

Recommended Practice for Sizing and Selection of Electric Submersible Pump Installations

API RECOMMENDED PRACTICE 11S4
THIRD EDITION, JULY 2002

REAFFIRMED, OCTOBER 2013



AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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FOREWORD

This recommended practice is under the jurisdiction of the American Petroleum Institute (API) Subcommittee on Field Operating Equipment.

This document presents recommended practices for the design (sizing and selection) of electrical submersible pumps. The intent of this document is to provide a “checklist” of items that need to be considered when designing an ESP. It has been written for persons who possess knowledge in basic nodal analysis and petroleum terminology.

This document includes usage of the verbs shall and should, whichever is the more applicable to the function. For the purposes of this document:

Shall: Indicates the recommended practice is considered a minimum requirement that has universal applicability to the specific activity.

Should: Indicates a recommended practice: (1) for which alternative practices may be equally safe and/or effective; or, (2) which may not be practical under some circumstances or applications.

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CONTENTS

	Page
1 SCOPE.....	1
2 REFERENCES	1
3 DEFINITIONS, ABBREVIATIONS AND CONVERSIONS	1
3.1 Nomenclature.....	1
3.2 Conversion Formulas.....	2
4 BASIC DESIGN APPLICATION	2
5 GATHER BASE DATA.....	3
5.1 Estimate ESP Operating Requirements.....	3
6 SELECT PUMP AND INTAKE.....	4
6.1 Match Pump Performance to Well Performance.....	4
6.2 Limitations and Considerations.....	5
6.3 Checklist.....	6
7 SELECT MOTOR.....	6
7.1 Match Motor Performance to Pump/Well Performance.....	7
7.2 Limitations and Considerations.....	7
7.3 Checklist.....	8
8 SELECT SEAL CHAMBER SECTION	8
8.1 Match Seal Chamber to Pump/Motor/Well Performance.....	8
8.2 Limitations/Considerations	8
8.3 Checklist.....	10
9 SELECT CABLE	10
9.1 Match Cable to Pump/Motor/Well Performance	11
9.2 Limitations/Considerations	11
9.3 Checklist.....	12
10 SELECT SWITCHBOARD/VSD AND TRANSFORMER.....	12
10.1 Match Surface Electrical Equipment to Motor/Pump/Well Performance	12
10.2 Limitations/Considerations and Definitions	13
10.3 Optimization and Economics	17
10.4 Checklist.....	18
11 ANCILLARY EQUIPMENT	18
11.1 Check Valve and Bleeder or Drain Valves.....	18
11.2 Backspin Relay	18
11.3 Downhole Monitoring Sensor.....	18
11.4 Centralizers and MotorGuides.....	18
11.5 Anodes	18
11.6 Penetrators	19
11.7 Y-Tools.....	19
11.8 Wellheads.....	19
11.9 Packers	19

	Page
11.10 Cable Bands or Clamps.	19
11.11 Shroud or Motor Jacket.	19
11.12 Cable-deployed Pumping Systems.	19
11.13 Coiled Tubing Deployed Systems	19
12 EXAMPLE PROBLEM	19
APPENDIX A DATA SHEET DEFINITIONS	21
APPENDIX B ESP DESIGN DATA SHEET	25
APPENDIX C COMPARISON OF DOWNHOLE VERSUS SURFACE MOTORS.	27
APPENDIX D VARIABLE SPEED DRIVE AFFINITY LAWS.	29
APPENDIX E FRICTION LOSS IN API TUBING (HAZEN-WILLIAMS CHARTS)	31
 Figures	
1 ESP Design Process	2
2 Electrical Configuration Using a Step-up Transformer	14
3 Electrical Configuration Using a Fixed Speed Controller	14
4 Fixed Frequency and Variable Frequency Pump Performance Curves	15
5 Motor Horsepower Output vs. Frequency	16
6 Motor Horsepower Output and Pump Required BHP vs. Frequency	16
7 Example of a 60Hz—Single Stage Pump Performance Curve	20
E-1 Flow Losses Due to Friction in API Pipe	31
 Tables	
1 Comparison of VSDs vs. Fixed Controllers	17

Recommended Practice for Sizing and Selection of Electric Submersible Pump Installations

1 Scope

Each component of the ESP system (pump, motor, intake, seal or protector, cable, switchboard, etc.) is discussed in some detail as far as what must be considered for the best selection at a desired rate and well conditions. Examples are given to illustrate the basic design procedure and illustrate how PVT correlations, multiphase flow correlations, and inflow performance relationships are used.

