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# Electric Submersible Pump (ESP) Selection Optimization: A Reservoir Engineering Outlook

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## Abstract

Recent advances in flow modelling and software development have revolutionized the modelling of well performance. The ESP design and selection software, however, is not up to speed in this regard.

The selection of an ESP for an oil well is often based on a given data set of well and formation data that is required to select the type of pump and number of stages. Very often though, the design engineer bases his calculation on the data provided at the time of the design and potential changes in design parameters. In reality, these parameters are not constant but rather dynamic and vary according to the reservoir performance, as a function of the rate of oil withdrawal and pressure maintenance capacity. This fact makes it very difficult to precisely account for such changes and in some cases, pumps do not make the intended design or fail prematurely within a short run time.

The study carried out in one of the ESP-lifted fields indicated an accelerated rate of changes in design parameters in some areas of the field due to the relative difference of fluid withdrawal to water injection as a function of rock quality in the area. The study indicated that this led to operating the ESP’s less efficiently, explaining the accelerated rate of pump failures in some areas.

This paper presents a new optimization scheme and field case studies that calculate potential changes in reservoir-related parameters of design. Studying the historical reservoir performance can help estimate the potential change of parameters in the study. This will enable optimization of ESP design with calculated risk based on projection of historical performance of the reservoir within the time period of study. The study indicated that optimization of pump design could prolong ESP life and reduce failure rate pertaining to reservoir performance.

## Background

### Pump performance

In well completion design, conventional and mechanistic models are used to match the flow capacity of producing string, often referred to as outflow performance, to the formation deliverability or the inflow performance. If the option of an ESP is to be considered for a particular well, the pump performance is then added to the calculation required. The characteristics of the pump performance is typically presented in the form of a “pump curve” a single graph that contains curves for the dynamic head, shaft horse power required, and efficiency.

The design of pump impeller and diffuser of a pump always determines the amount of head generated by each stage as a function of pump flow rate at certain speeds of the pump. Accordingly, pump curves may have different shapes that can be represented by empirical functions to be used in design calculations. Typically, centrifugal pumps have operating ranges, provided by manufacturers, within which pumps operate more efficiently. Fig. 1 shows a typical pump curve. The horizontal axis represents actual rate through the pump. Head, brake horse power, and efficiency are usually presented on the vertical axis per one stage. The peak in the efficiency curve is referred to as Best Efficiency Point “BEP.”

Pumps may have stable curves where the change of head as a function of flow rate is the same or increasing. On the other hand, if the change in head as a function of flow rate decreases at some point on the curve, the curve is classified as an unstable curve. The inflection point in the curve may complicate the solution of convergence due to the non-uniqueness of the solution point. In terms of pump performance, for a little change in head, it will result in a great loss of flow rate which favors the use of a stable curve if a potential change in head is expected. Figs. 2-5 show unstable and stable pump curves.

Pump curve is typically based on data generated in a test rig using water with a viscosity of 1 CP fluid. Conventional single-phase flow dynamics are inapplicable to model multi-phase centrifugal pumps. Very recently, several flow models were presented in literature that would give ESP manufacturers a tool to design the multi-phase flow through centrifugal pumps.

## Reservoir performance consideration

Reservoir performance is a measure of the reaction of the producing formation to the volume of withdrawal of oil and water and the subsequent change in its pressure. Reservoir surveillance of monitoring changes in formation pressure as a function of space and time, in addition to the percentage of water produced has been the practice to assess the reservoir performance.

As a reservoir matures, more fluid is produced and subsequently its pressure declines as a function of withdrawal of fluid production. At certain points of producing that reservoir, the producing energy or its ability to lift flow to surface dwindles. Hence, artificial lift becomes a necessity to lift wells by different means to offset that decline of energy. This complicates the reservoir performance monitoring, especially with full-field application of artificial lift. Localized accelerated changes in formation pressure and percentage of water may happen at different places and times in an artificially-lifted formation.

