Electrical Submersible Pump Analysis and Design

May 30, 2001

Abstract

Case Services' software provides production optimization for a variety of different methods of artificial lift. This paper discusses the dominant factors in electrical centrifugal submersible pump design and monitoring. Emphasis is placed on three areas:

- Well inflow performance behavior.
- Fluid Pressure-Volume-Temperature and phase behavior.
- Pump equipment performance specifications.

An examination of fluid dynamics within a centrifugal pump provides appreciation for the need to analyze the pump "one stage at a time." The importance of individual pump testing is also identified.

This paper focuses on the three ESP products in the csLIFT suite, csSubmersible, csSubsAnalysis, and csSubsDesign.

Methods are proposed by which the pump, motor, producing formation, and fluids are considered a complex system, which can be modeled by csLIFT computer software. csSubsAnalysis and csSubsDesign provide a basis for the prediction of the equilibrium point at which a particular set of equipment might operate under specific well conditions. csSubsDesign permits an analyst to compare a number of designs for desirability.

Further discussion illuminates the value of periodic monitoring of electrical centrifugal submersible pump installations with csSubsAnalysis. Methods are proposed by which monitoring can identify changes in operating conditions which could adversely impact pump life.

Introduction

Centrifugal pumps powered by downhole motors have been used for decades to lift fluids from oil wells. These pumps and their coupled motors are commonly referred to as "Electrical Submersible Pumps" or "ESPs". In recent years, the meaning of the term "ESP" has become clouded with the application of downhole electric motors coupled to progressive cavity pumps. However, the industry still refers to the more conventional centrifugal pumping equipment using the term "ESP".

This paper outlines some of the classical considerations for analyzing, designing, and monitoring of downhole centrifugal pumps. The term "ESP" is always used as an abbreviation for "downhole centrifugal pump powered by a coupled electric motor".

Experience has shown that proper design and application of ESP equipment rests on three pillars:

- Understanding the well's productivity.
- Understanding the fluid ratios and phase behavior of the fluids produced by the well.
- Careful analysis of activity in each stage of the actual installed pump.

Failure to accurately model the well's inflow performance behavior will inevitably result in over-sizing or under-sizing the pump. In the absence of a variable frequency drive for adjusting pump output, this can be disastrous. An oversized pump will "pump the well off". Typically, a "pump off" condition will trigger a "current underload" shutdown of the motor. The well will remain "down" for a predetermined period of time and then start–up again. This behavior is commonly referred to as "cycling". Since startups create great strains on motors and pumps, cycling will often lead to premature equipment failure.

Conversely, an undersized pump will fail to achieve optimum production. Once this is detected, the equipment may have to be replaced. Regardless of whether the equipment is replaced, an undersized pump will significantly reduce the well's rate of return (ROR).

The types of fluids being pumped, and the response of those fluids to changes in temperature and pressure have a tremendous impact on pump performance. Proper design and monitoring requires an accurate description of the Pressure-Volume-Temperature, and phase behavior of produced fluids.

Finally, the pump must be considered as a series of individual stages (or individual pumps). In many cases, each pump stage compresses the produced fluids and passes a different volume (although same mass) of fluid to the next higher stage. This results in different head, break horsepower, and efficiency ratings for each stage of the pump.

In addition, it is crucial to analyze pump performance based on a "known good" condition. Experience has shown that each serialized pump demonstrates unique performance data. Therefore, a factory pump test should be obtained before the pump is installed in a well. The data from this test can be used throughout the equipment life for accurate performance analysis.

This discussion is limited to conventional applications of centrifugal pumps – specifically excluding:

- Pumps installed below the producing formation.
- Downhole gas separation.
- Variable frequency drive considerations.

Focus is placed upon the pump itself. The downhole motor is discussed only in passing. Steady-state operation (no pump cycling) is also assumed.

The Basics

This section describes the formulas that are the basis for the csSubmersible suite's calculations.

When employing any pumping method, optimum artificial lift is achieved only when the pump is closely matched to the well's ability to produce fluids. This is especially true with centrifugal pumping. Before the pump design process can even begin, an accurate model of the well's inflow performance must be developed.

How Much Will It Make?

Figure 1 is a rough depiction of the way a producing formation might respond to wellbore pressure.

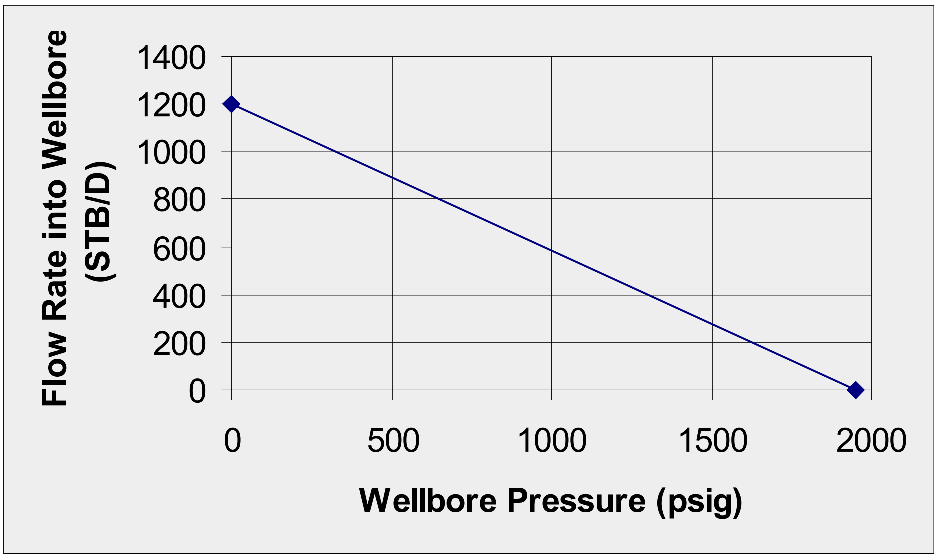

Figure 1: Formation response to wellbore pressure

When the relationship between flow rate and pressure can be described as a straight line on a Cartesian plot, we use the term "productivity index" (PI) to describe the slope of the line. If we know the PI of a well, we can predict how flow rate will change in response to a change in bottom hole pressure:

$$\Delta \text{ Rate} = \Delta \text{ Pressure} * \text{PI}$$

Although flow rate is really a function of pressure (pressure is the independent variable, and as such, should be plotted in the "X" axis), the data from Figure 1 is usually plotted with pressure as the vertical axis and with the flow rate expressed in equivalent surface volumes. Figure 2 provides an example of this format.

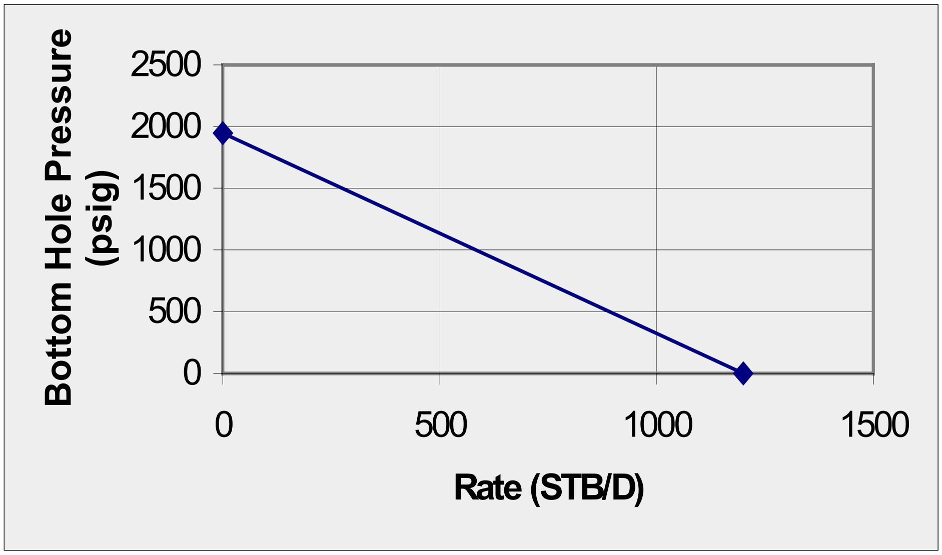

Figure 2: Traditional well productivity plot

The productivity index concept is simple to use. Of course to define a line, you only need two points. Since the PI line always passes through the point (rate=0,pressure = static reservoir pressure), a single stabilized well test point (measured surface flow rate, observed bottomhole pressure) provides all the additional data required to define a well's PI. The bottom hole pressures used in this calculation can be derived using surface casing pressures and observed fluid levels.