Summary designs and computer examples using the detailed design principles are presented which show how design considerations fit together, and how tools such as computer programs allow faster solutions resulting in easier trial and error calculations for optimization of designs and study of existing installations.

Topics such as PVT correlations, multiphase flow correlations, and inflow performance relationships are discussed in the appendices.

2 References

This recommended practice includes by reference, either in total or in part, other standards and recommended practices listed below. The latest edition of these standards and recommended practices should be used unless otherwise noted:

API

RP 11S	<i>Recommended Practice for the Operation, Maintenance and Troubleshooting of Electrical Submersible Pump Installations</i>
RP 11S1	<i>Recommended Practice for Electrical Submersible Pump Tear Down Report</i>
RP 11S2	<i>Recommended Practice for Electric Submersible Pump Testing</i>
RP 11S3	<i>Recommended Practice for Electrical Submersible Pump Installations</i>
RP 11S5	<i>Recommended Practice for Application of Electric Submersible Cable Systems</i>
RP 11S6	<i>Recommended Practice for Testing of Electrical Submersible Pump Cable Systems</i>
RP 11S7	<i>Recommended Practice for Application and Testing of Electric Submersible Pump Seal Chamber Section</i>
RP 11S8	<i>Recommended Practice for Application and Testing of Electric Submersible Pump System Vibrations</i>
RP 500	<i>Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities</i>

RP 5C7

Recommended Practice for Coiled Tubing Operations in Gas and Oil Well Services

3 Definitions, Abbreviations and Conversions

This section provides an alphabetic listing of all the basic terminology and symbols used throughout API RP 11S4. In addition, the formulas to convert between English and metric units are given.

3.1 NOMENCLATURE

B_o	Oil formation volume factor (bbl/STB) [m ³ /m ³]
B_w	Water formation volume factor (bbl/STB) [m ³ /m ³]
f_w	Water cut (fraction range 0 – 1)
H_D	Vertical fluid head measured from the wellhead to the working fluid level (ft) [m]
H_F	Tubing head loss due to friction (ft) [m]
H_T	Head equivalent to wellhead pressure (ft) [m]
J	Productivity index (bbl/day/psi) [m ³ /day/kPa]
KVA	Transformer power rating (kilowatts-volts-ampere)
MD _{pump}	Measured pump intake setting depth (ft) [m]
P_{bhs}	Bottomhole static pressure (psig) [kPa]
P_{wf}	Wellbore flowing pressure (psig) [kPa]
P_{wh}	Wellhead flowing pressure (psig) [kPa]
PIP	Pump intake pressure (psig) [kPa]
q	Desired flow rate of fluid into the wellbore (bbl/day) [m ³ /day]
q_{intake}	flow rate at the pump intake (bbl/day) [m ³ /day]
SCF	Standard cubic feet
SSU	Saybolt Seconds Universal viscosity
STB	Stock tank barrels
TDH	Total dynamic head needed to pump fluid at a certain rate (ft) [m]
VD _{pump}	Vertical pump intake setting depth (ft) [kPa]
VD _{res}	Vertical depth of reservoir (midpoint perforations), (ft) [m]
γ_{API}	Oil gravity term commonly used in the petroleum industry (API)
γ_f	Specific gravity of fluid (measured relative to pure water = 1.000)
γ_o	Specific gravity of oil (measured relative to water = 1.000)
γ_w	Specific gravity of brine (measured relative to pure water = 1.000)

