WELL TESTING WITH THE VARIABLE SPEED PUMP

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ABSTRACT

The process of selecting or correctly sizing any artificial lift system involves many factors and relies on accurate and dependable data. This paper presents a cost effective method to determine the productivity of a well using electric submersible pumping equipment. A variable speed test is performed to provide the operator with sufficient information to properly design a permanent artificial lift system.

The uncertainty of a well's response at higher volumes or lack of substantial data, prove the need for this test system. The application of the test unit and services provided will be discussed, as well as field results from actual tests.

INTRODUCTION

The variable speed submersible pump has been used in the oil field for over a decade. The electric submersible pump (ESP) when run at constant speed has a production characteristic such as that seen in Figure 1. It can be seen that as the production rate of the pump increases the head, or lift, that the pump can generate decreases. This implies that the producing rate and associated lift required by an oil well must be established before a submersible pump can be properly sized. Additionally, if the performance of the well changes with time, the submersible pump first placed in the well would not necessarily remain the correct one to keep the well's production optimized.

To increase the flexibility of the submersible pump, variable speed (frequency) controllers have been used to give the submersible pump a wider operational range. Use of speed control allows the pump to generate a family of head rate curves as seen in Figure 2. With this type of pumping system well productivity can be tracked with pump production capacity.

The use of the variable speed submersible pumping system in fixed applications is described in detail by Divine, Ref. 1. While the variable speed system has many positive characteristics it also increases the initial capital cost of the production system by as much as 100 percent. Additionally, the controllers are very sophisticated and can require additional and specialized maintenance. These factors have limited the use of the variable speed submersible pump in many fixed applications.

The flexibility of these systems in testing applications was recognized early on. Kelly, Ref. 2, discussed the use of variable speed pumps in testing in the late seventies. Kelly described the use of the variable speed controller to resize submersible pumped wells. The drawback to this testing technique is that the submersible motor in an existing application is usually loaded when the test begins. This means that to obtain a higher rate from the well the motor must be overloaded. Often only minimal information can be obtained for resizing. Of course if there were a beam unit on the well then a submersible would have to be installed on a rental or lease basis to test the well.

The best way to accomplish this is with a testing system designed to cover a wide range of flow rates at the desired lift. As an example, a company operating a waterflood where the average reservoir depth is 5,000 feet might want a submersible testing system that would allow a production rate from 700 to 1,800 BPD. This equipment would be a considerable capital expense and might not be needed but for a few tests a year in that particular waterflood.

Historically the alternative to buying the equipment was to lease it from the pump manufacturers. This also was very expensive in that the manufacturers required not only the monthly lease payment, but also required payment for repair costs at the end of the test if the test equipment was returned or traded for the correct size pump. Of course, if the leased equipment happened to be the correct size, then the purchase of the leased test equipment would be cost effective. The total cost of leasing for a test could often run as high as if the equipment were purchased. This limited the application of the variable speed pump in well testing applications.

This paper describes commercially available test systems which utilize used, tested equipment in order to make the service financially attractive.

EQUIPMENT DESCRIPTION AND TESTING PROCEDURES

The well testing package comes complete with the following:

1. A variable speed controller and associated step up transformer

2. Downhole power cable

3. Wellhead

4. Submersible pump, motor, protector, and optional pressure sensor

5. Daily fluid shots

The operator of the well needs only to supply the electrical power, the tubing string, the installation and removal costs and the well testing facilities for determining oil, water and gas rates. The oil company is not responsible for any repairs on the equipment. Instead of repairing the equipment after every test, the pumps, motors, protectors, and pressure sensors are cleaned and tested as described by Divine and Johnson, Ref. 3 and 4. This routine maintenance procedure increases the equipment life while substantially reducing the cost of running the equipment.

A typical test procedure would begin by producing the well at a slightly lower fluid level and slightly higher rate than the well was producing at before the installation of the test system. This might require running the pump at 45 hertz (3/4 speed) as depicted in Figure 3. After the well is stabilized at 600 BFPD and at a producing fluid level indicated at A, the pump might then be sped up to 50 hertz to obtain a lower fluid level at higher production rate. This is indicated as 800 BFPD at a producing fluid level indicated at B in Figure 3.

It is often important not to try to pump the well off from the very beginning. In the case of older wells, the casing may develop a leak. By slowly reducing the fluid level, this leak may be detected early enough to be repaired before a possible casing collapse with associated loss of equipment and possible loss of the well.