PI = (measured flow rate)/(static reservoir pressure – pumping bottom hole pressure)

Note that PI is usually expressed as a positive number.

Although the PI concept is simple and powerful, it is not universally applicable. Flow effects such as the presence of free gas in the reservoir pore space cause many wells to exhibit a rate-pressure profile that is non-linear. Figure 3 is an example of another pressure response model proposed by Vogel. Vogel's model was derived from a computer model, but it has been shown to be useful for wells producing significant amounts of gas.

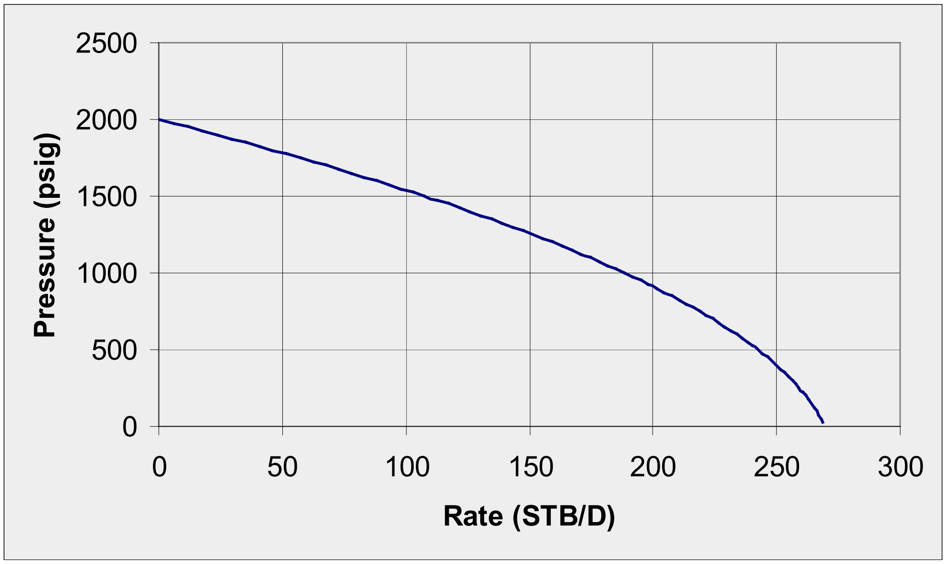

Figure 3: Example of a Vogel inflow relationship

Vogel's inflow performance relationship – like the PI relationship – can be derived from static reservoir pressure and a single stabilized well test.

Other authors have published adaptations to the Vogel relationship, which account for oil bubble point and changes in flow efficiency (skin damage and stimulation). One of the more popular models is a hybrid of the Vogel and PI relationships used for under-saturated oils – where reservoir pressure is above the oil bubble point. These models all have applicability under different reservoir conditions.

The csSubmersible suite provides the user with the ability to choose different models for calculating inflow performance relationships. The user can choose PI, Vogel, or hybrid from a dropdown menu.

The PI concept is generally considered to be applicable for wells producing high water volumes and very little gas. If significant gas volumes are expected, or if a very large drawdown is anticipated, one of the Vogel derivatives would probably be more appropriate. However, it is prudent to test the subject well at multiple rates and plot your own inflow performance curve. This practice assists in tuning and validating the inflow performance relationship, which will be used in artificial lift design.

The discipline of pre-design well testing is commonly overlooked in onshore operations. This is probably due to the predominance of sucker rod pumping in onshore fields. Rod pumping provides considerable flexibility for adjusting surface equipment to optimize pumping efficiency. However, submersible centrifugal pumps do not afford such luxuries. Unless a variable frequency controller is included, very little about an ESP installation can be "tuned" after commissioning. Remember that an error in judgement about the well's ability to flow could result in premature equipment failure, and costly equipment changes. The effort invested in well pre-design testing can reap significant savings over the life of the well.

How Much Does It Take?

The previous discussion about inflow performance dealt entirely with flow from the producing formation into the wellbore. In order for the fluid to get to market and generate revenue for your company, it must also flow up the producing conduit (usually the tubing) to the surface.

Quite simply, fluid will flow up the tubing only if the pressure at the tubing intake (bottom of the tubing) is greater than the hydrostatic "weight" of the fluid, plus the friction pressure losses in the tubing, plus the tubing discharge "backpressure." If tubing geometry, temperatures, fluid properties, and tubing discharge pressure are known, a multi-phase flow model can be used to predict the pressure required at the tubing intake to push the fluid to the surface. If the required tubing intake pressure is calculated for a set of circumstances over a range of surface flow rates, a plot similar to Figure 4 can be constructed.

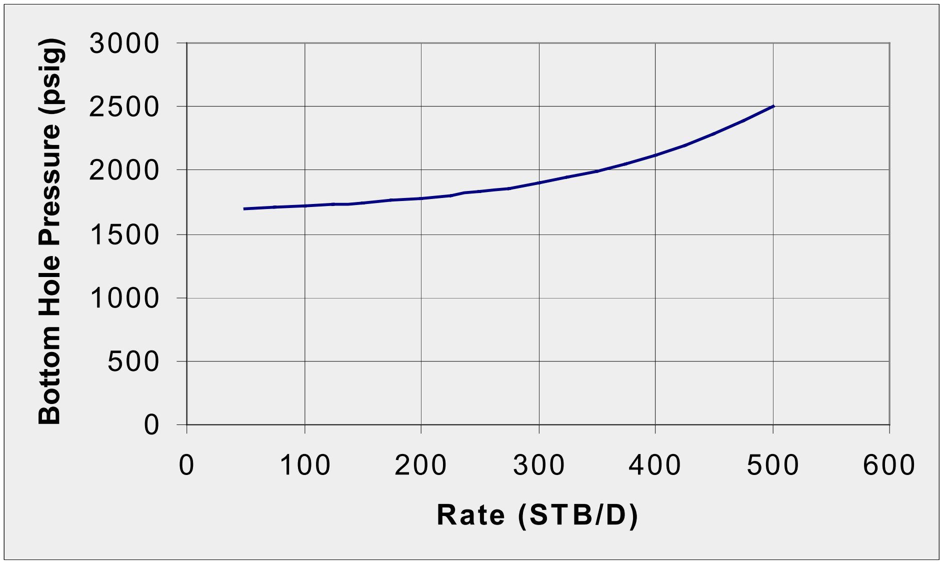

Figure 4: Example of a tubing intake requirement plot

Will It Flow?

Previously, we plotted a curve describing how much fluid the *formation* can produce at different bottom hole pressures. In addition, we now have a plot of how much pressure is required to push fluid to the surface at varying rates. csSubsDesign places both of these curves on the same plot (Figures 5 and 6). That creates a very powerful tool for analyzing wellbore dynamics. Note, in making the transition from Figures 3 and 4 to Figures 5 and 6, all pressures had to be corrected to some common depth.

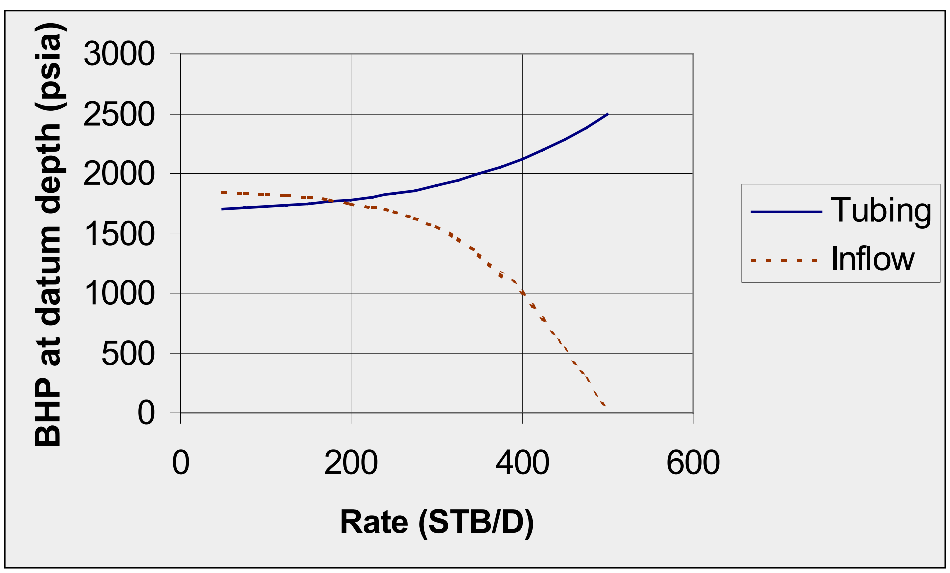

Figure 5: Comparison of tubing intake requirements and well inflow performance (Well 1)

In Figure 5, the inflow performance and tubing intake curves intersect. This intersection point (surface flow rate, bottom hole pressure) is the point at which the well should actually flow under stabilized conditions. In Figure 6, however, the curves do not intersect. This well would not flow at any rate. A pump must supplement the energy supplied by the reservoir in order to produce fluid at the surface. The precise amount of energy needed is represented by the vertical separation between the two curves.

