 2 3/8" | 80,000 | 147 |
| | | 2 7/8" | 80,000 | 147 |
| | 7" | 3 1/2" | 80,000 | 146 |
| | 8 5/8" | 2 3/8" - 3 1/2" | 100,000 | 197 |
| | | 4 1/2" | 100,000 | 191 |
| | | 5 1/2" | 100,000 | 191 |
| | 9 5/8", 10 3/4" | 2 3/8" | 100,000 | 267 |
| | | 2 7/8" | 100,000 | 267 |
| | | 3 1/2" | 100,000 | 267 |
| | | 4 1/2" | 100,000 | 264 |
| | | 5 1/2" | 100,000 | 264 |
| | | 6 5/8" | 100,000 | 264 |

**EXHIBIT 1.8**
**TUBING HEADS**
**RATING, SPECIFICATIONS**

| 3KV ROUND CABLE W/I-WIRE | | | | | | | |
|---|---|---|---|---|---|---|---|
| CONDUCTOR SIZE | CONDUCTOR MATERIAL | CONDUCTOR CONST. | INSULATION | JACKET | ARMOR | PART NUMBER | WT. LBS PER FOOT |
| #1 | Copper | Stranded | PPE | Nitrile | Galv. Stl. | A2638437 | 1.88 |
| #2 | Copper | Stranded | PPE | Nitrile | Galv. Stl. | A2638436 | 1.62 |
| #4 | Copper | Solid | PPE | Nitrile | Galv. Stl. | A2638434 | 1.15 |
| #6 | Copper | Solid | PPE | Nitrile | Galv. Stl. | A2638435 | .88 |
| #4 | Copper | Solid | PPE | * | * | A2641415 | .52 |
| #6 | Copper | Solid | PPE | * | * | A2641416 | .44 |
| **3KV ROUND CABLE WITHOUT I-WIRE** | | | | | | | |
| #4 | Copper | Solid | PPE | Nitrile | Galv. Stl. | A2642201 | 1.15 |
| #6 | Copper | Solid | PPE | Nitrile | Galv. Stl. | A2642202 | .88 |

* High Density Polyethylene

| 3KV FLAT CABLE | | | | | | | |
|---|---|---|---|---|---|---|---|
| #1 | Copper | Solid | PPE | Nitrile | Galv. Stl. | A2640131 | 1.72 |
| #1 | Copper | Solid | EPR | ** | Galv. Stl. | A2640132 | 2.60 |
| #2 | Copper | Solid | PPE | Nitrile | Galv. Stl. | A2641234 | 1.48 |
| #2 | Copper | Solid | EPR | ** | Galv. Stl. | A2641235 | 2.26 |
| #4 | Copper | Solid | PPE | Nitrile | Galv. Stl. | A2638789 | 1.06 |
| #4 | Copper | Solid | EPR | ** | Galv. Stl. | A2638438 | 1.69 |

** Lead w/Nylon Braid

**EXHIBIT 1.9**
**CABLE SPECIFICATIONS**

| EQUIPMENT SERIES | CASING O.D. (INCHES) | CASING WEIGHT (#/FT) | NOMINAL I.D. | *MAXIMUM ARMORED CABLE SIZE RECOMMENDED WITH VARIOUS TUBING SIZES (O.D.) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | API EXTERNAL UPSET | | | API NON-UPSET | | | | |
| | | | | NOMINAL O.D. | 2 3/8 | 2 7/8 | 3 1/2 | 2 3/8 | 2 7/8 | 3 1/2 | 4 1/2 | 5 1/2 |
| | | | | COUPLING O.D. | 3.063 | 3.668 | 4.500 | 2.875 | 3.500 | 4.250 | 5.200 | |
| I | 5½ | 14 | 5.012 | | 1 | 6 | -- | 1 | 4 | -- | -- | -- |
| | | 15.5 | 4.950 | | 1 | 6 | -- | 1 | 4 | -- | -- | -- |
| | | 17 | 4.892 | | 1 | 6 | -- | 1 | 6 | -- | -- | -- |
| | | 20 | 4.778 | | 1 | -- | -- | 1 | 6 | -- | -- | -- |
| II | 6 5/8 | 17 | | | 1 | 1 | 6 | 1 | 1 | 4 | -- | -- |
| | | 20 | 6.049 | | 1 | 1 | 4 | 1 | 1 | 4 | -- | -- |
| II | 7 | 17 | 6.538 | | 1 | 1 | 1 | 1 | 1 | 1 | -- | -- |
| | | 20 | 6.456 | | 1 | 1 | 1 | 1 | 1 | 1 | -- | -- |
| | | 23 | 6.366 | | 1 | 1 | 1 | 1 | 1 | 1 | -- | -- |
| | | 26 | 6.276 | | 1 | 1 | 1 | 1 | 1 | 1 | -- | -- |
| | | 29 | 6.184 | | 1 | 1 | 1 | 1 | 1 | 1 | -- | -- |
| | | 32 | 6.094 | | 1 | 1 | 2 | 1 | 1 | 1 | -- | -- |
| II | 8 5/8 | 49 | 7.511 | | 1 | 1 | 1 | 1 | 1 | 4 | 1 | 1 |

*Contact Factory if larger size cable is required. Parallel cable of various dimensions is available on special order.

