ENGINEERED APPLICATION OF SUBMERGIBLE PUMPS

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INTRODUCTION

This paper presents the basic concepts of systematically engineered selections of submergible electric pumping systems. The adaption of the basic design principles to a number of different application concepts is reviewed and the effects on pump performance of produced fluid properties, particularly viscosity and ingested free gas are discussed.

DESCRIPTION OF EQUIPMENT

The major components of a submergible pumping system are motor, protector, pump intake, pump, cable and switchboard. Figure 1 shows the downhole equipment in a typical well application.

Motor

The submergible motor is an oil-lubricated, two-pole induction electric motor. The rotor is supported by a thrust bearing which is lubricated by the motor oil. Cooling is maintained by heat transfer to the produced fluid in the annulus. Thus, it is critical that fluid movement at a recommended minimum rate of one foot per second past the motor is maintained. As the result of close tolerances, small air gap, and geometric configuration resulting in minimal end losses, the natural power factor and operating efficiency are typically very high averaging approximately 0.83 at full load, 3500 RPM, operating speed. Submergible motors have been successfully operated in ambient temperatures in excess of 300°. These motors are available in a range of diameters and horsepowers to accommodate a wide variety of applications:

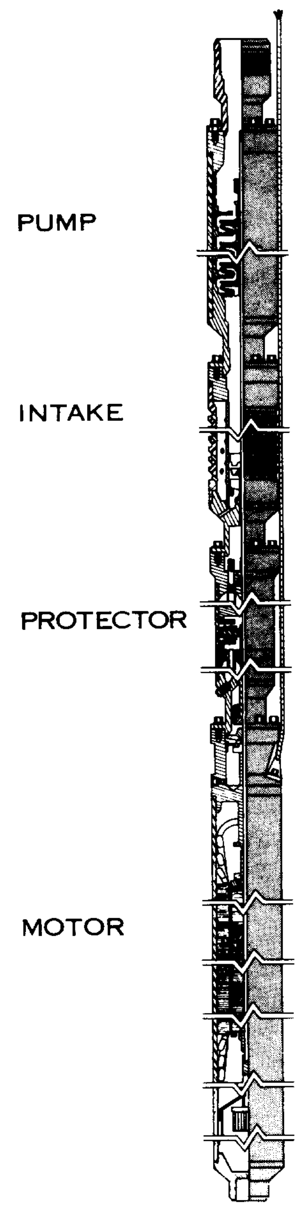

FIG. 1—STANDARD "OILWELL TYPE" SUBMERGIBLE ELECTRIC PUMP

Motor Diameter, In.	Maximum Horsepower
3.75	127.5
4.56	240.0
5.40	600.0
7.38	720.0

Protector

This component is installed between the motor and the pump. It provides a fluid barrier which prevents the migration of the produced fluid into the motor while simultaneously allowing pressure communication across the protector. This fluid seal thus assures equalized pressures between the inside of the motor and the wellbore which is a critical factor in the electrical cable pothead integrity. The protector chambers allow for motor oil thermal expansion as the motor oil temperature first rises during installation and then additionally rises to the operating temperature after start-up. The protector also houses the main thrust bearing which absorbs any upthrust or downthrust transmitted through the pump shaft.

Intake Section

This unit provides the path of fluid entry into the pump. It is designed to maximize the gas separation in the annulus and to insure the optimum gas-lock free charging of the lowest pump stages through the use of a specially designed charge propeller in the base of the unit.

Pump

The multistage centrifugal pump is offered in a wide variety of diameters with capacity ranges from 200 BPD to over 60,000 BPD and in lift capacities up to 15,000 feet. Through the use of corrosion resistant materials, (cast Ni-resist or moulded nonmetallic polyphenylene sulfide impellers and diffusers with K-monel shafting; all as standard equipment) pump wear and corrosion are minimized and long-term predictable performance in all normally encountered fluids is assured. Due to the hydraulic limitations associated with the diameter limitation, the lift per stage is relatively low. However, as many as 500 or more stages have been run to meet high head requirements.

Power System

The three-phase power to drive the motor is transmitted by a cable from the surface connecting to the motor through the flat cable extension at the pothead. The cable is strapped to the tubing which supports the unit. The operation of the motor is controlled by the switchboard which includes safety controls and protection devices which sense overload or pumped-off conditions and thus offer a high degree of motor protection. The suppliers of a submergible pumping system can furnish total systems with single responsibility.

