ESP DESIGN AND ANALYSIS OF EXISTING INSTALLATIONS

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ABSTRACT

A design procedure is detailed which uses motor performance and electrical submersible pump stage performance corrected to actual pumping speeds with IPR performance. The program then shows what any selected design will produce under various conditions including HZ and surface pressure. The calculations routine is "Nodal®" (TM of Macco Schlumberger) in the respect that it will plot expected performance of a given design at either the perforations or at the pump intake. At the perforations, an IPR curve can be checked or generated by using the program output. Pump intake pressure readings can be checked against the program output if the calculated output plot is selected at the pump intake near a downhole pressure instrument. The design is made at one point and operation at a broad band of of off-design conditions is made using graphical output. Examples are presented to demonstrate some design considerations that should be examined when considering an application of ESPs in a new area.

INTRODUCTION

Several recent publications have described ESP (Electrical Submersible Pumps) design and analysis techniques for computer analysis (Refs. 1, 2, 3, 4, 6, 7, 8). One of the newer techniques is to include motor performance calculations into models so that the actual motor speed is calculated when the pump load is determined. This also allows calculation of the motor amp demand, the cable electrical losses, the motor efficiency and the cost of operation at any set of conditions in the range of the pump and motor.

The results presented in this paper were calculated using an ESP computer model which uses motor performance curves to calculate the actual rotational motor speed as the pump load is calculated. Additionally there has been some discussion in the literature about models which also include some calculated economics which are developed making use of user inputs of initial cost and expected life of the equipment (Refs. 4, 5). The material presented here does not contain any economic calculations but instead focuses on the type of graphical presentation, some discussion of the sequence of calculations necessary to generate results, and some typical calculations that might be made to study installations of ESPs designed for a new field. Particular emphasis on variable speed drives (VSDs) is made to show how they may be used to expand production possibilities where rates are expected to vary from well to well and expected to vary with time.

PRODUCTION STRUCTURE

The program used to generate results for this presentation is probably not too dissimilar than some other programs discussed in the literature although it does contain some specific features which may be unique.

The stage performance is calculated from manufacturers' curve fits. The motor performance is also from manufacturers' supplied curves. The reservoir performance is found from typical Inflow Performance Relationships(IPR curves) which are developed from user supplied well tests. The performance of the pump system at various HZ (frequency supplied from variable speed drives) is calculated using the so call pump "affinity laws" which are published in a number of references.

The output is presented by the program used here by intersecting a reservoir IPR curve at the sandface with a tubing-pump outflow curve as shown in Figure 1. A particular design is made at one point by selecting enough stages to build pressure from the intake pressure (determined from IPR and any flow path below the pump) to the discharge pressure required. The discharge pressure is determined from use of a multiphase flow program. Then performance at off design conditions is determined from the inflow-outflow curve intersections. The user can also select presentation of the output to be at the pump intake pressure instead of the sandface. The program then subtracts the flow path pressure drop below the pump from the IPR curve at the sandface. Then the inflow curve is intersected with a tubing-pump curve which is constructed to the pump intake pressure and not to the sandface pressure.

The development of the IPR curve is common practice and is not discussed here. The development of pump-tubing outflow curve is straight forward as long as gas separation is not considered. The development of the pump-tubing outflow curve is shown in Figure 2. First a stock tank rate of fluid production is chosen. Then the program proceeds from the wellhead pressure to calculate the discharge pressure. Then pump curves are entered to drop from the pump discharge pressure to the pump intake pressure. Then if a flow path exists below the pump, the program calculates the pressure increase to the sandface pressure. When this is done for a succession of rates, a so-called tubing-pump performance curve is generated which can be intersected with an IPR curve to predict a performance rate and intake pressure. If gas separation is a function of the intake pressure (which it is) then the calculation of the tubing-pump outflow curve becomes iterative. This is because the calculation of the discharge pressure and the pump performance require a value of the GLR. But the GLR is a function of the calculated pump intake pressure. So the GLR above the pump intake must be adjusted until the gas after separation through the pump and the tubing is in agreement with the separation calculations at the pump intake pressure.