By slowly drawing the well down and stabilizing at different flow rates, the oil cuts at these different rates can be monitored. It is well documented that oil cuts are not necessarily constant for all drawdowns and rates, Ref. 5. This monitoring of the oil cuts versus rates allows the most efficient and economical submersible system to be installed.

Continuing with the procedure, the next rate would be selected and again the rate and oil cut monitored. Depending on the installation, a technician would come by the location to shoot fluid levels, check the bottom hole pressure reading and determine the rate and oil cut. If a speed change in the pump was necessary to maintain the well's test rate or bottom hole pressure then the correction could be made at that time.

WELL TEST CASE STUDIES

Case Study No. 1

Case 1 had been recently drilled and was producing with a high fluid level. The well was producing with a beam unit which was operating at capacity. The following information was available:

Casing Size = 5 1/2", 17#

Tubing Size = 2 7/8" EUE 8RD

Perforations Depth = 10,400'

Static BHP = 2650 PSI

Production Rate = 356 BFPD

Flowing BHP = 2560 PSI

Oil Cut = 13%

Bubble Point = 3800 PSI

GOR = 900 SCF/BBL

Producing Annular Fluid Gradient = .38 PSI/FT

Based on the two data points and applying Vogel's Inflow Performance Relationship, Ref. 6, the well would have a Qmax of 5913 BPD. See Figure 4, Curve 1. The operator knew that this was very unlikely based on the productivity of adjoining wells in the same reservoir. As a matter of fact the operator felt it would be unusual for the well to make even 1000 BFPD if the fluid level was drawn down to the perforations. A variable speed test system was selected that would have a range that is shown in Figure 4. The enclosed area represents all the operational points available for the variable speed pump. The line from A to B represents the minimum range of a D1350 impeller from 38 hertz to about 69 hertz. The line from B to C would be the maximum lift when the fluid level is at the perforations. The line from C to D is the 70 hertz curve for the D1350 and is where a 150 h.p. motor reaches full load at 70 hertz. The line from D to E is the maximum range of a D1350 impeller from 70 hertz to about 61 hertz. Finally the line from E to A is the static bottom hole pressure (BHP) and operating on or above this line would yield no production. This system consisted of the following:

1. 324 stage, D1350 pump
2. Rotary gas separator
3. Set of tandem type 66 protectors
4. Tandem 150 h.p. 456 series motor
5. Pressure sensor
6. 10,500' string of #4 cable
7. 350 kVA variable speed drive and associated transformers

The pump was set just above the perforations and operations began at about 55 hertz. The well was stabilized at a producing rate of 1334 BPD and a producing BHP of 2140 PSI. If this data point and the other two data points are used to calculate the well's inflow performance then the Curve 2 in Figure 4 is generated.

The general Vogel equation described by Richardson and Shaw Ref. 5, was used to generate Curve 2 and Curve 3. The general Vogel equation is written:

$$Q/Qmax = 1-V(Pwf/Pr) - (1-V)\ (Pwf/Pr)^2$$

The points at the largest rates and draw downs were used to solve for V and Qmax and to generate these curves. Finally the well was produced at the maximum speed of 70 hertz. This is the speed that the motor loaded to full load. A production rate of 1672 BPD at 940 PSI BHP was attained. Again the Vogel equation was applied. Curve 3 in Figure 4 is the solution to this equation. It can be seen that the curve is not a very good fit for this well. As a matter of fact the well acts like there are multiple reservoirs involved or some type of permeability change occurred while testing. See Ref. 5. Regardless of the explanation, this well could only have had equipment correctly sized by testing it near the final operation point.

The operator was charged $450.00 per day for the supplied equipment for the 20 day test period. The operator elected to test the well for an additional 10 days at a cost of $300.00 per day. The well went from an initial rate of 46 BOPD and 310 BWPD to 184 BOPD and 1488 BWPD or an increase of 138 BOPD. The use of this test system allowed for the correct sizing of a constant speed submersible system for this well. At the conclusion of the 30 day test a 406 stage G48 pump with a 150 h.p. motor was designed for the well. After the equipment had been in the well for over 60 days it was producing 1530 BWPD and 116 BOPD. This operating point is plotted on Figure 4.

Case Study No. 2

Case 2 involved a company that had little production data and no submersible pump experience. The well was being produced by hydraulic lift operating at full capacity.

Casing Size = 5 1/2", 17#

Tubing Size = 2 7/8" EUE 8RD

Perforations Depth = 11,700'

Static BHP = 4500 PSI

Q = 95 BOPD and 1055 BWPD

The operator was uncertain of the producing fluid level, but knew it was high. They were limited to approximately 3000 BFPD by their surface facilities for disposal of water. The well had been estimated to produce 3000 BFPD from a producing fluid level of approximately 4500 feet from the surface. Designing a system to meet these parameters would have required:

Motor = 175 H.P.