3.2 CONVERSION FORMULAS

Length:

$$\text{cm} = 0.3937 \text{ in.}$$

$$\text{m} = 3.281 \text{ ft}$$

Volume:

$$\text{bbl} = 5.615 \text{ ft}^3$$

$$\text{m}^3 = 6.289 \text{ bbl}$$

Density:

$$\text{kg/m}^3 = 16.01846 \text{ lbm/ft}^3$$

Gas-oil or gas-water ratio:

$$\text{m}^3/\text{m}^3 = (\text{SCF/STB})/5.615$$

Pressure:

$$\text{kPa(g)} = 6.894757 \text{ psi(g)}$$

$$\text{bar(g)} = 14.7 \text{ psi(g)}$$

Temperature:

$$^{\circ}\text{C} = (^{\circ}\text{F} - 32)/1.8$$

4 Basic Design Application

The flow chart illustrated below is an overview of the entire design procedure. The diagram (see Figure 1) illustrates ESP design as a linear process, but it actually may require a few iterations since one particular piece of equipment may impact previously selected equipment. For example, the additional horsepower (HP) required for the seal section may require you to re-evaluate your previous motor selection. Also, you may want to make several design runs in order to optimize your equipment selection and see how sensitive your design is to key input parameters. The detail for each step is described in the noted section.