MAXIMUM DIAMETER OF UNITS (INCHES)

| SERIES | MOTOR | PUMP | MOTOR SEAL CHAMBER | FLAT CABLE | CABLE BANDS | MAX. DIA. WITH GUARDS | MAX. DIA. LESS CABLE GUARDS |
|---|---|---|---|---|---|---|---|
| I | 4.500 | 4.00 | 4.00 | .450 | .030 | 4.770 | 4.730 |
| II | 5.625 | 5.375 | 5.375 | .485 | .030 | 6.055 | 6.015 |

CABLE INFORMATION

| CABLE SIZE | WEIGHT LBS/FT | | DIAMETER | | CIRCULAR MILS PER CONDUCTOR |
|---|---|---|---|---|---|
| | ARMORED | UNARMORED | ARMORED | UNARMORED | |
| 1 | 1.75 | -- | 1.40 | -- | 83,400 |
| 2 | 1.50 | -- | 1.32 | -- | 66,200 |
| 4 | 1.10 | .64 | 1.14 | .92 | 41,640 |
| 6 | .82 | .46 | 1.00 | .76 | 26,250 |
| 8 | .65 | .29 | .94 | .71 | 16,500 |

**EXHIBIT 1.10**
**EQUIPMENT COMBINATIONS IN VARIOUS CASING SIZES**

## FLAT CABLE EXTENSIONS

| MOTOR SERIES | ARMOR | WIRE SIZE | TYPE | WIDTH | LENGTHS AVAILABLE | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 25' | 40' | 50' | 60' | 75' | 100' |
| I | Bronze | 6 | 3 KV Hi-Duty | .450 | X | X | | X | X | X |
| I | Monel | 6 | 3 KV Hi-Duty | .450 | X | X | | X | X | X |
| II | Bronze | 5 | 3 KV Hi-Duty | .485 | X | X | X | | | |
| II | Monel | 5 | 3 KV Hi-Duty | .485 | X | X | X | | | |
| II | Monel | 4 | 3 KV Hi-Duty | .527 | X | | | | X | |

## SURFACE CABLE

Surface cables are required to connect power line to motor control panel or motor control panel to submersible cable. Units include connectors on each end.

| SIZE | WEIGHT (LBS/FT) | DIA (INCHES) | 3 KV SURFACE CABLE | | | |
|---|---|---|---|---|---|---|
| | | | NEW | | USED | |
| | | | 50 FOOT UNIT | PRICE PER ADDITIONAL FOOT | 50 FOOT UNIT | PRICE PER ADDITIONAL FOOT |
| 1 | 1.75 | 1.40 | X | X | X | X |
| 2 | 1.50 | 1.32 | X | X | X | X |
| 4 | 1.10 | 1.14 | X | X | X | X |
| 6 | 0.82 | 1.00 | X | X | X | X |