CONVENTIONAL SYSTEM DESIGN

Conventional design is commonly associated with water design parameters. This section will review the basic data required for the selection of a normal system and will present a sample calculation.

Determine Productivity

It is imperative that the well's capability to produce be defined as accurately as possible. By far, the principle cause of disappointing pump performance is misapplication due to the actual productivity being significantly different from the design estimates. Basic data most commonly supplied is a static liquid level or pressure ($P_{\overline{R}}$), a producing liquid level or pressure (Pwf) and the associated producing rate (q_o). This data can be used to project the well's performance by two commonly applied methods.

1. Straight-line Productivity Index (PI)

$$PI = \frac{q_o}{P_{\overline{R}} - P_{wf}} \quad \text{or} \quad PI = \frac{q_{o2} - q_{o1}}{P_{wf1} - P_{wf2}} \text{ BPD/psi}$$

2. Vogel[1] Inflow Production Rate (IP_R)

This technique presents a theoretically derived statistical correlation between

$$P_{wf}/P_{\overline{R}} \text{ versus } q_o/q_{o,\,max}:$$

$$\frac{q_o}{q_{o,\,max}} = 1 - 0.2\,\frac{P_{wf}}{P_{\overline{R}}} - 0.8\,\frac{P_{wf}^2}{P_{\overline{R}}^2}$$

This correlation was derived from solution gas-drive reservoir parameters. However, it has been well proven that the technique has considerable practical validity when applied to water-drive reservoirs.

Figure 2 presents a plot of the results of the two techniques using the following basic data. This figure assumes a consistent fluid gradient in the annulus; and thus, the producing and the static liquid levels are proportional to Pwf and $P_{\bar{R}}$

Well Test (q_o)	400 BPD
Producing Liquid Level f (P_{wf})	2700 ft
Static Liquid Level f ($P_{\bar{R}}$)	2000 ft
Midpoint of the Producing Zones	7000 ft

Figure 2 clearly shows that the well performance at large withdrawal rates will vary considerably depending on the analysis technique used. As expected, the Vogel correlation will result in a more conservative design. Whether these simple productivity calculations are used or if any of the more complex and sophisticated reservoir engineering techniques are applied, the basic validity of the calculation and ultimately the system design depends on the selection and critical interpretation of the basic production test and pressure data.

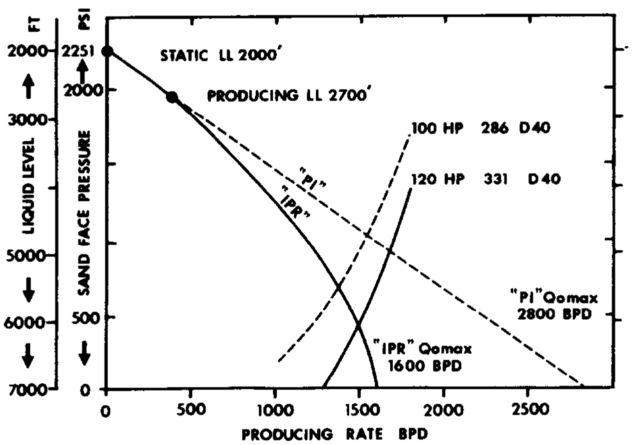

FIG. 2—PRODUCTIVITY AND PUMP PERFORMANCE FOR THE SAMPLE DATA AND PUMP SELECTION

Calculate Total Dynamic Head (TDH)

The second step in basic pump design is the calculation of TDH. This is the net lift, measured in feet, that the pump must produce at a given rate to satisfy the mechanical and hydraulic requirements of the system. TDH is the sum of three components:

Net Lift measured from the producing liquid level to surface.

Friction Losses in the tubing.

Surface Pressure.

Using the same productivity parameters and by further defining the mechanical system, we can calculate the TDH for the typical design.

Productivity (From IPR)	1500 BPD
Producing Liquid Level	6000 ft
Surface Pressure	100 psi
Tubing Size	2-7/8 in. OD EUE
Produced Specific Gravity	1.05

1. Net Lift: The net lift is the vertical lift from the producing liquid level to the surface. Note that the pump intake could be located between the top of the producing zones, and approximately 6250 ft. As long as no significant volume of free gas enters the pump intake and nominal NPSH is maintained, the pump-setting depth has no direct bearing on net lift.
2. Friction Loss: This component of TDH is typically calculated from standard correlation charts (e.g., Hazen and Williams, C = 120) that are included in the submergible pump catalogue. In this example, a setting depth of 6500 ft would be appropriate and using a chart as previously described, the friction loss, measured in feet would be:

$$\text{Friction Loss} = \frac{6500 \text{ ft}}{1000 \text{ ft}} \times 18 \; \frac{\text{Ft Loss}}{1000 \text{ ft}} = 117 \text{ ft}$$