Pump = 282 Stage, DN3000

Cable = 4500' #4 Cu Parallel

Transformers = 3 - 75kVA

Control Panel = 2500 Volt

The approximate cost to purchase a unit of this size would be $61,500.00. Before investing the capital to purchase the equipment the operator chose to test the well first.

The variable speed test unit installed was rated at 1500 to 3000 BFPD and set at 5500 feet. After completing 15 days of testing at a rate of 3180 BFPD the fluid level had stabilized at 1700 feet from surface (vs the 4500 feet they estimated). The oil production went from 95 BOPD to 290 BOPD and the water from 1050 BWPD to 2890 BWPD. Using this information the smaller equipment listed below was designed for the well.

Motor = 87.5 H.P.

Pump = 125 Stage, DN3000

Cable = 2200' #6 Cu Round

Transformers = 3 - 37.5kVA

Control Panel = 1500 Volt

Total costs for this equipment, including the well test, was $33,365.00. This was a savings in excess of $28,000.00 from the initial design. Had the initial design been installed then approximately 1200 PSI of back pressure would have been needed at the well head to maintain the 3000 BPD rate. This back pressure would have caused an additional $3,400.00 per month in electrical cost. A special note should also be made that future savings will result when the equipment has to be repaired.

<u>Case Study No. 3</u>

This well was selected as a test candidate due to the producing fluid level being at the surface. Offset wells in the field were being produced by ESP lift. Production on these wells ranged from 1000 BFPD to 2500 BFPD with fluid levels from 3500 feet to 7000 feet. This particular well was being lifted by a beam unit. The following well information was available for designing a test system.

Casing Size = 5 1/2", 14#

Tubing Size = 2 3/8" EUE 8RD

Perforations Depth = 7085' - 7091'

Present Production = 250 BFPD

A variable speed test was designed for 660 BFPD to 2070 BFPD and installed in the well. Within hours after start-up it was discovered the well was pumping off. After several attempts to run the equipment as slow as possible it was determined the well had skin damage and could not be produced with the test equipment. The equipment was pulled and a work over was done. The well was then put back on beam pump. The well responded by producing 85 BOPD. The fluid level remained very high, but it was decided not to run a submersible pump back into the well because the allowable for the field was at capacity.

While the well did not respond favorably at first to submersible lift, it was successful from an economic standpoint. A complete ESP unit with the capacity of 1000 BFPD and total head of 4000 feet in 5 1/2" casing would have cost the operator approximately $25,000.00. Couple this with associated expenses for a well servicing unit, electrical contractors, ESP technicians and freight of approximately $2,500.00 and the production company would have spent close to $27,500.00. The test charge was $5,000.00. With the associated charges included, the operator was able to save an estimated $20,000.00 from prematurely purchasing a new unit.

Case Study No. 4

Case 4 is where the operator reopened another zone that had not produced in over thirty-five years. The well had been drilled in the mid 1940's by another production company. From information that was available, this well had flowed approximately 3000 BPD for six years. Over the next few years the well gradually "watered out" to a four percent oil cut and 1000 BWPD. During this period of time it was uneconomical to produce artificially. The zone was squeezed off and the well produced from a higher zone. Gradually the production in the well slowed to 2 BOPD and 3 BWPD.

Knowing the past history, the operator felt the well would produce at least 2500 BFPD. At a cut of 4% the well would yield 100 BOPD. The operator also had a theory the oil in an adjoining reservoir had migrated via gravity to a "secondary oil cap" and if they could move large volumes of fluid there could be an increased oil cut. The economics of having a well test available to prove their theory was a factor in pursuing the project. The well was then drilled out and re-perforated.

A test program was designed for a producing range from 1500 BFPD to 3500 BFPD setting at 5700 feet. The unit was started at 40 hertz and stabilized at 2400 feet and 1800 BFPD. Over a period of 4 days only a trace of oil was produced. On the fifth day the well produced 130 BOPD. Throughout the next 10 days the well went from 180 BOPD to 664 BOPD at a maximum frequency of 45 hertz. Total volume peaked at 2337 BFPD. It should be pointed out the equipment was capable of producing much more fluid at higher speeds. The equipment had to be shut off before the test period was over due to the well making the entire lease allowable.

Not knowing what the well would do in the near future and having a large volume available, the operator purchased a submersible unit identical to the well test system, including the variable speed controller. This will enable them to adjust the speed of the equipment as the oil in the well declines. The oil rate has stabilized at 360 BPD at 40 hertz.