**EXHIBIT 1.11**
**FLAT CABLE AND SURFACE CABLE SPECIFICATIONS**

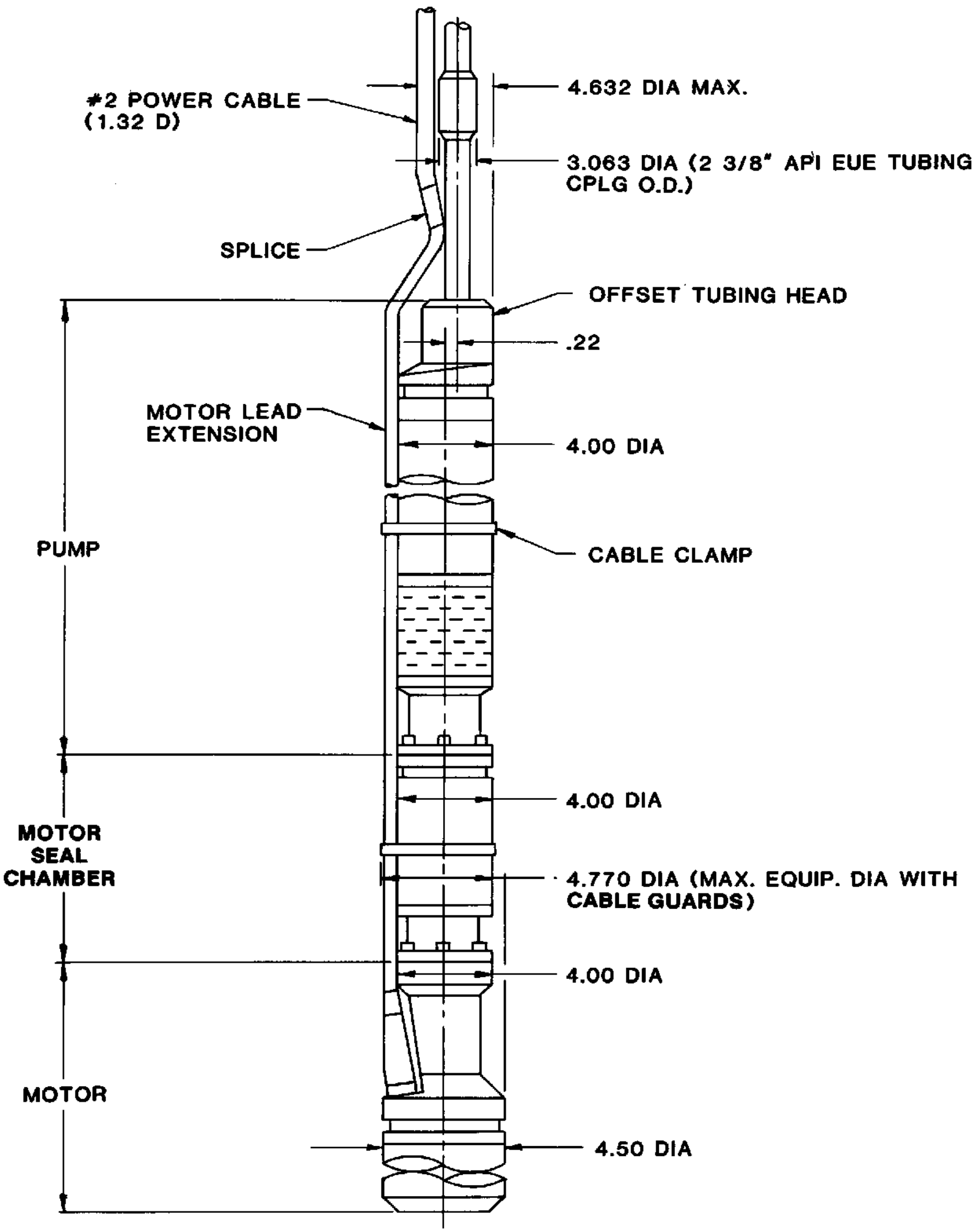



**EXHIBIT 1.12**
**DOWNHOLE EQUIPMENT WITH OFFSET TUBING HEAD**

A. WELL DATA

1. Well No. & Field Name **EXAMPLE PROBLEM NO. 2** Date
2. Well Location (County, State, Other) **Oil & Water w/gas**
3. Installation New **(X)** or Redesign ( )
4. Producing Formations **Devonian**
5. Formation Type (Sandstone, Limestone, Other) **Dolomite Limestone**
6.*API Casing **5.5** In. O.D.: **15.5 & 17** #/Ft. Surface Ft. TO **10,000** Ft.
7.*Liner **NONE** In. O.D.: #/Ft. Ft. TO Ft.
8.*Other Limiting Dimensions **NONE** In. I.D. Ft. TO Ft.
9.*Open Hole **NONE** Ft. TO Ft.
10.*Total Depth **10,000** Ft. Plugged Back Depth **9960** Ft.
11.*Perforated Intervals **9800** Ft. TO **9840** Ft.
**9800** Ft. TO **9900** Ft.
12.*Wellhead Type
13.*API Tubing **$2\frac{3}{8}$** In. O.D. **8 Rd EUE** Threads **J-55** Grade

B. RESERVOIR DATA (FROM TEST & PRODUCTION DATA)

1.*Present Production **250 BFPD (50 BO, 200 BW)** Pumping **(X)** Swabbing ( ) Flowing ( )
2. Bottom Hole Static Pressure **4000** PSIG AT: **9880** Ft.
3. Bottom Hole Producing Pressure **3300** PSIG AT: **250** BFPD **Calculated (not dependable)**
PSIG AT: BFPD
4. GOR **440** **total** S.C.F./S.T.B. **GOR through pump = 200 SCF/STB**
5.*Water Cut **80** %
6. Oil API Gravity **37** °API **0.840** SP.GR.°
7. Bottom Hole Temperature **190°F**
8. Water Specific Gravity **1.06**
9. Gas Specific Gravity **0.68**
10. Oil Viscosity (1) CP.OR **40** SSU At **190** °F
(2) CP.OR SSU At °F
11. PVT Data **NONE** Solution GOR FVF PSIG
Solution GOR FVF PSIG
Solution GOR FVF PSIG
Solution GOR FVF PSIG
12. Bubble Point Pressure **2000** PSIA