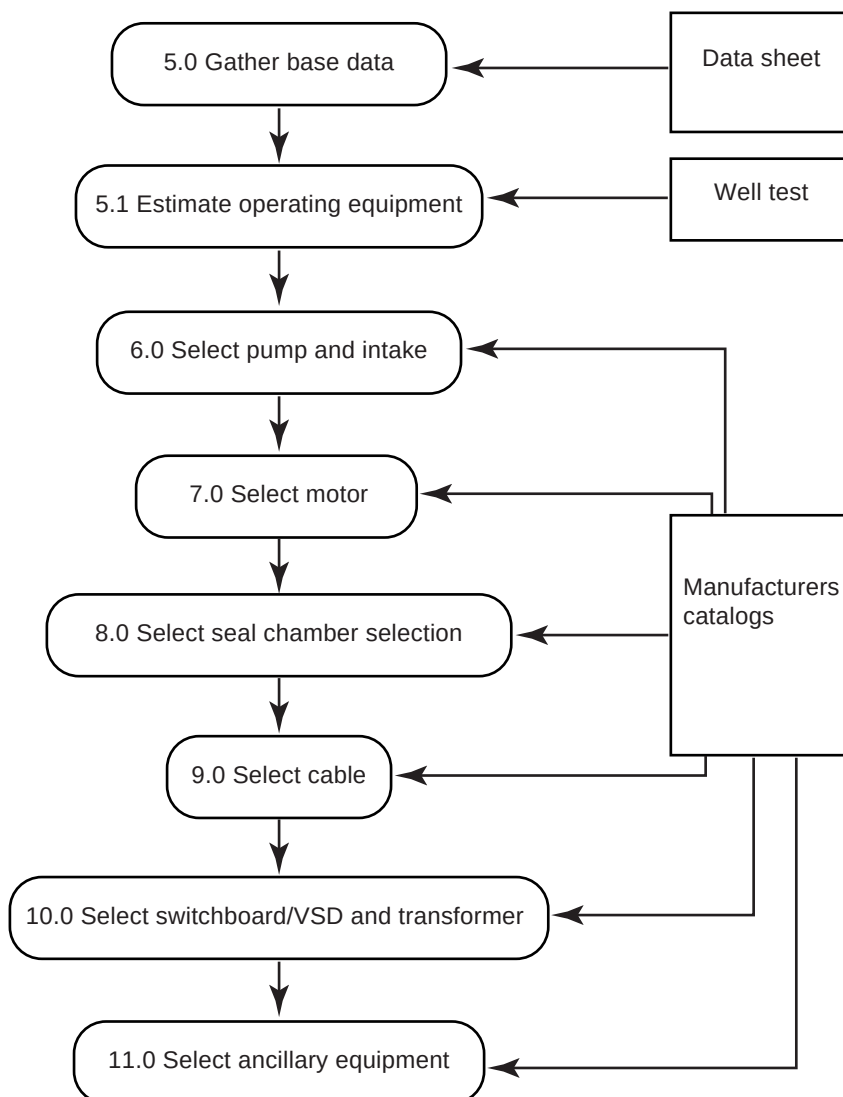


Figure 1—ESP Design Process

5 Gather Base Data

Data is used to describe the environment where the ESP must operate. Care must be taken to quality check data from all available sources. The primary quality limitation of an ESP design is the quality of the data used in the design. The performance characteristics of the pumping system, fluid flow through piping and fluid PVT properties are all reasonably well understood and can be mathematically modeled. If, however, inaccurate data is fed into these mathematical models, an incorrect answer will be produced. Inaccurate data can lead to improper sizing of the pump, motor, or other system components and ultimately lead to premature equipment failure, workovers and deferred production.

The data input sheet shown in the appendix can be used to gather the data required for an ESP installation design. The data elements required for an ESP design can be segregated into six categories:

1. General Information: Identifies the well and who collected the data on what date.
2. Wellbore Geometry: Describes well trajectory and completion equipment details.
3. Surface Information: Describes surface equipment and conditions.
4. Fluid Properties: Describes the fluid produced by the well and chemicals introduced for deposition prevention and corrosion.
5. Inflow Characteristics: Contains data elements that describe the well's productivity. This data is critically important in an ESP design. Care should be taken that this data is as accurate as possible.
6. Design Criteria specifies the desired performance from the ESP installation.

The first five categories define the environment in which the ESP will operate. The sixth category defines the operating parameters desired by the well operator.

The data input sheet contains the minimum data required for an ESP design. Additional information that may be of use to the ESP designer includes wellbore schematics, PVT reports, gas and oil composition reports, and water analysis reports. ESP failure analyses, amp charts, and workover reports on prior ESP installations from the well of interest or offset wells can also provide valuable design clues. If offset well information is included, make certain that the completion reservoir is specified for both the well of interest and the offset wells.

A description of the data elements that comprise each category can be found in the appendix.

5.1 ESTIMATE ESP OPERATING REQUIREMENTS

To properly select the pump, well performance must be estimated. Fundamentally, well performance estimates define what additional energy (i.e., volumetric flow rate and differential pressure or head) must be supplied by the pump to

deliver a desired stock tank flow rate. Ideally, this behavior should be understood or estimated taking into account not only the current well data, but also for forecasted changes in reservoir or system performance over the expected life of the ESP (usually, considering a 3 – 5 year period is sufficient). Specific attention should be paid to expected changes in average reservoir pressure, water cut, producing gas-oil ratio, required wellhead pressure and inflow performance.

Nodal analysis techniques are recommended as the best process for defining well performance and considering sensitivity to changes over time or due to variations in available data. These techniques can be used both numerically and graphically to provide a good understanding of the differential pressure or head that the pump must provide at a broad range of surface flowrates and for a number of varying conditions.

To properly select a pump to produce at a specified stock tank production rate, the corresponding in-situ flow rate must be known and both inlet and required discharge pressures at the stock tank flow rate must be determined. Additionally, the fluid specific gravity must be known. Once the differential pressure requirement is known, this value can be converted to an equivalent head using the composite fluid specific gravity, which, together with the corresponding in-situ flow rate, can be used to select an appropriate pump design and number of stages required to deliver the additional energy required to lift the fluid at the desired stock tank rate. This same approach can be used for single-phase or multi-phase fluid applications. The use of computers to perform complicated inflow performance, fluid properties or tubing pressure traverse calculations is desirable in the latter case.

Single operating point calculations can be effective for defining operating requirements, provided data is good, well behavior is stable over time and the produced fluid is a single phase fluid.

For such applications, it is common to simplify the procedure by combining or summarizing the additional energy that the pump must supply into a single term, Total Dynamic Head (TDH). TDH is a summation of the of the net vertical distance fluid must be lifted from an operating fluid level in the well, the frictional pressure drop in the tubing and the desired wellhead pressure. The TDH and in-situ flow rate can be used directly to select an appropriate pump stage design and number of stages required.