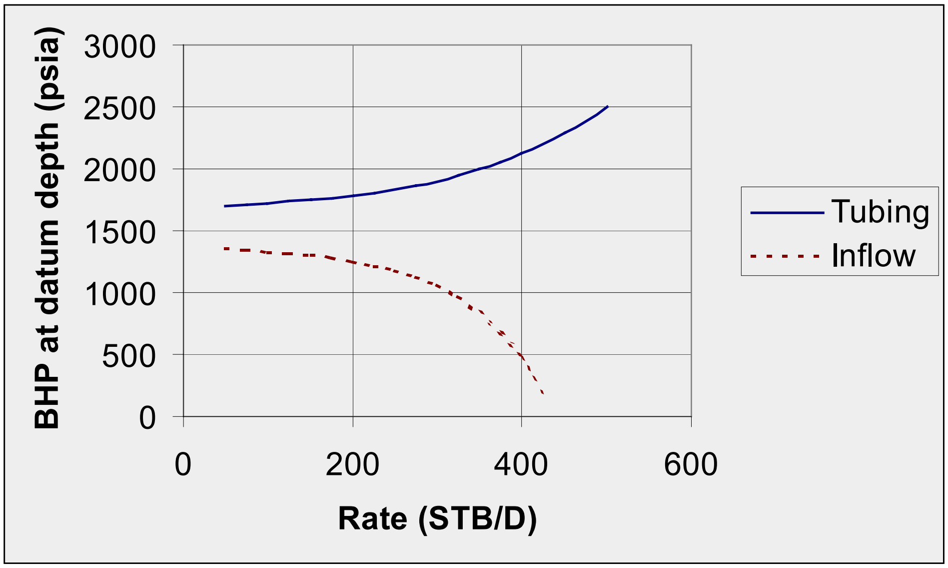

Figure 6: Comparison of tubing intake requirements and well inflow performance (Well 2)

How Much Do We Have To Add?

By measuring the difference between the tubing intake pressure requirement curve and the well's inflow performance curve, we obtain a curve representing the pressure increase required across the pump as a function of rate. Figure 7 shows this curve for the two wells in Figures 5 and 6. Note that the curve for Well 1 becomes negative at low rates – reflecting that the well will flow without pumping at those rates. If it is desired to produce the well at higher rates, the curve is still useful for identifying the pump energy required that achieves the target rate.

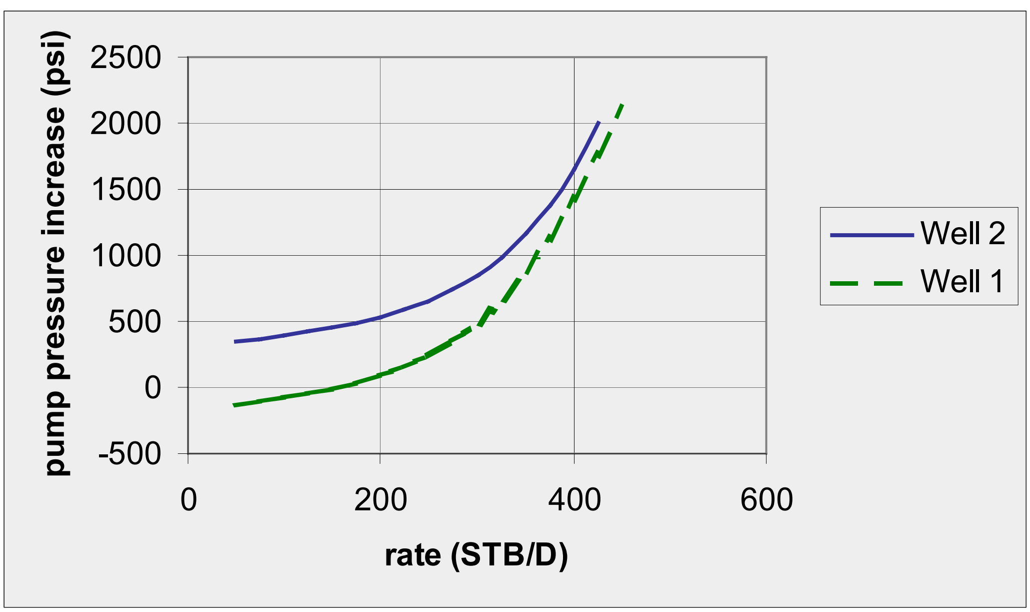

Figure 7: Well requirement curves for Well 1 and Well 2

Let's Go Shopping!

csSubsDesign provides the curve in Figure 7 that provides the information needed for accurate pump selection. If a target rate is the driving factor in pump selection, then Figure 7 can be used to derive the required pump pressure increase to produce that rate. If the objective is to optimize on some other parameter (efficiency, cost per barrel lifted, etc.), Figure 7 can be used to identify pumps which will cause the well to produce, and the different pump cases can be prioritized by the optimizing parameter.

Note that the discussion to this point is independent of the pumping technique used. The curve in Figure 7 could be used as the basis for rod pump design, progressive cavity pump design, or centrifugal pump design. This would not be true for gas lift, because gas lift is not a pumping method.

Welcome To The Centrifugal Pump Store.

If the option of an ESP is to be considered for a particular well, the designer must compare the "well requirements" curve (similar to Figure 7) with the performance characteristics of different pumps. These performance characteristics are typically communicated in the form of "pump curves" (Figure 8). In csSubsDesign, a single graph will contain curves for dynamic head, shaft horsepower requirements, and efficiency. The curves are typically based on fresh water and a fluid viscosity of 1 cp. The horizontal axis represents actual rate through the pump. Head, brake horsepower, and efficiency are usually represented for more than one pump stage.

It is a good practice to operate the pump close to this high efficiency point (known as the Best Efficient Point or "BEP"). Therefore, one of the main pump selection criteria (along with physical size) is the pump's advertised BEP. Once a pump type has been selected, the number of stages in the pump is calculated based on the pump's "head" curve and pressure requirement derived from the "well requirements" curve.

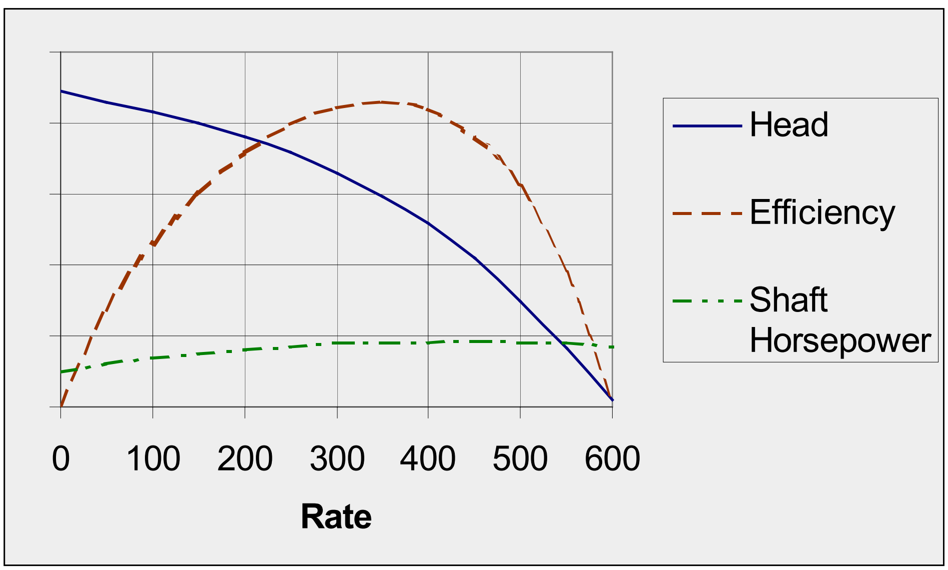

Figure 8: Pump performance curves

Head Versus Pressure

In our previous discussion of wellbore dynamics, we formulated all relationships in terms of pressure (psia). This is appropriate because producing formations respond to pressure changes and tubing energy loss models typically work with pressures.