Next, to put manufacturer's recommended limits or operational limits on tubing-performance curves requires even more calculations (as shown in Figure 1). The definition of these limits must first be described. The "operational limits" or "recommended limits" for a series of stages instead of just one stage would be the largest in-situ flow rate recommended for the stage in the design which is constructed for the largest flow rate and the smallest recommended rate for the stage designed for the smallest in-situ rate in the design. Because of fluid and gas shrinkage, the minimum volume would occur in the last stage at the discharge pressure and the maximum would occur at the first stage at the inlet pressure. However, if the design is "tapered," then checks for maximum and minimum volumes must be made at points other than discharge and intake pressures.

For the output presented here, the produced or stock tank barrels of fluid corresponding to the in-situ limits are reported as the limiting flow rates.

If operational limits are to be placed on an outflow curve, as shown in Figure 1, then the program developer has to examine some choices. One method is to just input a grid of rates and observe when the maximum and minimum flow volumes are reached at the respective intake and discharge pressures. Then the stock tank rates which causes the down hole in-situ maximum and minimum volumes in the pump stages can be recorded and plotted on an inflow-outflow plot. Another method would be to assume a stock tank rate and calculate the in-situ volumes that occur in the pump at the intake and discharge pressures. Then by iteration, the two stock tank rates are found which cause the occurrence of the minimum and maximum rates in the pump. Many other design and analysis details for construction of a computer program are to found in the literature (Refs. 1-8).

DESIGN STUDY

The discussion in this section is used to illustrate, some of the calculations that should be made before developing a new field with ESPs. For purposes of illustration , an offshore development is assumed. Further, it is assumed that well tests have indicated a range of possible IPR curves . Also assume that due to possible water production problems and sandy conditions, the initial target production values could be adjusted as production experience is gained. Further assume that to best cover the range of possibilities, VSDs will be applied. Calculations for an onshore discovery would still require similar analysis although planning requirements might not be as stringent. Also more variation in equipment for each well could be more easily planned for and provided for most onshore installations.

Assume the below data for well conditions for the following example calculations:

DESIGN CONDITIONS

Target rate = 5000 blpd	IPR data:
GLR = 100 scf/bbl	
WOR = 1	SIBHP = 1600 psi
API = 18	Test rate = 2000 blpd
Gas gravity = .79	Test Bhp = 1266 psi
Water gravity = 1.03	
BHT = 140 F	surface tubing pressure = 245 psi

well dimensions to pump: sand face just below pump:

tubing i.d.	measured depth	angle
3.96	0	0
3.96	1000	31
3.96	2500	63

GAS CALCULATIONS

Since some gas can be present, preliminary calculations are made to determine if a rotary gas separator is required. Figure 3 shows what a design made at 60 HZ for 5000 blpd would do with no gas separation. A sample value of 15 pct separation due to the casing-tubing annulus is input for this case. In order to design with a stage that will pump the in-situ volumes, a stage with manufacturers' recommended limits of 3650 to 8100 blpd was used. The in-situ volume was calculated to be over 6600 blpd at the 60 HZ design point. Note that the design rate of 5000 blpd is reached where the 60 HZ outflow curve intersects the IPR curve. All of the other curves are for this same design operating at off-design conditions.

This design required 78 stages to generate the required pressure. Additional calculations and decisions led to the use a 300 hp motor which is used for all remaining example calculations. This large motor is input so the well could be pumped up to the limits of the VSD if desired. If only 60 HZ operation is desired, it could be smaller. Additional calculations might be made to be sure that the motor that uses the least energy might be selected , especially if the motor is to be used onshore where energy consumption is a strong consideration. Offshore, equipment availability, and predicted life are bigger concerns than efficiency although not necessarily contradictory.