The introduction of downhole sensors and real-time monitoring has been a great tool to get an early alarm of changes in reservoir parameters in study. This helps the engineers monitor the well performance and take corrective action if required on a timely basis.

## ESP design consideration

If an ESP is to be part of well completion, it would require reliable data for the well and reservoir performance. Initial sizing of an ESP is done by determining the desired average flow rate through the pump and total dynamic head (TDH) required to make that rate. This depends primarily on the well inflow performance (productivity index and formation pressure) and fluid properties (mainly density and viscosity). 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. If either of these design parameters is inaccurate, then this could result in a misapplied pump that may operate outside its recommended operating range and result in premature failure and costly operation. Too often, data from other wells in the same producing formation is used assuming that wells in the same formation will have similar flow and fluid properties despite the fact that no two oil wells are alike.

In ESP design, it is crucial to operate the pump close to its best efficiency point. Therefore, one of the main pump selection criteria is the pump’s advertised BEP along with physical size. The head generated at the best efficiency point would determine the number of stages required to overcome that TDH by the system.

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. Changes do occur, and monitoring of the well using the surveillance 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 system 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 system curve. This would be an indication of pump performance deterioration.

## ESP design optimizations

Traditionally, 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. In the pump design process, an accurate model of the well’s inflow performance must be developed. Hence, classical optimization process is applied to match the system curve, or the outflow performance of the tubing, to the pump curve at its BEP. Fig. 6 shows pump and system head curves match.

With the emerging design software that has a data base of available motors and its power factor efficiencies, the optimization process has advanced a step further to optimize power requirements and consumption. Classical optimization processes, however, use initial and potential changes in parameters of the ESP design. If the reservoir performance reflect otherwise then not much can be done but to wait until the pump fails, due to operating out of its design, and a workover rig is to pull that pump from the hole.

## Pump Selection

The optimization scheme to account for reservoir parameter changes, involve the selection of pump curve type that would have less impact with the potential changes in these parameters. In addition, the number of stages is selected to have enough to absorb the total change in TDH. Stable curves with steep slope are assumed to be more suitable for areas with high potential changes in factors that change the TDH.

## Field Application

To quantify the reservoir performance impact on ESP performance, and evaluate potential ESP design optimization, the TDH was calculated as a function of time and space over an appreciable time frame. The study period covered several ESP installations and replacements in some of the wells in the reservoir. The changes of the TDH in each well were calculated from the changes in the design parameters pertaining well/reservoir performance. These include reservoir pressure, water cut and well-productivity index. The changes in these parameters were translated into head. That is to assess the impact of changing the TDH on ESP performance by looking at how much head increase will be seen on each stage before the pump operates outside its recommended operating range. This technique is very essential to determine areas of accelerated changes in the parameters to study and highlight hot spots in the reservoir that warrants a special design of ESP.

The calculations made indicated variation of the change of TDH in some areas of the field which explained the short run life that were run in these wells. Shown in chart 1 is the TDH over a long period of time calculated for all the wells in the field. Negative values represent areas with strong pressure maintenance due to injection. Some wells indicated an accelerated rate of change of TDH with cutting more water. Fig 7 shows a well with three installations of the same ESP type that fails as a result of increased TDH due to the decrease of formation pressure, increase of water cut or both.

ESP run life statistics in the field support the fact of reduced run life as a result of accelerated changes in the design parameters in some areas of the field. Fig. 8 shows the survival analysis that indicated two distractive trends; the majority of ESPs were 675 days of operation. The short life wells were 365 days of operation on the curve.

## Conclusions

- Studying reservoir performance is essential to understand the specifics of the flow dynamics in the area.
- Reservoir and ESP performances have mutual effect.
- ESP designers should consider the potential changes in ESP design parameters and consequences of reservoir performance effect.
- Using proper tools and software could help quantifty potential change in design parameters that would enable better ESP design optimization.