The physics involved in centrifugal pumping causes the pump to produce fluid energy, which is related to the density of the pumped fluid (commonly known as "head"). For a given pump at a specific rotational speed, the output of the pump (in feet of head) will be constant regardless of the fluid being pumped. However, the pressure output (in psi) and the shaft horsepower required to drive the pump (brake horsepower) will change in direct proportion to the density of the fluid being pumped.

Since matching a pump to a producing well requires a common set of measurement units (either feet of head or psi of pressure), we will either have to convert the well pressure requirements curve to head or convert the manufacturer's pump curve to pressure. The following discussion will reveal that this is not always a simple matter.

Fluid Dynamics Inside The Pump

Design and analysis of centrifugal pump installations requires a keen understanding of the fluids that move through the pump. In some cases – such as high water cut wells with low gas production, these dynamics can be overlooked with negligible side effects. In many cases; though, the fluid exiting the pump discharge can be dramatically different from the fluid that entered the pump intake. In these cases, csSubs suite provides detailed analysis so that great care can be taken to insure that the proper pump is selected.

Pressure, Volume, Temperature

It is well known that the physical properties (density, gas solubility, viscosity, compressibility) of petroleum reservoir fluids change with changes in temperature and pressure. This behavior is commonly referred to as the Pressure-Volume-Temperature (PVT) behavior of the fluid.

In the bottom of the wellbore, there is typically some mixture of oil and free gas and water. Some separation between the phases occurs in a normal wellbore, but inevitably, a mixture of oil, water, and gas enters the pump intake. As this mixture of fluids is subjected to work by the pump, it's pressure increases. This pressure increase causes the oil phase to shrink. It also causes the free gas phase to shrink dramatically. Additionally, gas is pushed back into the liquid phase – changing the oil's viscosity, compressibility, and density.

If the well is producing from a CO_2 injection field, still other changes take place. CO_2 is highly soluble in both oil and water. So, as the pump works on the fluid mixture, CO_2 gas will be absorbed in the water – changing the water's properties along with those of the oil.

Fortunately, the phenomena discussed above are repeatable for a given set of reservoir oil, water, and gas. This allows us to model the fluid PVT behavior. For a given reservoir fluid system, if we have a pressure and a temperature, we can estimate density, viscosity, solubility, and compressibility using one of the following types of models:

Custom equation of state:

This is a mathematical model based upon the molecular composition of the reservoir fluids. Custom equations of state are quite expensive and are not commonly available for production equipment design purposes.

PVT laboratory analysis:

Sometimes, a downhole sample of the reservoir fluids is obtained for analysis. In a laboratory, the fluids are subjected to pressure changes – usually while temperature is maintained at reservoir temperature. This procedure provides a tabular presentation of measured fluid properties at varying pressures. Typically some other method has to be used to adjust this data for variations in temperature.

Published correlations:

This is the most commonly used technique – usually because the other two techniques are not available. It consists of using mathematical equations resulting from "curve fits" of a number of field PVT samples.

csSubsDesign provides the user with the ability to use any one of the three models. Regardless of the model used, consideration must be given for the presence of injected CO_2. Failure to include CO_2 effects in PVT modeling can result in gross misunderstanding of fluid PVT behavior.

How Do You Spell Relief?

Typically, the fluid produced by the formation into the wellbore at pumping bottom hole conditions is a mixture of oil saturated with dissolved gas; water saturated with dissolved gas; and free gas. Under stable operating conditions, this same total mass of material is produced by the well into the surface separation equipment. But, in a normal installation, these fluids can travel to the separator via alternative paths:

- Through the pump and up the tubing.
- Through the casing.

During a period when the subject well is passing through a test separator, the casing valve can be closed and the build-up in surface casing pressure over time can be recorded. By combining this rate of pressure change over time with gas composition information, a reasonably accurate estimate of gas accumulation rate in the casing can be calculated. This accumulation rate is – in effect – the rate at which free gas is normally produced through the casing. By subtracting this amount from the total gas flow rate at the separator, the amount of gas that passes through the pump can be derived. Remember that much of this gas is dissolved in the oil (and maybe the water) at downhole conditions.

So, What Is The Rate Through The Pump?

Returning to the process of selecting the proper pump for a particular application, the question once again becomes "What rate do we design for?" The answer to that question lies in understanding how the fluids produced through the pump behave as they pass through each stage.

At the bottom stage, saturated oil, water, and possibly some free gas enter the pump intake and are subjected to some amount of work. The work increases the pressure of the fluid and forces some of the free gas into the oil (and water). This same mass of fluid - now occupying less volume – is passed up to the next stage. The process continues with each successively higher stage operating on a smaller volume than the stage below it.

In many applications, this liquid compression can be very slight, and the rate through the top stage of the pump is only one or two barrels per day less than the rate at the bottom stage. When free gas exists at pump intake conditions however, the change in rate can be dramatic. The bottom stage in the pump might be pumping fluid at two or three times the rate of the top stage.

Since centrifugal pumps do not possess wide efficient operating ranges, each individual stage of the pump must be analyzed. This permits the designer and well analyst to understand which stages of the pump are operating efficiently and which stages are operating outside of the manufacturer's recommended operating range. By looking at a chart in csSubsDesign, the user can instantly see a comparison between the actual operating range and the manufacturers' recommended range.

If a dramatic change in liquid rate through the pump is expected, a "tapered" design can be implemented. csSubsDesign provides the analytical information for each stage in the tapered pump.

A Pump Curve For Every Well

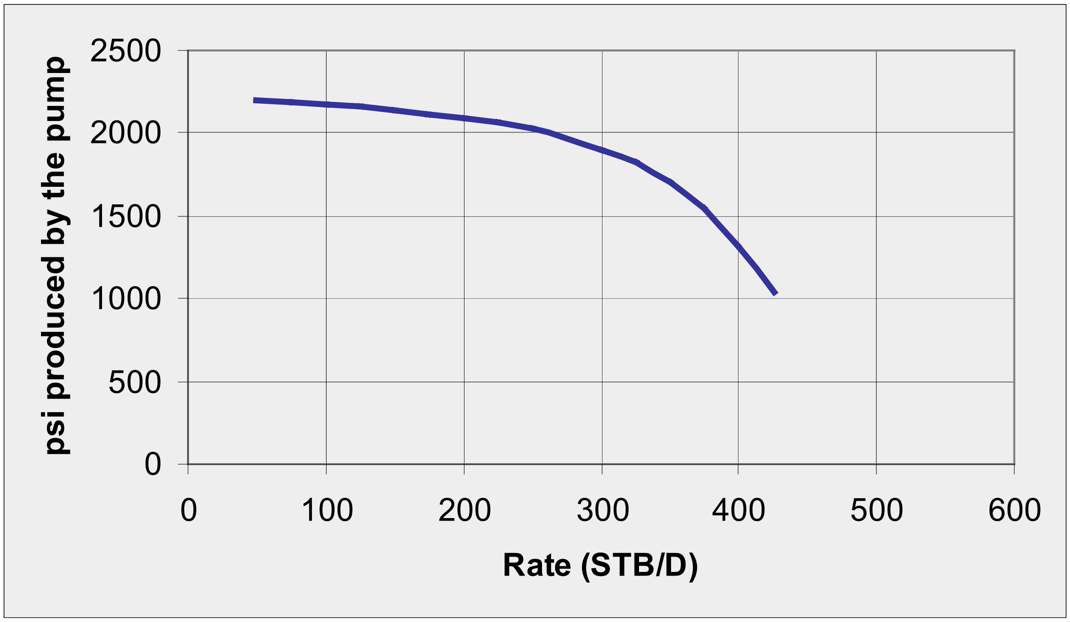

Figure 9: Example of a well-specific pump curve

By combining our fluid PVT model and the manufacturer's pump performance curves, csSubsDesign can add anticipated well operating conditions and "water cut" information to derive an estimate of pump energy output (in either psi or feet of head) for a given flow rate. Performing these calculations over a range of rates results in a unique "pump curve" similar to Figure 9.

Note that this figure represents much more than the manufacturer's performance curve adjusted for the average density of the fluid passing through the pump. It is an extremely accurate model of how the pump would perform in the subject well. In addition, this "one stage at a time" curve can provide a realistic depiction of the behavior of a tapered pump.