3. Surface Pressure: This data is typically presented in psi based on field experience or on anticipated surface system design. It must be corrected for specific gravity and converted to feet. For this example, the surface pressure was 100 psi.

$$\text{Surface Pressure (ft)} = 100 \text{ psi} \times 2.31 \text{ ft/psi} \times 1/1.05 = 222 \text{ ft}$$

$$\text{TDH} = \text{Net Lift} + \text{Friction Loss} + \text{Surface Pressure} = 6339 \text{ ft}$$

Pump Selection

After calculating the TDH and knowing the casing size, the pump type can be selected and number of stages determined. The casing size determines the series, or largest outside diameter of the pump and motor that can be used. Each pump chart lists the smallest OD casing in which the pump can normally be run.

Assuming 5-1/2 in. 15.5 lb/ft casing for this example, the alternatives would be "A" type, 338 series (3.38 in. OD) or "D" type, 456 series (4.56 in. OD) pumps. In general, the larger diameter system is more efficient and less expensive.

1. Select "D" 400 series pump type
   Rate = 1500 BPD
   Select D-40 Recommended Range 950 BPD to 1800 BPD. Pump stages are designed to be in hydraulic balance near the peak efficiency. The recommended range, on the pump curve which is shaded in Fig. 3, defines these limits. Pumps will operate in downthrust to the left of the recommended range or operate in upthrust to the right of the recommended range. Mechanical wear due to imbalance can shorten the pump life and the protector thrust bearing load will be significantly increased.
2. Read the pump operating parameters at the projected rate of 1500 BPD for the D-40 pump from Fig. 3.
   Head/100 stages = 1930 ft of 19.3 ft/stage.
   Horsepower/100 stages = 35 Hp or 0.35 Hp /stage.
3. Calculate pump stages and horsepower required.

   $$\text{No. Stages} = \frac{\text{TDH}}{\text{Head/Stage}} = \frac{6339}{19.3} = 328 \text{ stage}$$

   HP Required = No. of stages x Hp/Stage x Specific Gravity

   HP = 328 Stages x 0.35 Hp/Stage x 1.05 = 120.5 Hp
4. Select full-housing pump and motor
   Pump - 331 Stage D-40
   Motor 120 Hp 456 Series
   The performance of this system can be calculated at other producing rates using the head per stage at these rates, times the number of stages to determine the TDH. The correlation of the LL (TDH - Friction Loss - Surface Pressure) versus Producing Rate can then be calculated and presented as on Fig. 2. Alternate systems, such as a 100 Hp system can also be presented for comparison.
5. Select the motor voltage, cable type and switchboard that will minimize the system investment. In many cases, the selection of motor operating voltage, which determines the cable, switchboard, and transformer sizes, can significantly affect the total system cost.

120 Hp Motor Voltage	Cable Type	Switchboard Rating	Total System Cost*
1350 V	#4 Flat	150HP-1500V	41,000
2300 V	#6 Round	600HP-2400V	37,000

*Includes all downhole equipment except tubing, wellhead switchboard, and transformers.

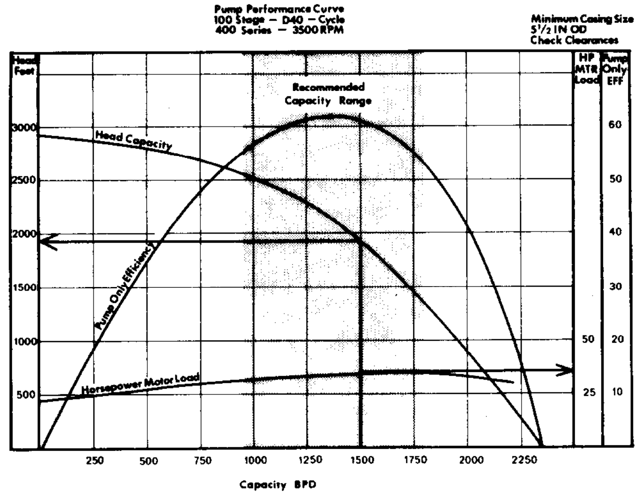

FIG. 3—PUMP PERFORMANCE FOR D-40 PUMP

ALTERNATE USES OF THE BASIC SYSTEM SELECTION

The example system consisting of a 120 Hp 331 Stage D-40 was designed to produce 1500 BPD at a TDH of 6339 with a setting depth of 6500 ft. While it may appear academic, the fact is that the same motor and pump can be economically utilized in a number of different applications. The aspect most often overlooked or taken for granted is that the major component of TDH is the net lift. This need not be the case as the pump will produce at the same rate against any combination of TDH components so long as the total remains the same.