The design made for Figure 3 is calculated to perform well at 30, 45 , and 60 HZ according to the criterion presented in Ref. 10 (666 x gas volume)/(intake press x liquid volume) < 1) which is a correlation of the data collected in Ref. 9 . However, at 75 and 90 HZ, the gas volume is calculated to be so large as to be expected to severely reduce stage performance. Therefore operation at these higher values of HZ is not possible because of gas problems.

Figure 4 is a summary graph obtained from the intersections of the inflow curve and the outflow curves at various HZ shown in Figure 3. Plotted in Figure 4 are the motor amps/full load amps, production in blpd, and the pump intake pressure (psi). Note that the motor is reaching 90 percent of the full load value of amps around 75 HZ which is about where gas interference is predicted. This summary curve can be produced for any of the detailed inflow-outflow plots but is shown here only for this example.

Next, Figure 5 shows a design and its performance using a rotary gas separator performing according to a published manufacturers' curve (Ref. 11). For comparison to Figure 3, the same stage is selected although with less gas, a smaller capacity stage could be chosen. In this case the maximum in-situ volume was calculated to be about 5200 blpd at the 60 HZ design point. Eighty-one stages are required. This particular design is calculated to have no problems handling gas for the 30, 45, 60, and 75 HZ tubing-pump operational lines. The well pumps off at 90 HZ. The 75 HZ operation is marginal because of the low intake pressure. However, at 60 HZ, for example, the design with no separator loads the motor less than the design with a gas separator. Because of possible wide field variations the separator is chosen for remaining cases although not a lot of difference is shown between Figures 3 and 5 for this amount of gas. It might be mentioned in in passing here, that some companies are now trying tandem gas gas separators. Tandem protectors or motor seal sections have been applied in the past as well.

STAGE PERFORMANCE

Next, three different types of stages, all of which work at the design point, are considered. Figures 5, 6, and 7 show designs at 5000 blpd and their performance at various HZ, with each Figure showing results using a different stage making up the design. The following data summarizes some results from the graphs under discussion.

Figure no.	Stage Performance No. of Stages Req'd	Max-Min Limits, blpd
5	81	3650 - 8100
6	104	2500 - 5600
7	96	4400 - 10300

The main reason for selecting the design in Figure 6 is that there is more down side performance if the expected IPR should be found to be below the curve plotted in the Figures or the IPR starts to drop with time.

SURFACE PRESSURE EFFECTS

Since surface facility performance could be still under design while pumps systems are being selected, it is desirable to predict the possible effects of surface tubing pressure on production. At 60 HZ, using the stages illustrated in Fig. 5., a study of surface pressure effects is shown in Figure 8. A possible spread of about 4800-5100 blpd is predicted as surface pressure is varied from 150 to about 350 psi. The production sensitivity to well head pressure could generate economics which could drive the design of surface facilities if this data can be accurately predicted.

PERFORMANCE OF EXISTING INSTALLATION: EFFECTS OF EMULSIONS

Suppose that the design illustrated in Figure 6 is applied in field operations. Further suppose that although designed to produce 5000 b/d at 60 HZ, the applied design produces only about 4600 blpd. Assume that the IPR is retested and that the pump was tested prior to installation etc..

One possibility is that the oil and water being produced form an emulsion when the unit is applied in field conditions. The design illustrated in Figure 6, was designed with the viscosities of oil and water weighted through the pump with a viscosity correction factor found using curves describing a "Loose Emulsion" using data from the API RP11 U (Ref. 8). However, in order to match assumed field performance, the oil and water have to be input as a "Medium" emulsion to obtain a viscosity correction factor which will make the program predictions match the measured field data. This is one method of matching actual performance with a computer model, when emulsions are suspected to be causing a production decrease. The calculations using a "Medium" emulsion fluid are plotted in Figure 9 showing a "match" with "actual" conditions of 4600 b/d at 60 HZ.

However, it must be mentioned that ESP's many times do not cause oil and water to act as an emulsion. This is probably because the flow through ESP's is fairly streamlined and is not a violent mixer as is sometimes thought. Matches to field test data using an ESP may also be used to verify that the fluids do not emulsify through the pump.