Actual Vs. Advertised Pump Performance

Although oil well centrifugal pumps are made from interchangeable parts, the unpleasant truth is that they each have unique personalities. In recent years, oil operators have learned through pump testing that each pump exhibits its own performance curve. Sometimes these actual tested performance curves can vary from the manufacturer's advertised curves by a significant percentage. The American Petroleum Institute (API) has developed standards for individual pump testing and reporting of test results. API has also published standards for the maximum amount of deviation between published performance specifications and actual tested specifications. This information is contained in API Recommended Practice 11S2 (API RP11S2).

It is extremely important to obtain true tested pump performance data for each pump prior to installation in the well. Consult your manufacturer for details on the cost of this service. Once the information is obtained, it should be compared to published specifications using API procedures *before* the pump is installed in any well.

Note that discharge pressure and pumping rate expectations of the actual downhole equipment should be based on the true tested performance curves instead of manufacturer's published curves. This usually requires another "iteration" through the pump design process to establish a more realistic estimate of the equilibrium point at which the equipment will operate.

Putting It All Together

For a particular well and tubing combination, csSubsDesign can produce a plot similar to Figure 7, to obtain the amount of pressure which the pumping system would need to provide to make the well flow, as a function of rate. As previously discussed, csSubsDesign can produce a "pump" curve similar to Figure 9 for a given pump with the vertical axis represented as pressure. This is the pressure that would be supplied by this particular pump (under the specified well conditions) as a function of rate.

csSubsDesign plots both of these curves on the same coordinate system and yields a plot similar to Figure 10. Note that the intersection of the two curves on this plot represents the point at which the well would be expected to produce under stable conditions.

Since both the "well requirements" curve and the "pump" curve have been rigorously derived using good models and accurate input parameters, this type of plot can be expected to accurately predict the performance of a given pump in the subject well. Therefore, this technique can be used as a basis for pumping system design.

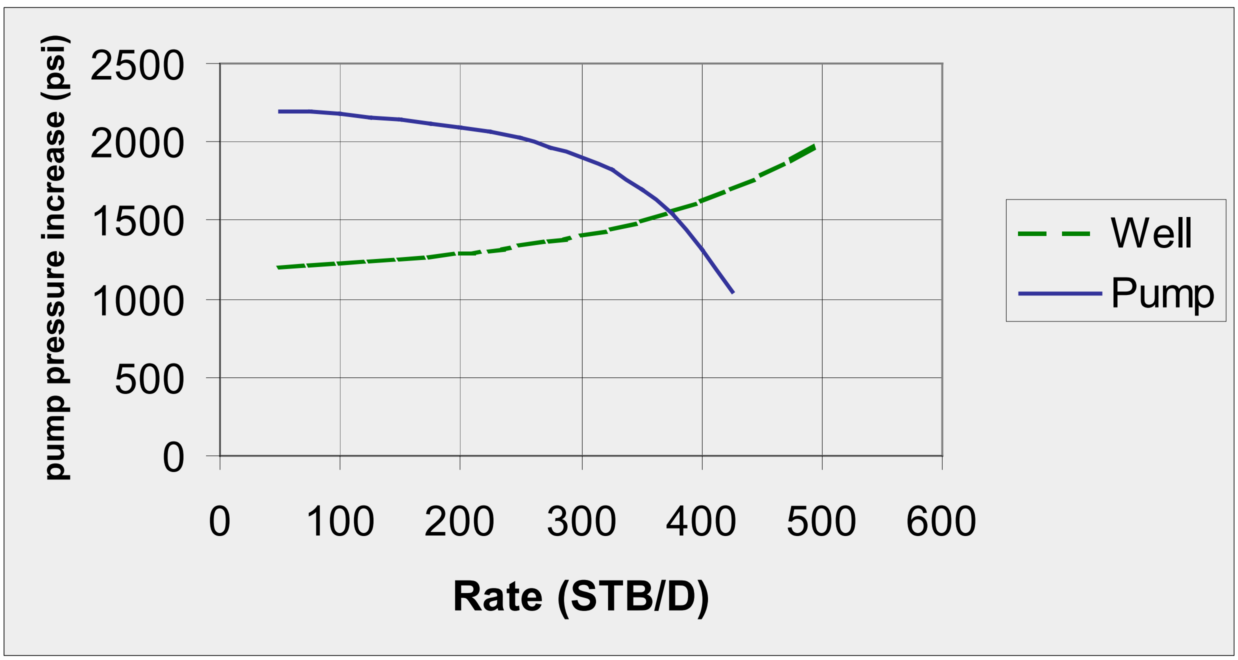

Figure 10: Plotting well requirements and pump delivery together

The calculations for producing Figure 10 for a particular well and pump are quite rigorous. However, the csSubs suite of tools can permit a designer to evaluate pump performance quite quickly. Furthermore, if pump catalog data are available in electronic form, a number of pumps can be imported and evaluated for a given well.

Motor And Pump As A System

RPM "Rules"

Another commonly overlooked feature of centrifugal pump design and analysis is true rotational speed of the pump. Note that pump performance statistics are published at specific revolutions per minute (RPM) value. By American Petroleum Institute (API) standards, this value should be 3500 RPM. This is the "nominal" rotational speed of electrical submersible type motors under 60 Hz alternating current (AC) operation.

As the actual rotation of the centrifugal pump deviates from the published RPM basis, things begin to change rapidly. Pump output volume is proportional to the ratio of the actual RPM to the published RPM basis. Head production; though, varies with the square (to the second power) of the RPM ratio. Shaft horsepower requirements are proportional to the RPM ratio cubed (to the third power). Therefore, it is desirable to predict the pump rotational speed in order to gain an accurate understanding of the behavior of the pump system.

The electrical motor used to drive the pump almost never operates at 3500 RPM. In fact, when the motor is significantly oversized, it may rotate 5 to 10% faster. Under normal loading, however, the motor may only drive the pump to 3400 RPM or less.

ESP manufacturers publish performance curves for motors as well as pumps. These performance specifications come in the form of "RPM as a function of percentage of nameplate horsepower loading". Therefore, csSubsDesign calculates the shaft horsepower required to drive the pump under design conditions so the user can use the motor performance specifications to determine the operating RPM that should be expected when the pump is installed.

However, as stated earlier, the pump shaft horsepower requirement is a function of – among other things – RPM. Therefore, an iterative process is required to accurately model the pump and motor as a coupled system. First, pump shaft horsepower requirements are calculated based on 3500 RPM operation, then the motor's RPM is determined based upon that load. The new RPM value is then used to recalculate pump head, rate, and efficiency – as well as shaft horsepower requirements. Once again, the motor performance specifications are used to determine RPM. The process is continued until the calculated RPM converges.

Many would consider the process described above as "hair splitting". Based on manufacturers' published data, the maximum benefit that one could expect from this exercise is a 3% improvement in rate estimate, a 6% improvement in head estimate, and a 8.5% improvement in break horsepower estimate. However, small percentages in efficiency over the life of an ESP can result in significant savings in operating costs.

Fluids Again

In previous sections, we discussed the process csSubsDesign uses to *design* a centrifugal pumping system. In using csSubsAnalysis for *analyzing* the performance of an existing centrifugal pump installation, yet another variable must be considered.

Recall that shaft horsepower requirements are proportional to the density of the fluids passing through the pump. Therefore, changes in water cut, gas oil ratio (GOR), or gas separation changes will impact pump head generation, and fluid movement rate in complex ways.

For instance, when the fluid density increases, the pump discharge pressure – because it is directly proportional to fluid density – might be expected to increase. However, this increased fluid density drives up shaft horsepower requirements for the motor, and – as a result – reduces the RPM of the pump-motor system in a fixed frequency application. Since the pump has slowed, head production will decline, and the resulting psi output of the pump may not really increase. In fact, the increase in fluid density might cause pressure at the pump discharge to decline. And when the change in tubing fluid gradient is considered, it is impossible to intuitively determine whether observed pressure at the tubing discharge will increase or decrease as a result of this change in fluid density. However, csSubsAnalysis can perform the rigorous calculations required to unravel such a mystery. Without good analysis tools, it is difficult to understand such complex behaviors.

Decisions, Decisions

Understanding Efficiency

The basic efficiency of an artificial lift installation can be loosely defined as:

Efficiency = Work out/Work in

In trying to analyze these systems, it is important to understand the components that contribute to this simple equation.