Surface Injection or Booster

If the example system, when utilized on the surface, is installed in a concentric can consisting of an outer casing and inner shroud. This configuration is required to route the produced fluid by the motor for cooling. For surface application, the net lift is zero, the friction loss is essentially zero and all of the TDH is converted to a pressure difference across the pump. With flooded suction conditions, this is the surface pressure; however, in booster pump applications, pressures as high as 8000 psi or more could be achieved depending on the intake pressure. The sample pump output in this type of use would be:

120 Horsepower 331 D-40 System

Rate (BPD)	TDH	Δ PSI
1000	8341	3791
1250	7580	3445
1500	6388	2904
1750	4822	2196

System Cost (exclusive of casing, casing head and one tubing joint) = $22,000

Production/Injection

Many systems are now being designed to utilize one pump to produce a water supply well and provide sufficient surface injection pressure to meet the injection system demands. For example:

331 D-40 System
Producing LL 2000 ft
Setting Depth 2500 ft

Rate (BPD)	Surface Pressure (psi)
1000	2872
1250	2522
1500	1974
1750	1261

System cost is $32,200. The cost of a 50 Hp system required to lift the production from 2000 ft and deliver at 50 psi to a surface plant would be $21,000. Thus, for an additional investment of $11,200 the capability of injecting approximately 1500 BPD at nearly 2000 psi can be added.

This system has the further advantage of being noiseless, safe (no surface moving parts) and easily regulated.

FACTORS AFFECTING PUMP PERFORMANCE

The principal factors that can significantly affect submergible pump performance can be divided into electrical, which will affect motors, and mechanical, which will affect pumps. This discussion will point out the two fluid conditions which will most readily cause pumps to deviate from standard "water" designs.

Viscosity of Produced Fluid

Historically, viscosity has been of minor importance in domestic pump selection as typical submergible applications were confined to high water-cut wells or water-source wells. However, the effect of viscosity has been well-identified by foreign operators who are typically pumping very low water-cut wells.

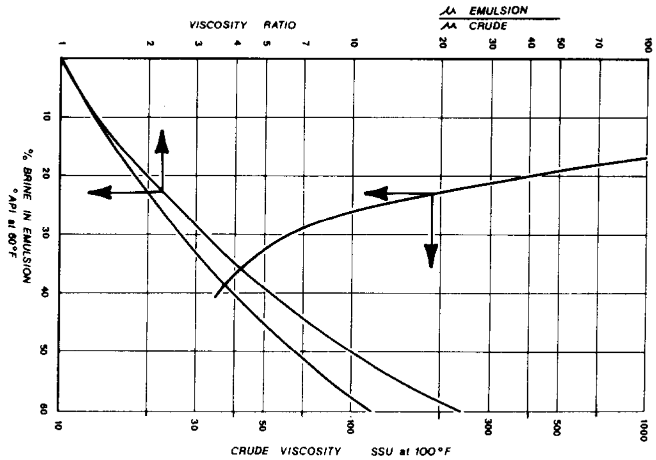

FIG. 4—CRUDE OIL VISCOSITY VS. API OIL GRAVITY AND EMULSION-TO-CRUDE VISCOSITY RATIO VS. PERCENT BRINE

Figure 4 presents a standard correlation of viscosity versus °API for a broad spectrum of crude oils. This figure also presents a correlation of emulsion/crude viscosity ratio versus percent water-cut. This last correlation is of particular note as it indicates that as water-cuts approach 60%, a tight water-in-oil emulsion could have a viscosity of 10-24 times the viscosity of the crude oil. As the water-cut increases, typically between 60 and 70%, emulsion will break to an oil-in-water and the viscosity of the emulsion will be reasonably close to water.