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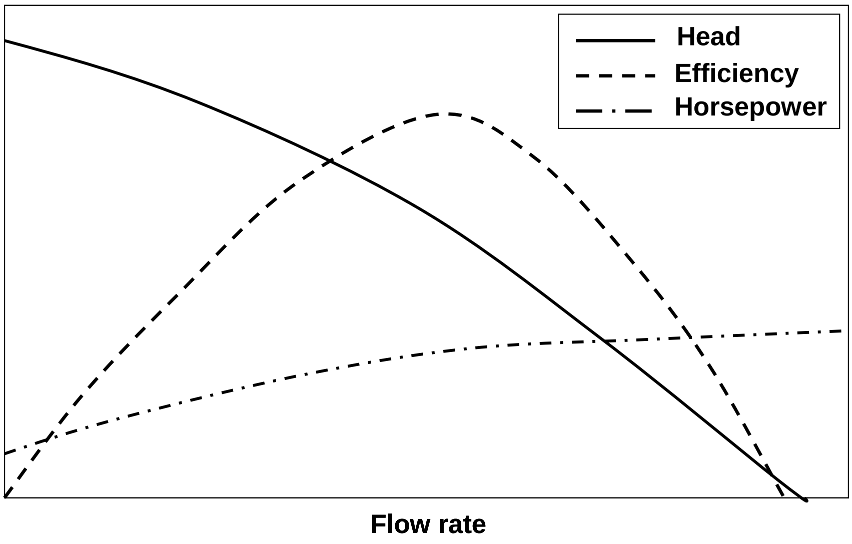