C. SIZING SPECIFICATIONS

1.*Desired Production **1100** BFPD **220** BOPD **880** BWPD
2. Desired Pump (Intake) Vertical Setting Depth **9000** V.D. Ft. **9000** M.D.
3. Desired Pump (Intake) Pressure **500** PSIG
4. Required Wellhead Pressure **100** PSIG
5. Gas Through Pump
6. Primary Voltage Available **22,000** Volts **60** Hertz
7. Casing Pressure **25** PSIG
8. Special Problems: **NONE** Sand ( ) Scale ( ) Corrosion ( ) Paraffin ( ) $H_2S$ ( ) $CO_2$ ( )

REMARKS: **Operator desires stainless steel bands, three single phase transformers and no check no drain valve.**

NOTE:

BY: ______________________ DATE: ______________________

*Indicates Data That Must Be Provided

**EXHIBIT 2.1**
**ELECTRIC SUBMERSIBLE PUMP**
**WELL DATA SHEET**

## A. WELL DATA

| | | | | | | |
|---|---|---|---|---|---|---|
| 1. Well No. & Field Name | EXAMPLE PROBLEM NO. 3 | | | | | Date 2/09/83 |
| 2. Well Location (County, State, Other) | Viscosity Correction — Medium | | | | | |
| 3. Installation | | | | New (X) | or | Redesign ( ) |
| 4. Producing Formations | | | | | | |
| 5. Formation Type (Sandstone, Limestone, Other) | | | | | | |
| 6.*API Casing | 5.5 In. O.D.: | 17 #/Ft. | Ft. TO | 5600 Ft. | | |
| 7.*Liner | In. O.D.: | #/Ft. | Ft. TO | Ft. | | |
| 8.*Other Limiting Dimensions | | In. I.D. | Ft. TO | Ft. | | |
| 9.*Open Hole | | | Ft. TO | Ft. | | |
| 10.*Total Depth 5600 | Ft. Plugged Back Depth | | | 5400 Ft. | | |
| 11.*Perforated Intervals | | | 5300 Ft. TO | 5400 Ft. | | |
| | | | Ft. TO | Ft. | | |
| 12.*Wellhead Type & Size | | | | | | |
| 13.*API Tubing | 2⅜ In. O.D. 8 Rd. EUE | Threads | J-55 | Grade | | |

## B. RESERVOIR DATA (FROM TEST & PRODUCTION DATA)

| | | | | | |
|---|---|---|---|---|---|
| 1.*Present Production | BOPD | BWPD | 300 BFPD | Pumping (X) | Flowing ( ) |
| 2. Bottom Hole Static Pressure | 1700 PSIG AT: | 5350 Ft. | | | |
| 3. Bottom Hole Producing Pressure | 1200 PSIG AT: | 300 BFPD | | | |
| | PSIG AT: | BFPD | | | |
| 4. GOR 50 | S.C.F./S.T.B. | | | | |
| 5.*Water Cut | 20.0% | | | | |
| 6. Oil API Gravity | 15.0 °API | | | | |
| 7. Water Specific Gravity | 1.06 | | | | |
| 8. Gas Specific Gravity | | | | | |
| 9. Bottom Hole Temperature | 140°F | | | | |
| 10. Oil Viscosity (1) Not Avail. | CP.OR | SSU At | 195 °F | | |
| (2) | CP.OR | SSU At | °F | | |
| 11. PVT Data | Solution GOR | FVF | PSIG | | |
| | Solution GOR | FVF | PSIG | | |
| | Solution GOR | FVF | PSIG | | |
| | Solution GOR | FVF | PSIG | | |
| 12. Bubble Point Pressure | PSIG | | | | |

## C. SIZING SPECIFICATIONS

| | | | | | | |
|---|---|---|---|---|---|---|
| 1.*Desired Production | 800 STB | BFPD | 640 BOPD | 160 BWPD | | |
| 2. Desired Pump (Intake) Vertical Setting Depth | | | 5200 Ft. | | | |
| 3. Desired Pump (Intake) Pressure | | | 300 PSIG | | | |
| 4. Required Wellhead Pressure | | | 50 PSIG | | | |
| 5. Gas Through Pump | | | % (Of Total Gas) | | | |
| 6. Primary Voltage Available | 14,400/24,940 | Volts | 60 Hertz | | | |
| 7. Casing Pressure | | | PSIG | | | |
| 8. Special Problems: | Sand ( ) | Scale ( ) | Corrosion ( ) | Paraffin ( ) | $H_2S$ ( ) | $CO_2$ ( ) |

REMARKS: **Operator desires monel bands, coated equipment, three single phase transformers. No check or drain valve.**

BY: ______________________ DATE: ______________________

*Indicates Data That Must Be Provided

**EXHIBIT 3.1**
**ELECTRIC SUBMERSIBLE PUMP**
**WELL DATA SHEET**

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