5.1.1 Pump Intake Pressure

Pump intake pressure can be estimated through the use of Productivity Index calculations obtained from well tests or more complex Inflow Performance Relationships. Productivity Index calculations should only be used in single phase fluid applications or in multi-phase fluid applications when the flowing bottomhole pressure is greater than the fluid bubble point pressure. If there is free gas at the pump intake (i.e., pressure is below bubble point), emulsions present or the

fluid is highly viscous (less than 40 SSU), use applicable computer software as hand calculations are not recommended.

Pump inlet pressure is dependent on pump setting depth. Pump inlet pressure is simply the flowing bottomhole pressure adjusted for change in pressure due to the static gradient of the fluid (due to the vertical distance the pump inlet is placed above the reservoir or pressure datum location) and frictional pressure drop in the casing between the perforations and pump inlet (which is generally very small and is normally ignored).

It is quite common in ESP applications to make pump setting depth somewhat arbitrary, providing a safe amount of submergence is available and depending on the well deviation. In other cases, a safe desired pump inlet pressure is specified and the pump depth is determined which will provide this inlet pressure at the operating stock tank flow rate.

In most single-phase fluid applications, 100 psi inlet pressure is sufficient. For unusual flow characteristics (such as high volume), pump Net Positive Suction Head requirements should be checked.

In gassy applications, it is common to set the pump inlet as deep as possible to keep pump inlet pressure as high as possible, so less gas evolves from the fluid before it reaches the pump inlet.

A simplified procedure for calculating pump inlet pressure is as follows:

Calculate Well Fluid Composite Gravity

$$[f_w \times \gamma_w] + [(1 - f_w) \times \gamma_o] = \gamma_f$$

Calculate Well Fluid Gradient

$$[\text{Fluid gradient}] = [\text{Water gradient} \times \gamma_f]$$

where

$$[\text{Water gradient}] = 0.433 \text{ psi/ft or } 9.8 \text{ kPa/m}$$

Calculate Well Flowing Pressure at Desired Flow Rate (P_{wf})

$$P_{wf} = P_{bhs} - [q/J]$$

Calculate Pump Intake Pressure (PIP)

$$PIP = P_{wf} - \{[VD_{res} - VD_{pump}] \times [\text{Fluid gradient}]\}$$

Calculate Intake volume at pump (q_{intake})

$$q_{intake} = [\text{Surface volume water} \times B_w \text{ at pump depth}] + [\text{Surface volume oil} \times B_o \text{ at pump depth}]$$

Note: The total intake volume when below the bubble point must include the free gas volume.

5.1.2 Total Dynamic Head

For applications pumping a **single phase fluid**, the term Total Dynamic Head can be used to summarize the differential pressure or head the pump must supply to lift fluid at a desired flow rate from an operating fluid level in the well to the surface.

Calculate Net Vertical Dynamic Lift (H_D)

$$H_D = VD_{pump} - [\text{PIP/Fluid Gradient}]$$

Determine Friction Loss (H_F)—refer to Hazen-Williams chart in Appendix E.

$$H_F = MD_{pump}/1000 \times [\text{Friction loss for given tubing size and production rate}]$$

Calculate Wellhead Tubing Pressure Head (H_T)

$$H_T = \{P_{wh} \times [2.31 \text{ ft/psi}]\} / \gamma_f$$

Calculate Total Dynamic Head (TDH)

$$TDH = H_D + H_F + H_T$$

6 Select Pump and Intake (see API RP 11S2)

A pump with capacity matching desired well production should be selected based on an expectation of well performance based on pump performance data from a manufacturer's catalog. Additional operating constraints are taken into account during this selection. These constraints include casing size, housing burst pressure limit, shaft strength, corrosive, abrasive or gassy environments.

6.1 MATCH PUMP PERFORMANCE TO WELL PERFORMANCE

Submersible multistage centrifugal pumps consist of rotating impellers that are affixed to a shaft and stationary diffusers that are mechanically held within an outer housing. A matched set consisting of one impeller and one diffuser is commonly referred to as one stage. The pump functions by imparting kinetic energy to fluid as an impeller rotates. The stationary diffuser then rectifies the fluid back toward the shaft and inlet to the next impeller, converting the kinetic energy into potential energy in the form of increased head (or pressure). This process is continued from stage to stage. The amount of head increase due to an individual stage is independent of fluid density, although the pressure increase is proportional to density or specific gravity.