Fig. 1 Typical pump curve

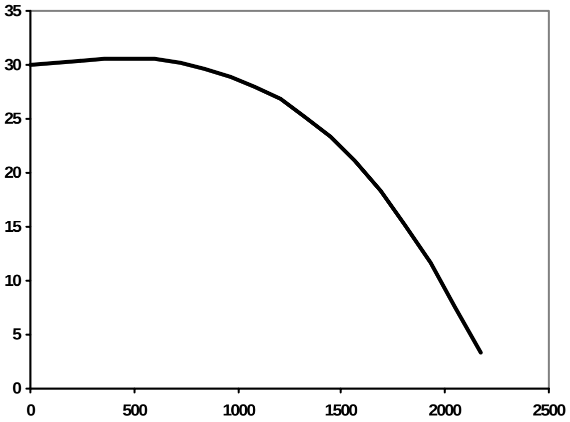

Fig. 2 Unstable pump curve

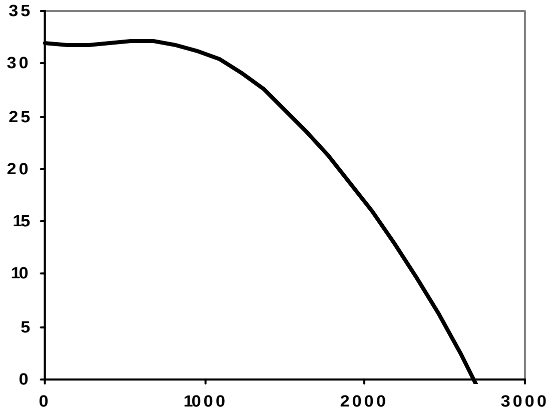

Fig. 3 Unstable pump curve

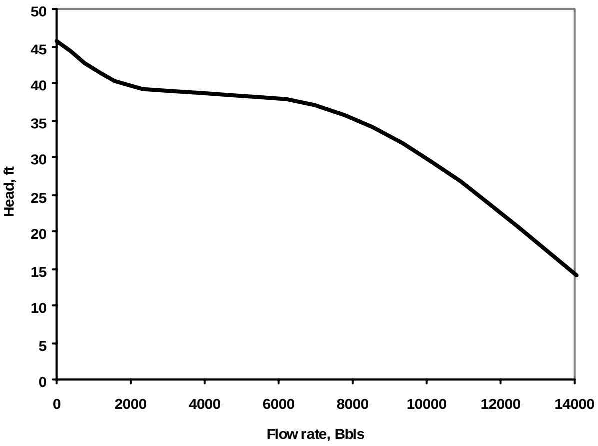