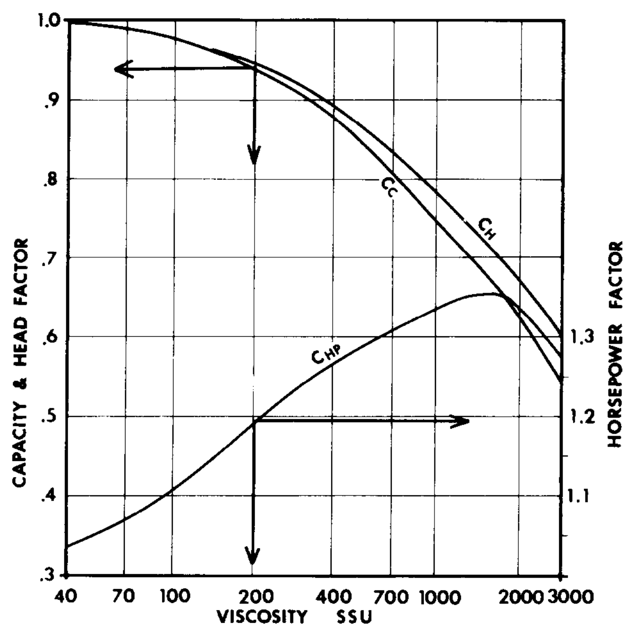

FIG. 5—VISCOSITY CORRECTION FACTORS FOR HEAD, CAPACITY AND HORSEPOWER (HYDRAULICS INSTITUTE DATA)

Figure 5 presents correction factors which can be applied to water parameters to correct head, capacity and horsepower for the effect of viscosity. To summarize the effect of viscosity on pump performance, the following table adjusts the pumping parameters of the sample water design for two emulsified water/oil mixtures.

ADJUSTED PERFORMANCE FOR 331 D-40 PUMP

°API	Water	35°	20°
Oil Viscosity SSU @ BHT (140°)	30	25	400
Percent Water Cut	100	50	50
Viscosity Ratio	–	8	8
Emulsion Viscosity	–	200	3200
Correction Factors			
CP	1.0	0.94	0.484
CH	1.0	0.94	0.522
CHP	1.0	0.19	1.20
Corrected Productivity Rate BPD	1500	1410	726
Corrected TDH	6330	5950	3304
Corrected HP	120	132	139

In practice, the heat dissipated by the motor and pump will increase the produced fluid temperature and mitigate the effects of viscosity. Further, de-emulsifiers can be injected into the system to break the emulsion. In cases where very high viscosities are anticipated, the pump company technical staff and pump design engineers can be of major assistance in providing more sophisticated selections, often utilizing unpublished proprietary information.

Ingested Free Gas

The effects of the free gas that is produced through a submergible pump can be dramatic in gassy high oil-cut wells, particularly at low intake pressures. Often, as much as 50% of the intake capacity of the lowest stage is occupied by free gas. In these cases, the lower stages of the pump will be pumping a gas/liquid mixture of relatively low specific gravity. The head output of these stages is a function of the total fluid rate (oil, water and free gas) moving through the stage. The ΔP across the stage is a function of the average specific gravity of the three-phase mixture, calculated at the pressure and temperature at that stage. In essence, the lower stages of a submergible pump will function as a compressor, increasing the pressure until the free gas either goes into solution in the oil phase or is compressed to a negligible volume. At this point, the upper stages function normally with a liquid flow. To complicate matters, the compressed and solution gas will expand in the tubing creating considerable gas lift effect.

Figure 6 presents plots of the performance of the example 331 D-40 pump with water and with various gas-oil ratios at a water-cut of 75%. It is apparent that to maintain a given surface-measured total liquid producing rate, the intake pressure must be increased to accommodate increasing volumes of gas; or at a constant intake pressure, the total liquid production will rapidly decline as the GOR increases. The total fluid intake volumes for the conditions illustrated in Fig. 6 are typically over 2000 BPD, so while the 331 D-40 could operate under the conditions postulated, it would not be a good choice.

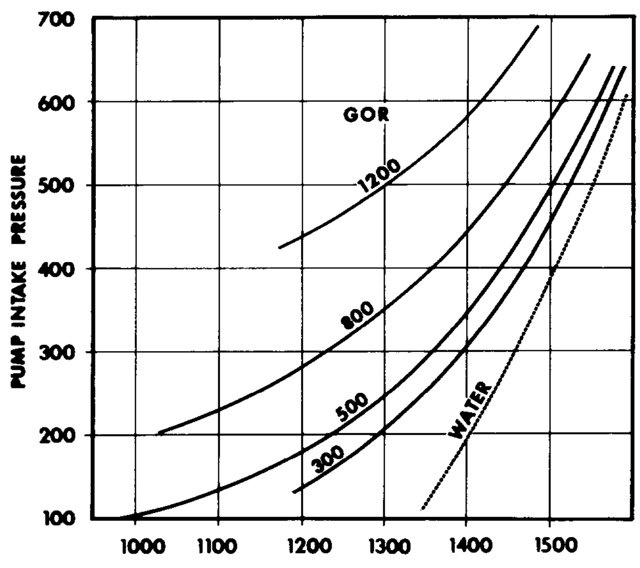

FIG. 6—EFFECT OF GOR ON PUMP PERFORMANCE (ASSUME 50% OF FREE GAS ENTER INTAKE)