SUMMARY

Several types of calculations are illustrated which should be considered when applying ESP's to a new field. The applications of VSD's is illustrated for these examples. The results are illustrated using inflow-outflow type plots with the manufacturers' recommended maximum and minimum limits shown on the tubing-pump outflow plots. These types of presentations are especially useful when one wishes to lay in additional IPR plots, or just consider what type of production spread can be covered by the ESP design with VSDs when IPRs may be expected to vary.

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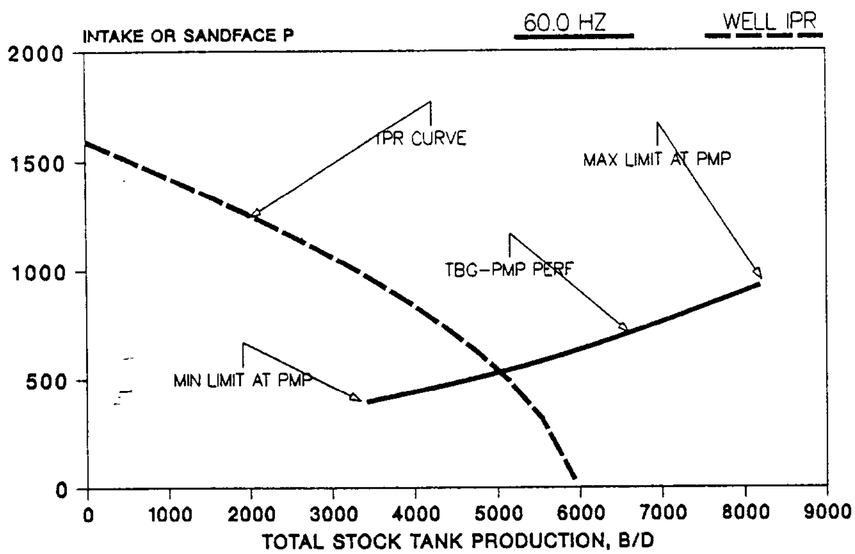

Figure 1 - Example IPR inflow: intersecting tubing–ESP outflow curve

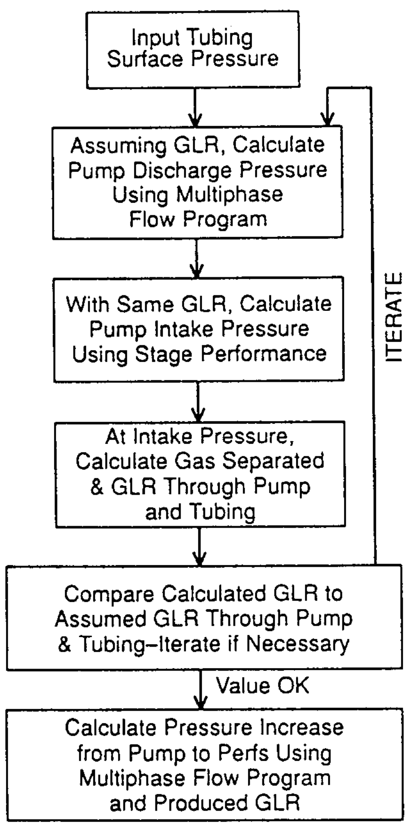

Figure 2 - Development of tubing–pump outflow curve using gas separator performance