Fig. 4 Unstable pump curve

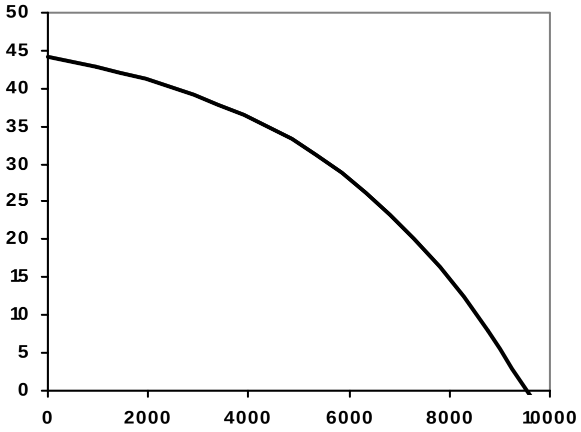

Fig. 5 Stable pump curve

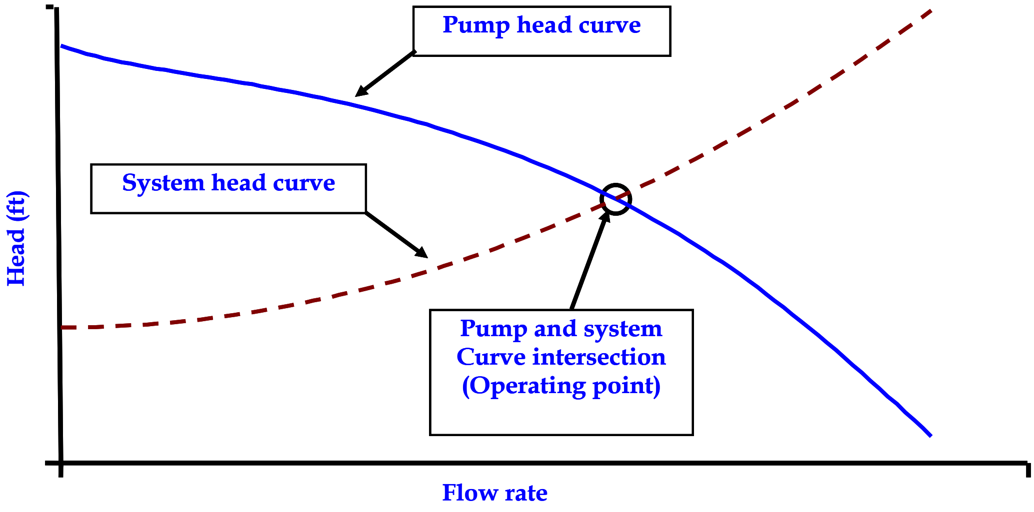

Fig. 6 Pump and system head curves

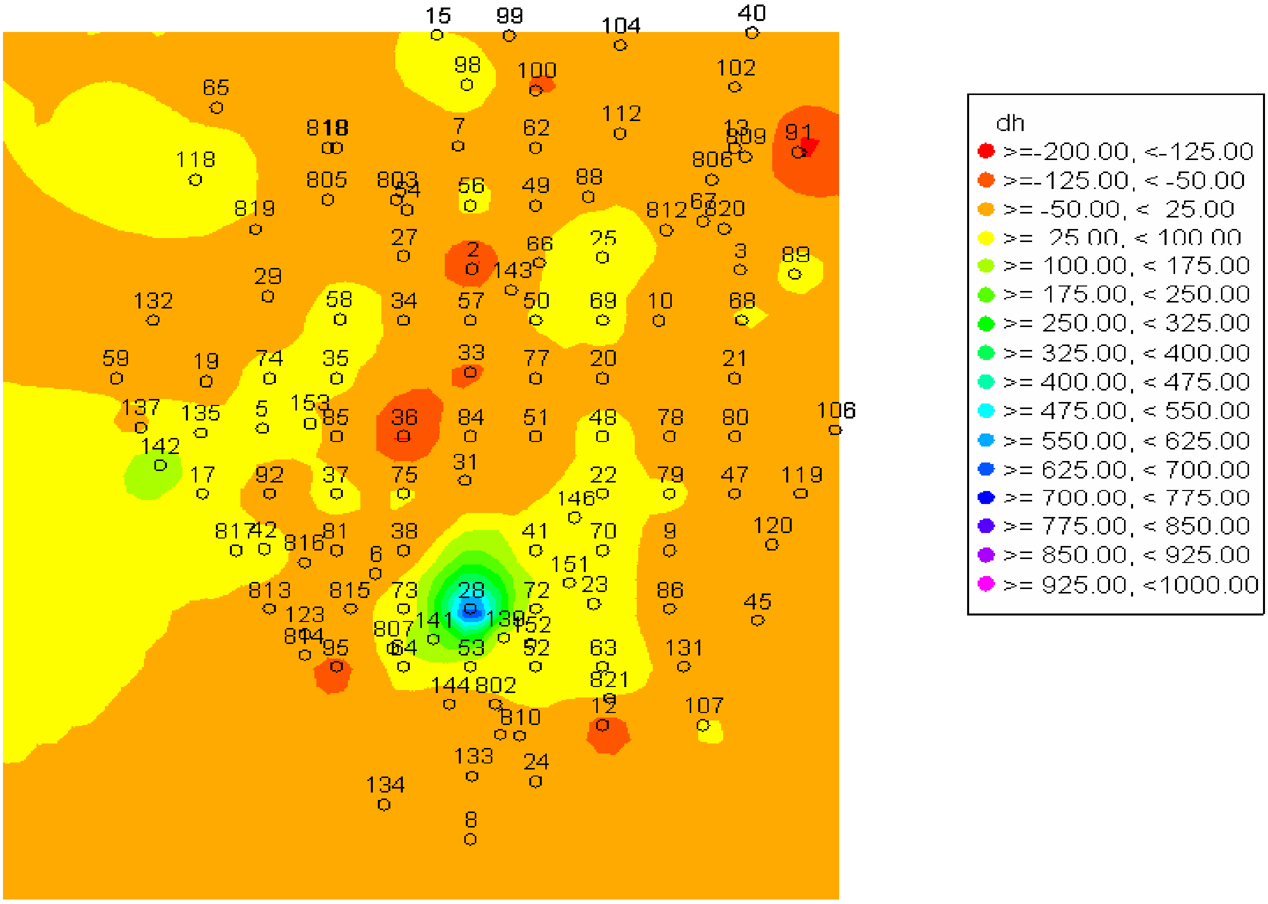