The geometry of a pump design (e.g., number of vanes, vane angle, vane height, diameter, vane length, etc.) controls

the performance of the pump. This performance is normally summarized in a pump performance curve (on either a single stage or multistage basis, commonly 100 stages or a specific number corresponding to the number of stages in a specific pump) that relates head (differential pressure), power required and mechanical efficiency to volumetric flow rate. These curves are often drawn showing flow rate to be the independent variable with head, power and efficiency being the dependent variable. This is actually only one way of looking at pump performance. For purposes of sizing, it is often useful to understand that in fact the relationship works in the other direction as well. The flow that a specific pump with a specific number of stages can provide depends on the differential pressure imposed on the pump.

The task in pump selection is to select the appropriate pump stage design for the desired pump flow rate and then select the appropriate number of stages to deliver the desired flow rate given the necessary head or differential pressure required to cause the well to flow at the desired flow rate.

Care should be taken to insure that in-situ pump flow rates and not stock tank rates are used to properly select stage type and number of stages.

A simple process for pump selection consists of the following steps:

Determine Stage Type

Depending on casing size and desired flow rate, there may be several possible pump stage types available for a given application. The pump stage type should normally be selected primarily on the basis of which pump will be most efficient at the desired operating flow rate. As a rule, a pump should be selected such that the desired operating flow rate is as near as possible to the best efficiency point and, as a minimum, within the recommended operating range stipulated by the manufacturer. Although many pumps can be operated outside this range, the pump performance is best within this range and it is within this range that pumps are commonly tested by those adhering to API RP11S2 *Recommended Practices for Submersible Pump Testing*.

Determine Number of Stages Required

Given a desired flow rate, Total Dynamic Head (TDH) required and pump stage type, read the head per stage corresponding to the desired pump flow rate. The number of stages required to achieve the desired flow rate will be the TDH divided by the head per stage at the desired pump flow rate.

$$\text{Number of stages} = \text{TDH} / [\text{Head per stage from pump curve at pump flow rate}]$$

Pumps are normally available with a discrete number of stages in predetermined pump section lengths (often referred to as housings). Multiple sections may be assembled together to obtain the total number of stages required. In some cases,

the number of stages available may not exactly match that required. In most cases, this results in a very small error.

There are two configurations of pumps. In a floating stage design (most common), the impellers float axially on the shaft and the thrust of the individual impeller stage is absorbed on specially designed pads found on the diffuser. The fixed impeller or compression pump design has the impellers locked to the pump shaft in the axial direction and no thrust is absorbed by the impeller rubbing on the diffuser. In the compression pump, the thrust is transferred to the thrust bearing in the seal chamber. Please consult with your pump manufacturer to discuss which design is better for your application.

Determine Power Required by Pump

Read the horsepower per stage required by the pump from the curve at the desired pump flow rate. Calculate the total motor horsepower required to drive the pump by multiplying horsepower per stage by the number of stages and composite fluid specific gravity.

$$[\text{HP required}] = [\text{HP per stage}] \times [\text{Number of stages}] \times \gamma_f$$

This information should be used in selecting a proper motor HP size.

6.2 LIMITATIONS AND CONSIDERATIONS

Besides hydraulic performance, several other physical limitations must be considered, even in simple applications.

6.2.1 Shaft Strength

The amount of horsepower that the pump shaft can transmit (torque at a given speed) should be checked to insure it is within acceptable limits stated in the manufacturer's catalog. Exceeding this limitation can result in premature failure.