The "work out" term is typically measured as hydraulic horsepower (flow for a given rate under a certain pressure or head). This is often a good measure of the numerator of the efficiency equation. Accurate calculation requires reasonable estimates of oil, water, and gas flow rates, tubing discharge pressure, and fluid PVT behavior. Note, however, that tubing discharge pressure is a function of well "back pressure". That is, separator pressure and the physical-piping configuration between the well and the separator influence it. Therefore, changes in any equipment downstream of the wellhead will impact tubing discharge pressure, and cause a change in the "work out" term. This means that modifying downstream equipment can result in an apparent change in "well" efficiency when the "work out" term is derived as previously described.

The "work in" term is often trivialized to include only the purchased energy used to drive the mechanical equipment. For an electrical submersible centrifugal pump application, this term would be the kilowatt-hours of electricity purchased.

In fact, there are two sources of energy that combine to drive fluid out of the tubing discharge. The obvious source of energy is that of the artificial lift equipment. An often-overlooked source of energy is the producing formation itself. If the formation energy is ignored, erroneous efficiency measurements will result. More importantly, if the producing formation's contribution changes (due to reservoir pressure decline or formation damage), one might interpret the change in "efficiency" as deterioration of the artificial lift equipment.

Pumping Equipment Efficiency

One useful way to calculate efficiency in an electrical submersible centrifugal pump installation could be referred to as "pumping equipment efficiency". This efficiency reflects the ability of the power cable, motor, and pump to transform electrical energy at the surface into fluid energy at the pump discharge. The simplified equation for this efficiency is:

Pumping equipment efficiency = (Δ Energy through the Pump)/(Kilowatts of electricity in)
Where:
(Δ Energy through the Pump) = Fluid energy at pump discharge – fluid energy at pump intake.

Given reasonable estimates of pump intake pressure, tubing discharge pressure, oil, water, and gas flow rates, and fluid PVT behavior, modeling tools can be used to derive the "Δ energy" term in this equation. However, the calculations are quite rigorous and require computer software support.

The utility of this efficiency measurement is twofold. During the design phase, it can be used to compare the operating costs of various artificial lift alternatives for a given well. The comparison could be between different ESP designs, or between an ESP design and other pumping method alternatives.

After the equipment has been installed, this efficiency calculation provides a useful tool for monitoring the artificial lift equipment. The "pumping equipment efficiency" is fairly insensitive to conditions downstream of the well. The calculation also removes the influence of the well's contribution to fluid flow. Therefore, this value is an excellent tool for surveillance of the cable, motor, and pump.

Well System Efficiency

Once we fully understand the traditional equation for efficiency, we can use it in very practical ways.

We define "well system efficiency" as:

Well system efficiency = (Hydraulic horsepower at tubing discharge)/(Kilowatts of electricity in).

This efficiency measure is subject to all of the influences previously described. However, when it is used in conjunction with "pumping equipment efficiency", it can reveal changes that occur in and around the well. For instance, a decline in "well system efficiency" that is not accompanied by a decline in "pumping equipment efficiency" may be an indication of reservoir depletion or damage. Large anomalies in both efficiency values may be an indication of a tubing leak.

Lifting Costs

Because a major objective of oil production operations is to produce profit, the concept of lifting cost is quite useful. Like efficiencies, lifting costs can be calculated in a number of ways. Rigorous financial analysis requires consideration of such factors as equipment maintenance costs, labor, overhead, and even taxes.

However, simplified measures, which include only direct power costs, can often be used within a given operational group or oilfield to compare artificial lift methods or compare the performance of different wells. These measures are often calculated in the form of dollars per barrel of oil or dollars per barrel of total stock tank liquid based on a fixed electrical cost per kilowatt-hour.

In addition, during the design phase, simple lifting cost calculations can assist in performing value judgements that weigh initial capital expenditures (CAPEX) against long term operating costs. This is particularly true in choosing ESP cables.

The downhole cable in an ESP installation can be a sizable percentage of the total system cost. Since power loss down the cable and cable costs typically have an inverse relationship (power loss decreases as cost of cable increases), csSubsAnalysis provides the information for an economic justification for any ESP cable choice. This economic justification can be based on a comparison of the lifting cost of the alternatives vs. their initial CAPEX.

Which Pump Is Right?

Given a particular well for application of electrical submersible centrifugal pumping, the designer can arrive at any number of pumping system designs. Besides the obvious choice of pump manufacturer, such factors as target production rate, tubing size, pump depth, and pump tapering (in gassy applications) can be varied to produce different artificial lift options.

csSubsDesign permits the designer to quickly evaluate all possible options based upon a range of pump depths, tubing sizes, target production rates, and pump manufacturers. The primary performance parameters (flow rate, efficiency, lifting costs, electrical costs/year) for each option are tabulated. The designer then ranks the options based upon his primary decision criteria, and then an educated decision can be made.

With csSubsDesign, there is no need for a designer to perform each of these calculations manually. Given a simple list of criteria and some information about the well, the computer program identifies all candidate pumps, and models their behavior in the subject well. In addition, the software identifies candidate motors and cables and determines their performance under the specified design conditions.

To facilitate this task, csSubsDesign has access to a complete set of manufacturers', "catalogs" of pump, motor, and cable specifications. These "catalogs" reflect currently available equipment from all recognized vendors.

csSubsDesign permits a designer to identify the optimum design for a particular application in a very short time. This results in increased personal productivity and high quality system design.

After Installation

Once an electrical submersible centrifugal pump is installed in a well, good operating practices and csSubmersible and csSubsAnalysis software tools can be used to monitor the pump's operation.

System View

Recall that in Figure 10, a graphical depiction of pump and well behavior was presented. Note that the coordinate system of Figure 10 involves surface liquid flow rate and pressure increase through the pump. csSubsAnalysis can provide actual measurements of these two parameters (using data from routine well tests along with associated estimates of tubing discharge pressure and producing bottom hole pressure) so a user can plot actual performance data on the same plot. Figure 11 is an example of such a plot.

In Figure 11, several well test points have been plotted along with the well's design curves. Note that all of the test points match – within reasonable error bands – the theoretical operating point of the well/pump system. In this case, actual well test information confirms the accuracy of the design.

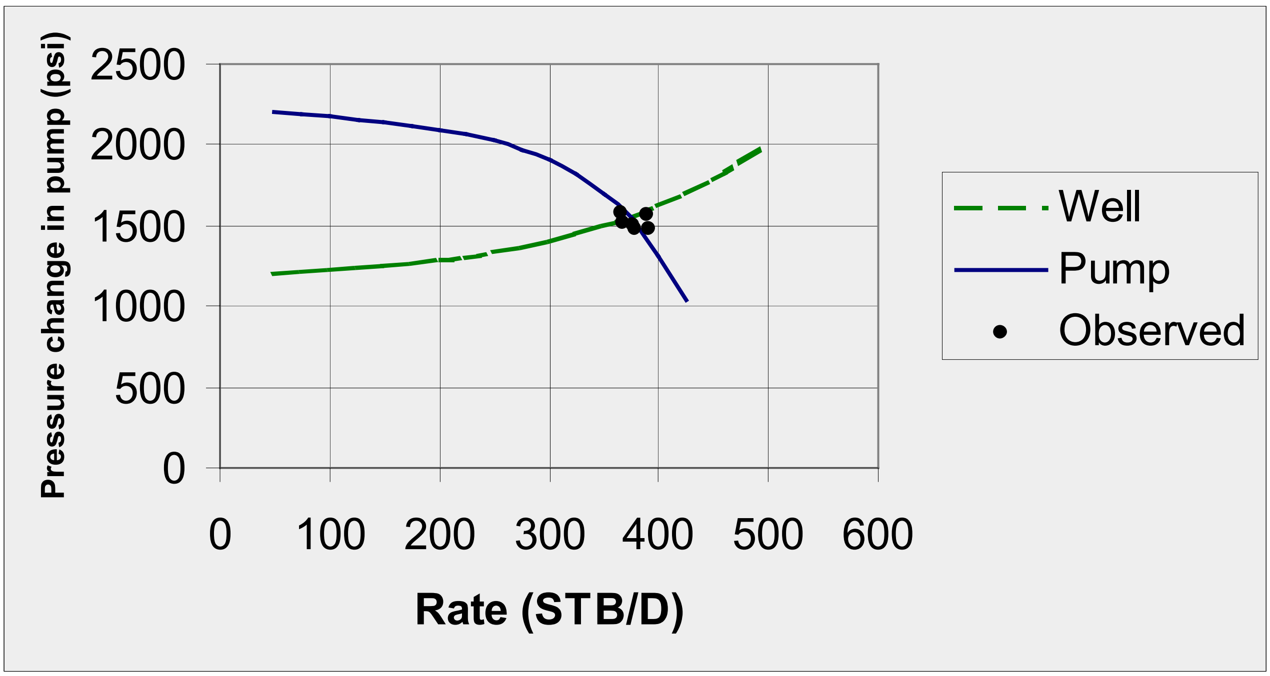

Figure 11: Observed behavior matches designed behavior

Figure 12 depicts a number of well test points clustering at a point which is near the "Pump" curve, but far from the "Well" curve. This plot suggests that the design is in error and that – most likely – the productivity model used for the well was too optimistic.