Chart 1, TDH map

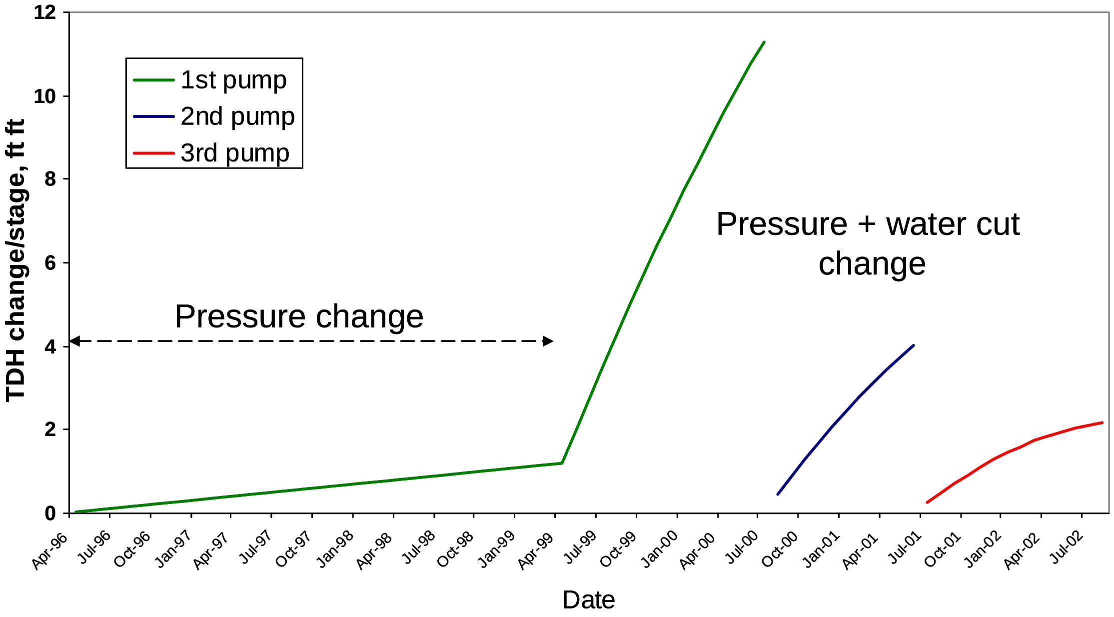

Fig. 7 TDH during three ESP's replacements.

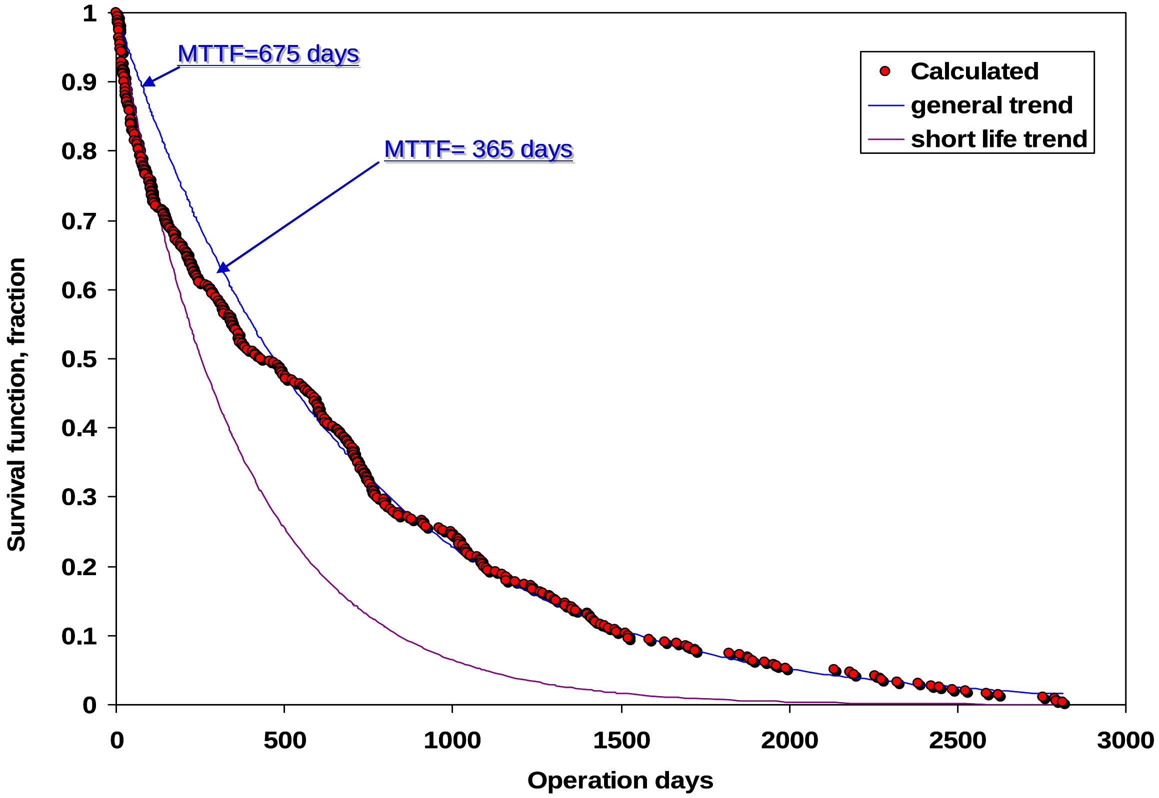

Fig. 8 ESP run life trend in the field of study