To optimize the selection of pumps, a computer program has been developed.[2] This software package will select a pump configuration based on the IPR, PVT and mechanical parameters of a gassy and/or viscous well. The program has three major design phases:

1. INPUT CAPACITY CALCULATIONS. This section utilizes "PI" data, "IPR" data or given information together with PVT and GOR data to determine the volume of the oil,

water and free gas that will enter the intake section at the intake pressure and temperature. The free gas volume is very sensitive to intake pressure, so valid productivity data is very important.

2. TUBING PRESSURE DROP. This section calculates from the required surface fluid requirements, the pump discharge pressure required to lift the fluid to surface. The Orkuyski[3] technique is used to calculate this pressure drop across the tubing and account for the multiphase gas lift effects. This calculation is very sensitive to surface pressure, so extreme care must be utilized in the selection of this factor.
3. PUMP SELECTION. Knowing the intake rate and pressure and the required output rate and pressure, the program selects the optimal pump to meet these requirements. Very often, two or three different capacity stage types are used to make up a tapered, in a capacity sense, pump. If we assumed the same IPR data and mechanical configuration, with the exception of lowering the pump to 6900 ft, but changed the fluid to 35° API oil and the GOR to 500, the computer would select the following:

Pump Type	Lower Section 63 D-82
	Upper Section 154 D-55
Intake Pressure, psi	470
Wellhead Pressure, psi	100
Free Gas Percentage Into Pump	50%
Intake Fluid Volume - Bbl	3153
Discharge Fluid Volume - Bbl	1913
Stock Tank Barrels (Oil and Water)	1510
Discharge Pressure, psi	1666
Horsepower	75

It is important to note that the intake fluid volume is approximately twice the surface volume. The required horsepower at stabilized conditions is 75 Hp, only 62.5% the water horsepower of 120 Hp. This is due to the specific gravity and the gas lift effect.

Figure 7 profiles the total fluid producing rate, specific gravity and pressure from the intake conditions at the D-82 to the discharge from the D-55.

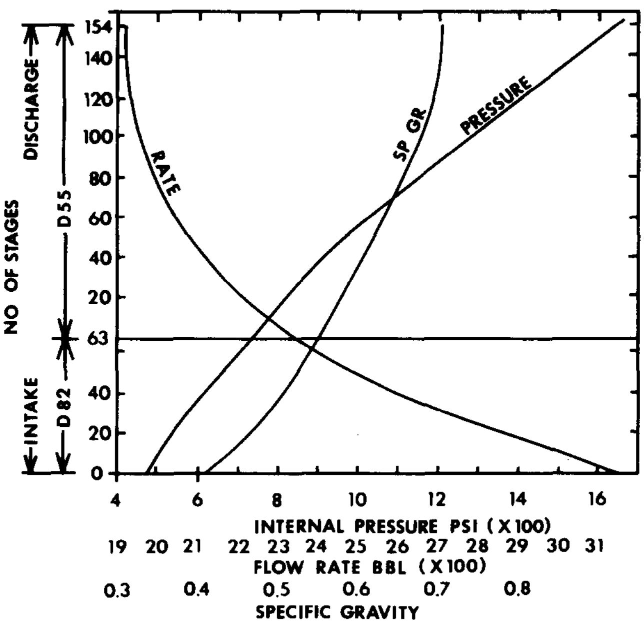

FIG. 7—INTERNAL PUMP GRADIENTS RATE, SPECIFIC GRAVITY AND PRESSURE FOR TAPERED PUMP DESIGN

CONCLUSION

Submergible pumps have been successfully applied in many varied gassy well applications. These designs are never routine and considerable care must be taken to assemble representative production data if optimum designs are to be obtained. With good data, the computerized calculations will allow selection of pumps to successfully operate under a wide variety of conditions.

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3. Orkuyski: Predicting Two-Phase Pressure Drops in Vertical Pipes, *Jour. Petr. Tech.*, June 1967.