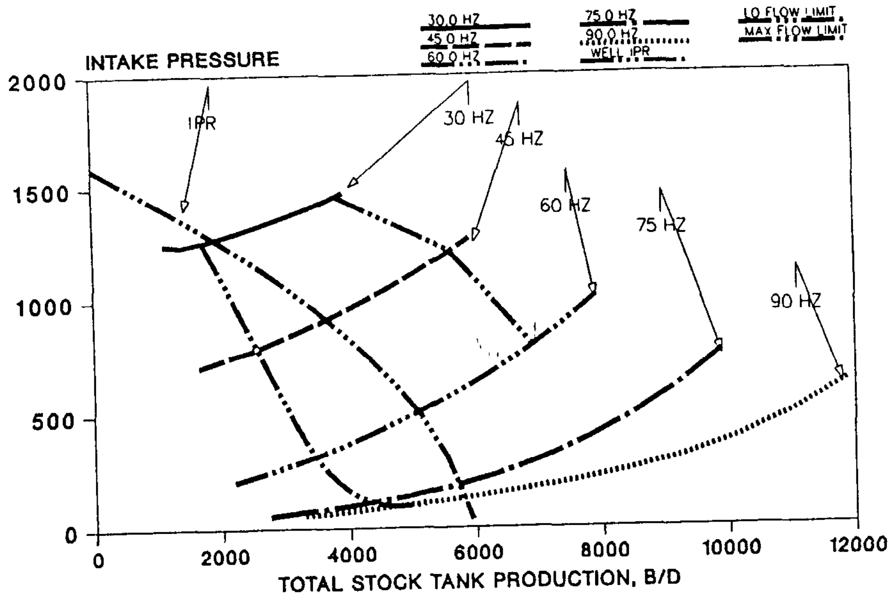

Figure 3 - No gas separator: stage limits, min.=3650, max. = 8100 B/D

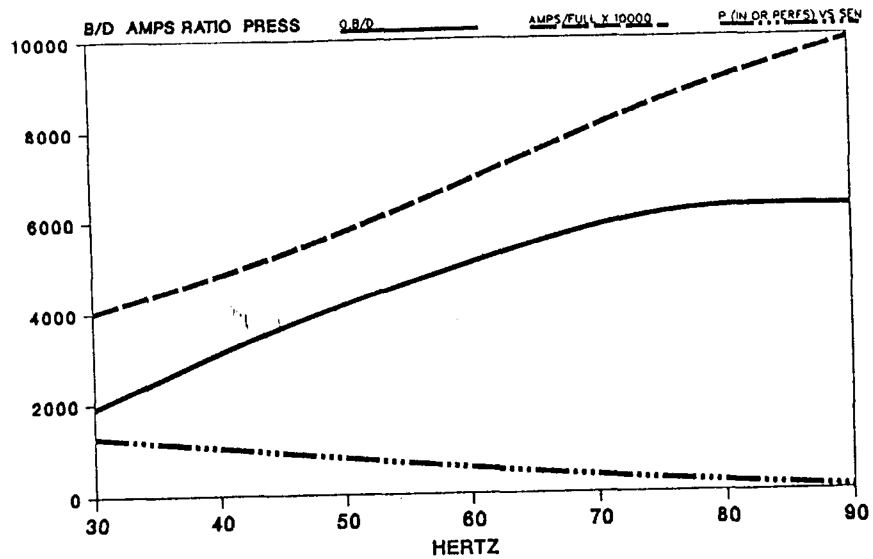

Figure 4 - No gas separator: flow, amps, and P vs. hertz

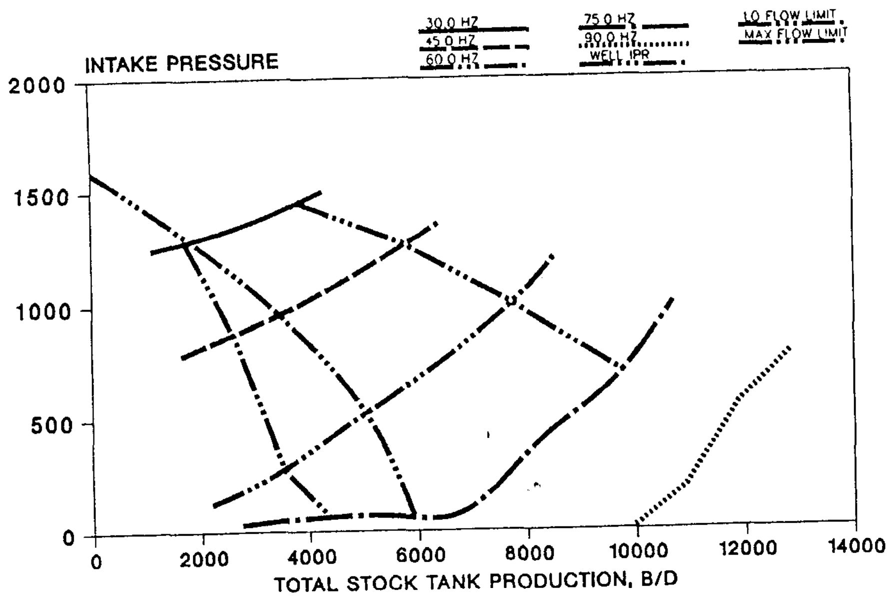