Figure 12 reveals how such plots can be valuable analysis tools. When a new pump is installed in a well, plotted well test points should cluster close to the intersection of the "Well" and "Pump" curves. If they do not, a calibration procedure should be followed to determine which design parameters are in error. The design curves should then be re-derived and the process continued until actual and theoretical operating points converge.

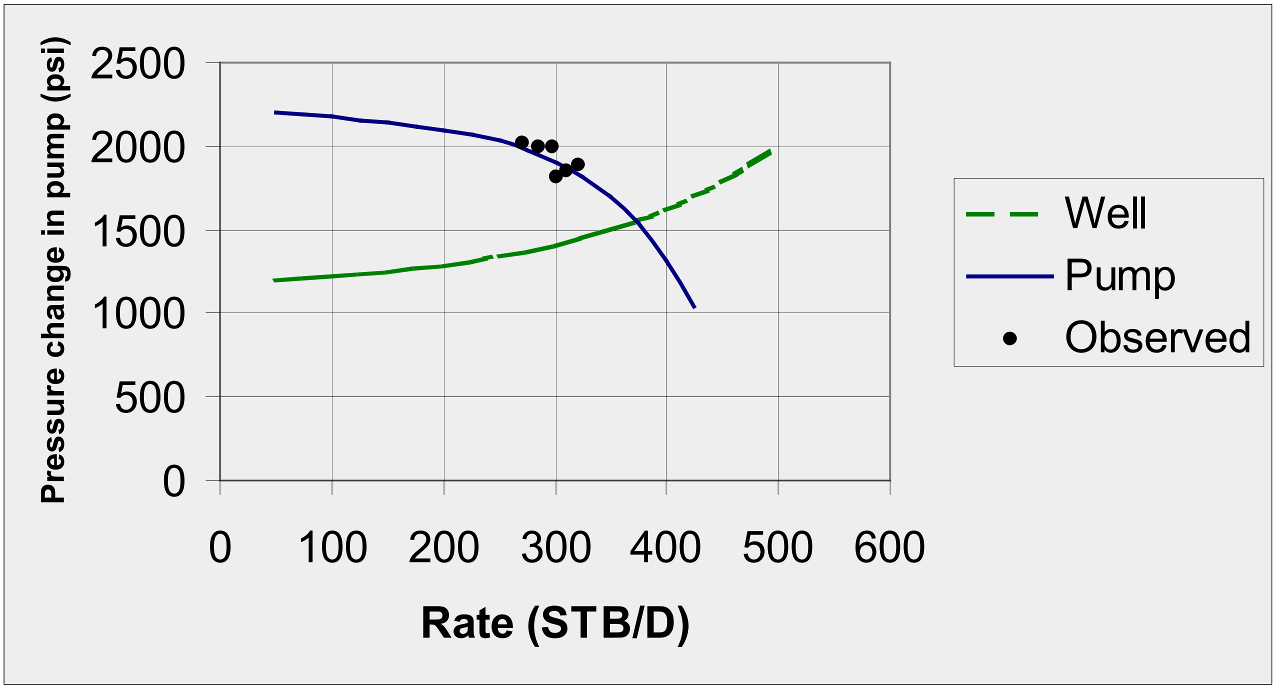

Figure 12: Observed data indicates error in well requirements used for design

As time passes, assuming no changes to the system, the well test data should be expected to remain very close to the theoretical operating point. However, changes do occur, and monitoring of the well using the described technique can provide valuable insight into the nature of these changes.

Over time, the well test data may begin to trend along the "Pump" curve – deviating from the "Well" curve. This behavior is indicative of changing formation conditions (pressure decline or skin damage). Conversely, well test data may begin to deviate from the "Pump" curve and trend along the "Well" curve. This would be an indication of pump performance deterioration. Note that pump performance deterioration does not always mean pump wear.

Pump Internals

Previous sections of this paper discussed the role fluid dynamics inside the pump in causing the flow rate to vary as liquid passes through the pump. This fluid compression phenomenon results in successively higher stages in the pump handling lower rates.

This behavior is highly dynamic, and is dependent on the fluids (oil, water, and gas) entering the pump intake as well as pump characteristics.

The well test performance plots described above take a "macro" view of the pump as it relates to the total producing system. However, detailed calculations should be performed with each well test to determine fluid flow rates for the various stages of the pump. These calculations can be performed any time the tubing discharge pressure, pump intake pressure, and fluid flow rates can be simultaneously estimated.

The resulting detailed flow rate analysis within the pump can reveal changes inside the pump that might cause excessive stress.

csSubsAnalysis provides a report detailing these calculations. A version of the report is available for each analyzed well test.

Conclusion

The csSubs software suite provides proper design and analysis of centrifugal pump installations based on detailed knowledge of three major factors:

- The reservoir's ability to produce fluid into the wellbore.
- The physical characteristics of the produced fluids (oil, water, and gas).
- The actual performance of the installed pump(s) and motor.

In addition, friction pressure losses in the tubing string are presented as an important role in understanding of the entire system.

The motor, pump, well, and fluids operate as an intricately balanced system. In actual operation, an equilibrium point will be reached which reflects this relationship.

In order to accurately design a centrifugal pump installation, a tool such as csSubsDesign is required. It supports the following functions:

- A variety of well inflow performance models from which to choose. The designer uses other means to determine which model best depicts the ability of the well to produce fluids. The "PI", "Vogel", and "Vogel for under-saturated oil" models are most commonly used.
- A variety of fluid PVT models. Actual PVT data tables and industry acknowledged correlations are supported. If the subject well is in a CO_2 flood, the impact of high CO_2 concentrations on PVT behavior *is* included in the model.
- A complete catalog of manufacturers' pump and motor specifications. Facilities to update these specifications are included. The software provides the ability to override manufacturers' published performance specifications with actual equipment test data.
- Consideration of each stage of the pump and the ability to model fluid volume and physical properties as flow passes through each stage.
- A variety of multi-phase flow models to predict pressure losses in the tubing string.

The process of optimizing a centrifugal pump is a three step repetitive process (Illustration 1). The first step is to design the properly sized pump that fits the well characteristics. Once the pump is deployed, the performance must be monitored and the data collected for analysis. The third step, analysis, enables the operator to decide if the well was designed optimally. Furthermore, it provides information on pump wear and changes in the reservoir. That analysis allows the operator to "redesign" a new pump configuration to gain optimal performance again. The redesign phase allows the user to perform multiple design changes in a virtual fashion. This is an inexpensive way to experiment with different pump, motor, and cable configurations without actually deploying them downhole.

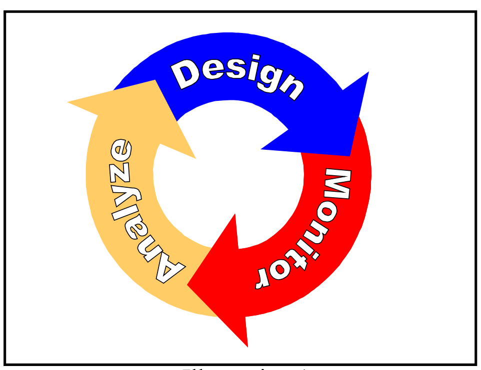

Illustration 1

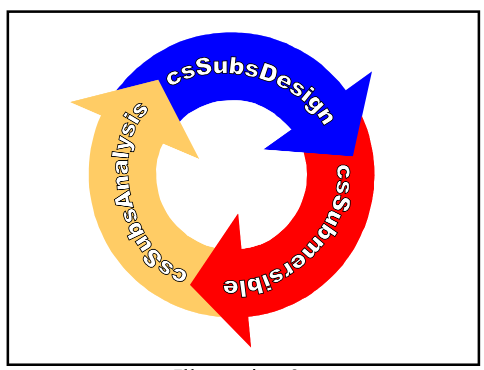

Illustration 2

The csSubs suite provides tools for all three steps in the optimization process (Illustration 2). The designing, monitoring, and analysis of the pump are handled by the three modules of the csSubs suite – csSubmersible for monitoring, csSubsDesign for design, and csSubsAnalysis for analysis.