Summary

It is well documented that proper sizing is essential to successfully produce a well with ESP lift. Using the variable speed test can be an economical approach and valuable tool for providing the required information. Since the testing service began in 1985, only sixty percent of the wells tested ultimately result in a permanent ESP installation. For this reason alone strong consideration should be given to testing the well before purchasing a new unit.

In addition, the operator can answer many questions they may have as to how the well will respond or perform at reduced bottom hole pressures. For the wells that are eventually placed on ESP lift, the increased production during the test will generally pay for the test itself.

Some of the newer test units are being equipped with radio telephone communications back to the central office. The computer at the central office calls the test system on a regular schedule. It will request the various operational parameters including the bottom hole pressure. If the pressure is varying from the desired set point pressure, the central computer can then make the appropriate speed correction. Of course, any faults that might have occurred will also be detected and reported to the operator at the central office. The nearest available service technician can then be dispatched to correct the problem.

References

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Pump Performance Curve
100 Stage — D1350 — 60 Hz
400 Series — 3500 RPM

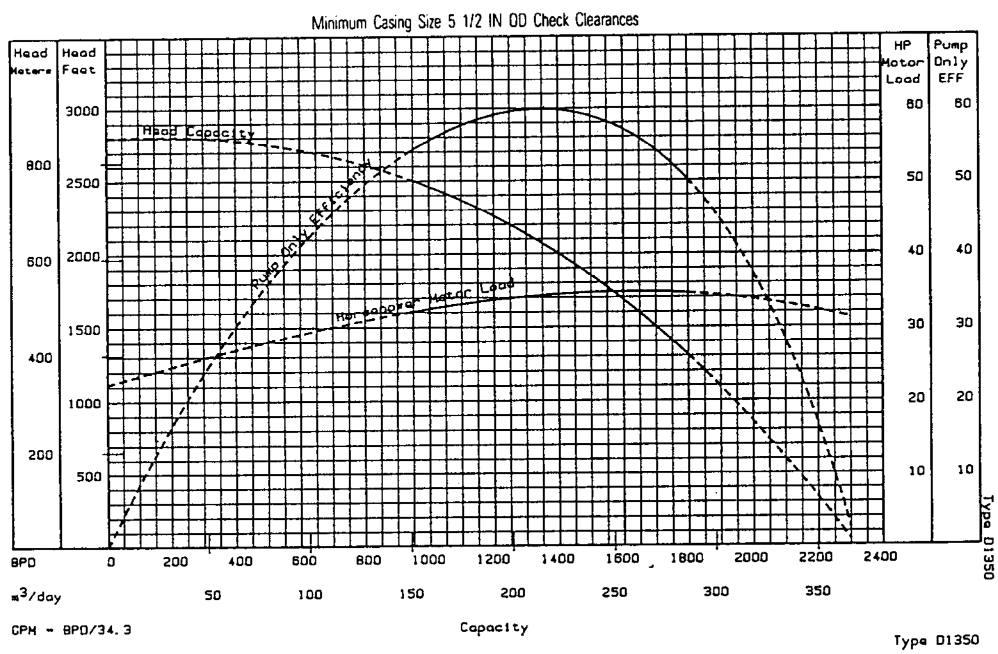

Figure 1

Pump Variable Frequency Performance Curve
100 Stage — 400 Series — D1350 60 Hz/3415 RPM
Minimum Casing Size 5½" O.D. Check Clearances