Figure 5 - Gassy well with separator: stage limits, min.=3650, max.=8100 B/D

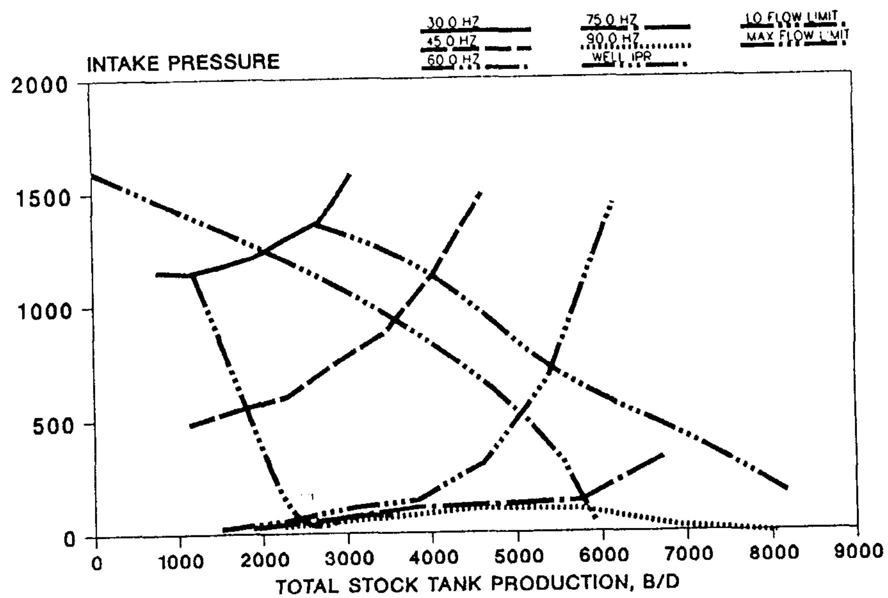

Figure 6 - Stage performance: stage limits, min.=2500, max.=5600 B/D

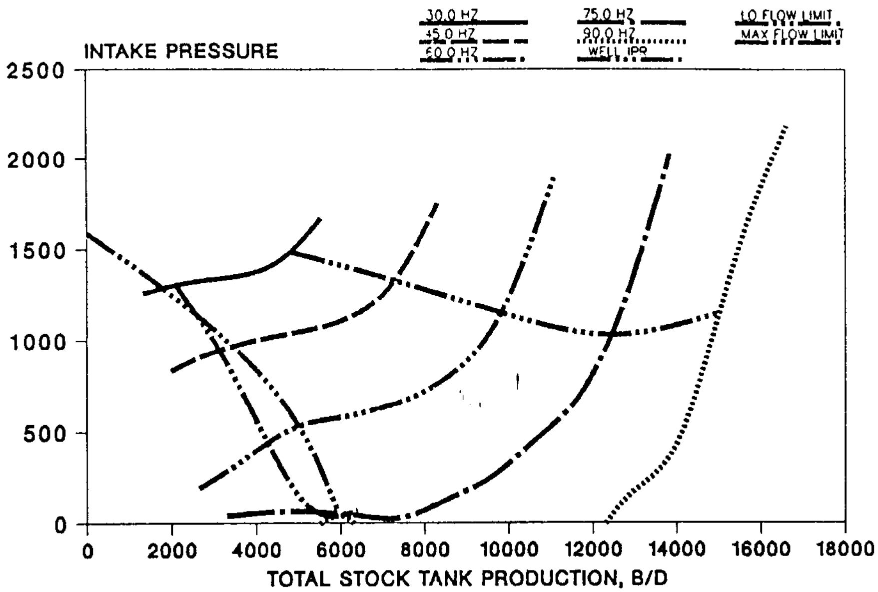