6.2.2 Housing Strength

The pump differential pressure under operating and shut-in conditions should be checked to insure it does not exceed burst pressure limitations. Worst case pump head can be determined by obtaining shut-in head per stage from the zero flow rate point on the pump head capacity curve and multiplying it by the number of stages. In most cases, different designs are available for extremely high differential pressures. Exceeding this limit can result in premature failure. Please consult with your ESP manufacturer for equipment ratings.

$$[\text{Shut-in pump head}] = [\text{zero flow head per stage}] \times [\text{Number of stages}]$$

$$[\text{Differential pressure}] = [\text{Shut-in pump head}] \times [0.433 \times \gamma_f]$$



6.2.3 Pump Thrust

The pump shaft thrust should be calculated to use in seal chamber section thrust bearing design selection. While the limitation to be checked is a consideration of the seal chamber section, the source of the thrust is the pump. The magnitude of thrust depends on the number of stages employed and the mechanical configuration of the pumps being used. The most common form of pump is commonly referred to as a floating impeller pump, in which the pump impellers are free to travel axially somewhat. In being free to travel, the individual diffusers carry the thrust generated directly by each impeller. The differential pressure developed by the pump acting on the cross sectional area of the pump shaft causes a separate thrust load that must be accommodated for by the seal chamber section thrust bearing. Again, this load should be calculated for worst case, shut-in conditions.

$$[\text{Floater pump thrust}] = [\text{Pump differential pressure}] \times [\text{Shaft area from manufacturers catalog}]$$

Thrust calculations for fixed or compression type pumps should be based on data provided by pump manufacturers and worst case operation (e.g., shut-in).

6.2.4 Variable Speed Design

While variable speed drives provide additional flexibility and adjustability to ESP installations, they complicate pump selection. Variable speed drives capitalize on the behavior of centrifugal pumps at different speeds (where affinity law equations be located). As a general rule, the design should begin at the highest frequency to be sure the equipment will be sufficient to handle situations such as lifting kill fluid upon start-up. However, the best efficiency rate should be targeted for the frequency at which the longest running time is expected in the application. While this can be calculated by hand, the use of computer software is recommended to handle the conversion of pump performance data at variable speeds.

6.2.5 Gassy Wells/High Vapor-liquid Ratios

As explained above, hand calculations are inadequate for applications with more than a few percent of vapor in the fluid flow stream at the inlet of the pump. In these applications, computer software should be used to handle the more complex inflow and multiphase flow calculations and multiphase pump performance calculations based on PVT data and correlations. Specific attention should be paid to avoid sizing pumps for normal operating conditions that are incapable of lifting heavy kill fluids or completion fluids during startup.

There are design options for handling the gas, either through the pump or separating it out of the flow stream prior to entering the pump. There are special pumps made to handle a high percentage of free gas. Please consult with your

manufacturer to find out the free gas limitations on their equipment. Another design is the tapered pump, which uses several different volumetric stages (large flow capability on bottom, smaller flow capacity on top). As the fluid is compressible, the volume becomes smaller as it travels through the pump.

Gas separators are also available. Consult with your manufacturer to determine which type of separator is best for your application. The user will also need to determine if the separator requires additional horsepower to function. This value will be needed to properly size the motor.

6.2.6 Abrasives

Abrasion resistant pump trim and features should be selected for applications in which abrasive solids, such as sand (grain size and shape is essential data), scale, etc., are expected. While there are many different designs available, manufacturers are generally able to help specify an adequate level of bearing and material options to mitigate abrasive wear concerns. The type and volume of sand dictates the materials needed and its placement inside the pump.

6.3 CHECKLIST

- Select the appropriate pump stage design for the desired pump flow rate.
- Determine number of stages required.
- Determine power required by pump (horsepower).
- Ensure the pump shaft and housing strengths are within acceptable limits.
- Ensure the proper metallurgy for produced well fluid is selected.

7 Select Motor

A motor must deliver the horsepower required to run the pump, seal chamber section, and gas and water separator, if required. Important considerations include temperature limitation, casing size, length and size of cable, motor terminal voltage, motor current and also the well operating conditions.

The horsepower requirements and the well conditions should be studied against the catalog listings to determine which catalog horsepower will satisfy his requirements, i.e., should he use a smaller catalog horsepower to meet his requirements or a de-rated larger horsepower or stick with the closest catalog horsepower. All possibilities will have different cost associations.

The motor nameplate voltage should be selected in conjunction with the cable selection, as the different motor voltage ratings will require different currents which will impact on the running costs as far as cable losses are concerned. A realistic of run time estimate should be made so that running costs and initial costs can be added together to give a cost comparison for each case considered.