With the proper well, fluid, and equipment data, a csSubsDesign user can predict the equilibrium point of the installed equipment. In doing so, the user can determine the suitability of a specific set of equipment to a given deployment.

Armed with csSubsDesign, an analyst can compare a variety of equipment under a range of operating conditions to determine the preferable (most efficient, most profitable, lowest cost, etc.) equipment for a specific well.

Afforded with csSubsAnalysis that can calculate electrical loss for motor cables, an analyst can predict lifting cost per volume. This cost can be used to compare the profitability of electrical centrifugal submersible pumping to that of other artificial lift techniques – within an operating unit.

Careful monitoring of installed centrifugal pumping equipment can provide a number of advantages – including:

- Identification of phenomena that create a system-equilibrium point outside the proper operating range of the pump.
- Changes in reservoir deliverability – (skin, declining reservoir pressure).
- Pump mechanical deterioration.
- Impact of changing fluids on pump operation.
- Changes in efficiency or lifting cost.

Through monitoring of the above criteria, proactive measures can be taken to lengthen pump run lives, optimize production, and better plan for replacement of deteriorating equipment.

Case Services Tools Provide Design And Analysis In An Easy-To-Use GUI

By putting the principles, calculations, and models discussed in the above text, csSubsDesign and csSubsAnalysis provide the detailed information needed for monitoring, analyzing, and designing submersible pumps. The information is presented in a clear and concise graphical user interface (Illustration 3 and 4) that displays the maximum information needed to efficiently optimize electrical submersible pumps.

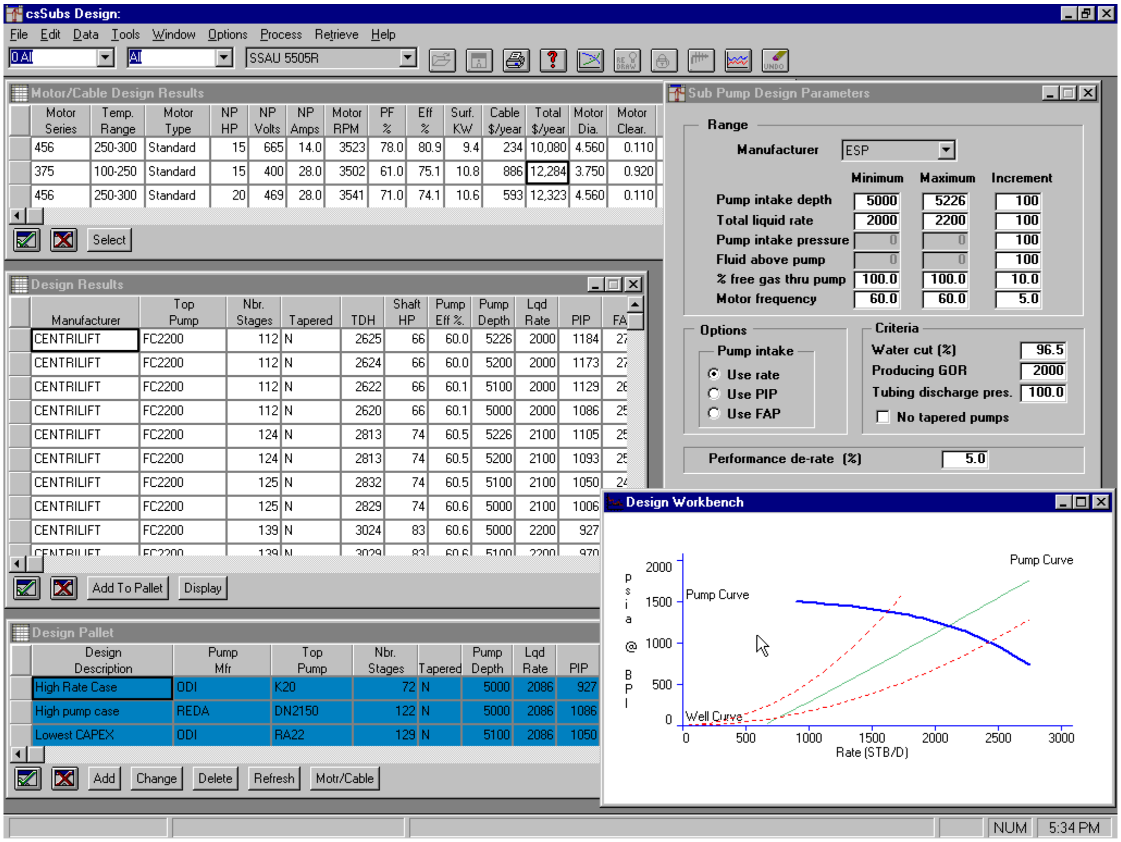

Illustration 3 - csSubsDesign

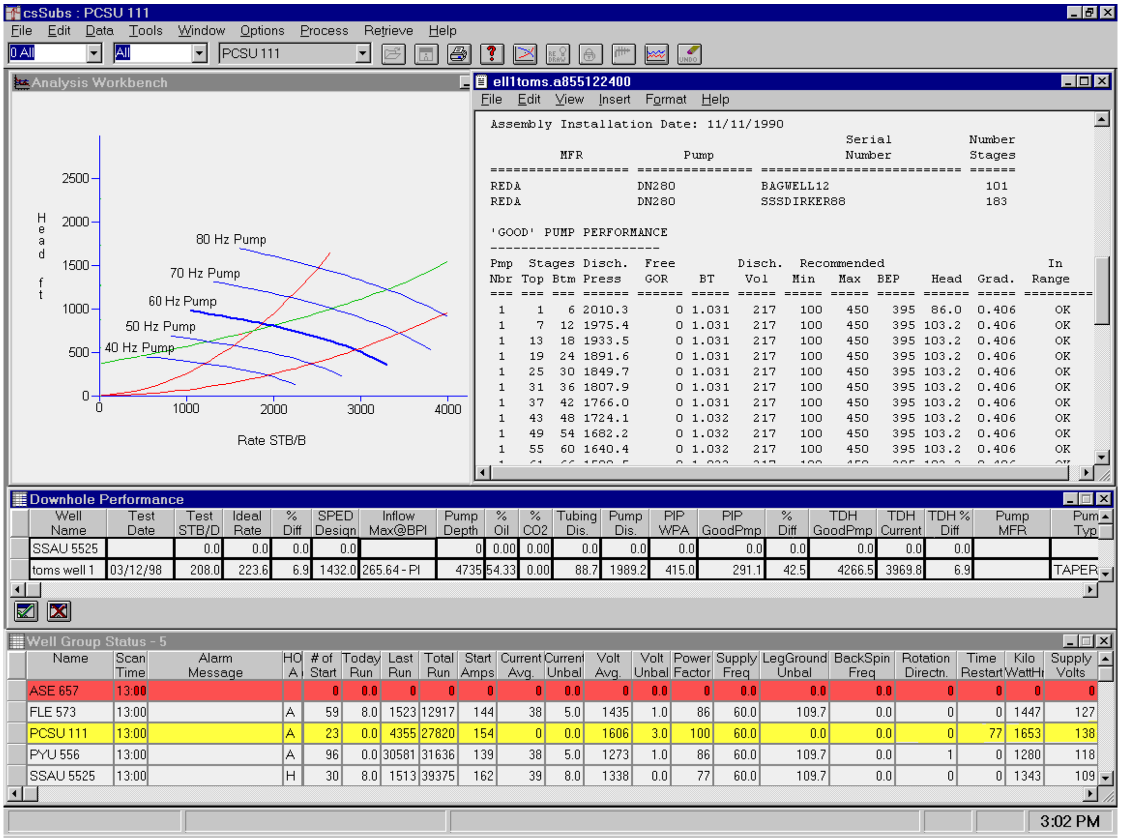

Illustration 4 - csSubsAnalysis

The combination of detailed technology and an easy-to-use interface makes the csSubs suite the right solution for optimization and maximum performance from ESPs.

As the leading provider of oil and gas production automation systems, **Case Services**, based in Houston, Texas, pioneered the market for single-source automation software for producing oil and gas fields. Major oil and gas companies use this software to run over 15,000 wells around the world.

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