Figure 7 - Stage performance: stage limits, min.=4400, max.=10300 B/D

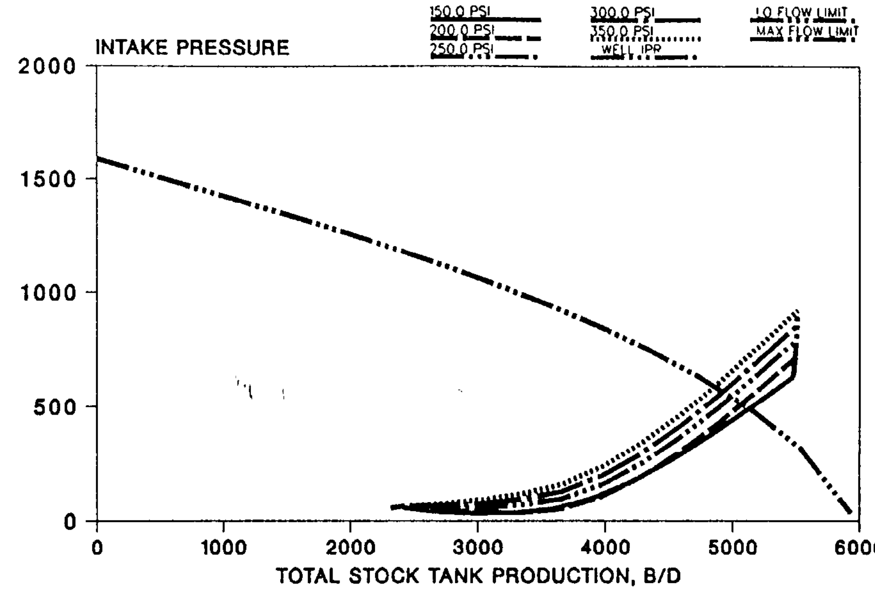

Figure 8 - Effects of wellhead pressure

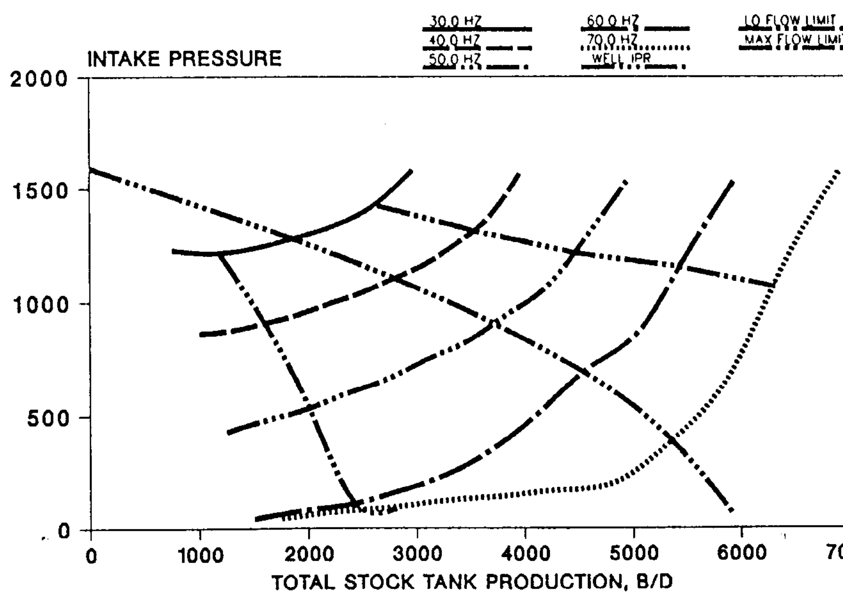

Figure 9 - Matching performance of well with emulsion