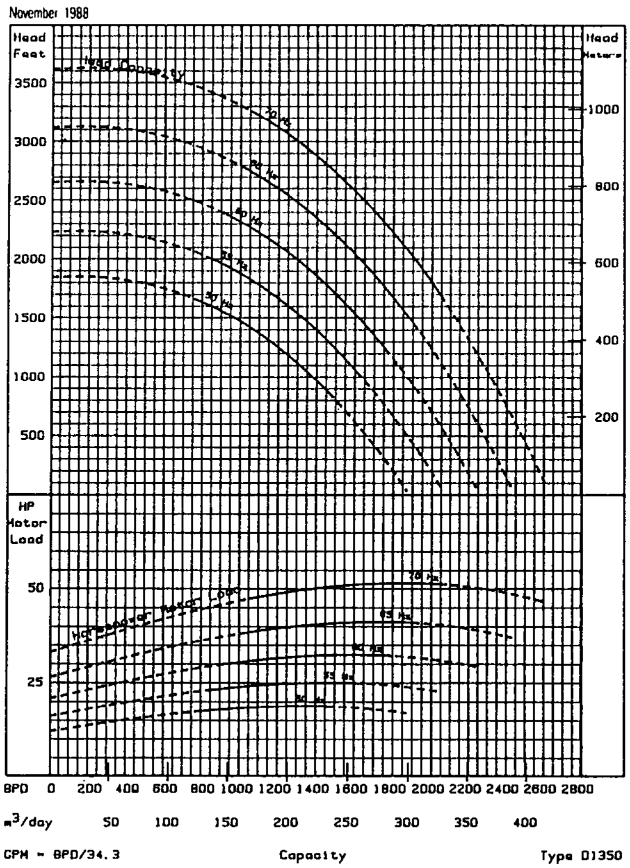

Figure 2

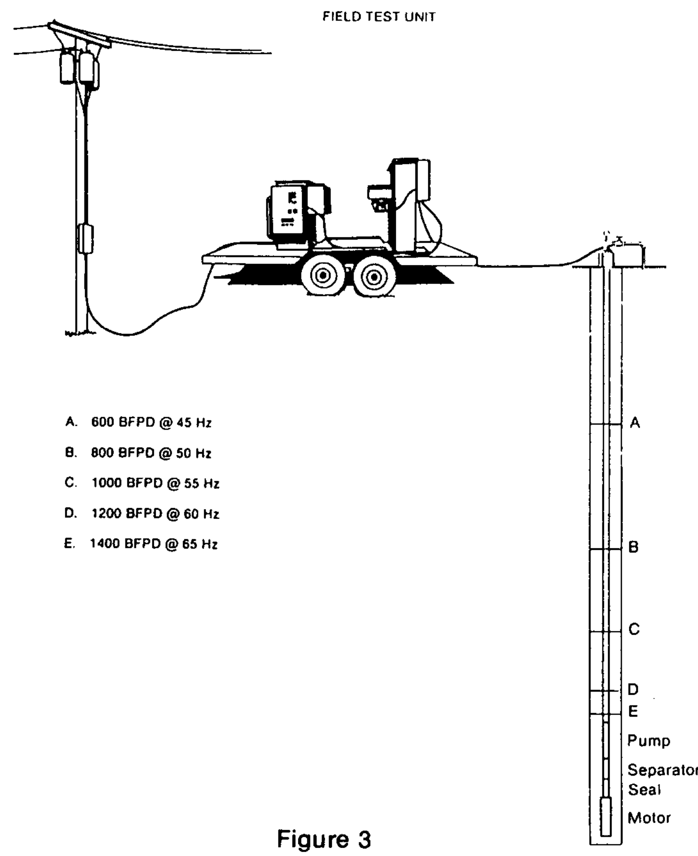

Figure 3

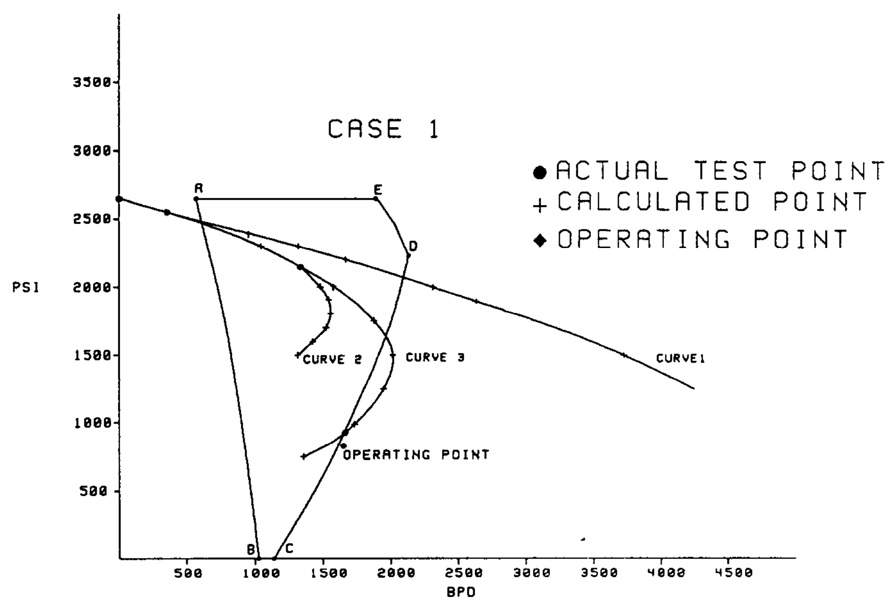

Figure 4