ANALYZING THE DESIGN OF SUBMERSIBLE LIFTED DEVIATED OIL WELLS

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

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IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
PETROLEUM AND NATURAL GAS ENGINEERING

JANUARY 2005

Approval of the Graduate School of Natural and Applied Sciences.

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ABSTRACT

ANALYZING THE DESIGN OF SUBMERSIBLE LIFTED DEVIATED OIL WELLS

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January 2005, 188 pages

Electrical Submersible Pumping (ESP) is a well known artificial lift technique in reservoirs having high-water cut and low gas-oil ratio. It is known as an effective and economical method of producing large volumes of fluid under different well conditions. ESP equipments are capable of producing in a range of 200 b/d to 60.000 b/d. A case study was done, by designing 10 deviated or horizontal wells selected from the Y-oilfield in Western Siberia. SubPUMP software developed by IHS Energy is used for designing the ESP systems of these wells. These 10 wells will be working with variable speed drives. After selecting the available equipment from the inventory, the best running frequencies are selected for these wells. Evaluations of the designs are made from the pump performance graphs of each well. The pumps should work within their optimum efficiency ranges. These ranges can be seen from the pump performance curves. If the designs made are not within these efficiency ranges, designs should be evaluated and selecting new equipment should be should be an option. Because working outside the optimum efficiency ranges will decrease the production, shorten the runlifes of the pumps and the production will not be stable.

Keywords: Electrical submersible pumps, ESP, deviated wells, horizontal wells variable speed drive, VSD, analyzing, production optimization, artificial lift.

ÖZ

DALGIÇ POMPALI YÖNLÜ PETROL KUYULARINDA DİZAYN ANALİZİ

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Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü
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Ocak 2005, 188 sayfa

Dalgıç pompalarla üretim, yüksek su oranlı ve düşük gaz oranlı petrol kuyularında sık kullanılan bir yapay üretim metodudur. Bu metod çeşitli kuyu şartlarında yüksek hacimli akışkan üretimi için ekonomik ve etkili bir metottur. Dalgıç pompa sistemleri 200 varil/gün ile 60.000 varil/gün arasında üretim kapasitesine sahiptir. Batı Sibirya Y – petrol sahasından seçilen 10 yönlü kuyu ile bir inceleme çalışması yapılmıştır. IHS Energy tarafından geliştirilen SubPUMP yazılımı dalgıç pompa sistemi tasarımında kullanılmıştır. Bu 10 kuyu Değişken Hız Sürücüleri ile çalışacaktır. Varolan stoktan uygun ekipman seçildikten sonra, bu kuyular için en uygun çalışma frekansı seçilmiştir. Pompa performans grafiklerinden her kuyu için tasarımların analizi yapılmıştır. Şayet yapılan dizaynlar optimum verimlilik aralığınmda değil ise yeniden değerlendirilmeli ve yeni ekipman seçimi düşünülmelidir. Çünkü optimum verimlilik aralığı dışında çalışan pompaların üretimi azalacak, çalışma ömürleri düşecek ve üretim kararlı olmayacaktır.

Anahtar Kelimeler: Dalgıç pompa, yönlü kuyu, yapay üretim, değişken hız sürücüsü, üretim optimizasyonu.

To My Family

ACKNOWLEDGMENTS

I am deeply grateful to my supervisor Prof. Dr. Suat Bağcı for his valuable comments, sincere guidance and encouragement through this study.

Sincere thanks to İnci Yıldız Kahya, who has always believed in me and supported me in every step of this study; and to my family for their endless support and understanding.

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NOMENCLATURE

SYMBOL	DESCRIPTION	UNIT
$Amps_{motor}$	Motor amps	amps
Angle	Wellbore angle for the section	degrees
BP_{head}	Back pressure head	ft
CG CD	Geometric factors	
Design Hz	Design frequency entered by user	Hz
E	Efficiency of natural gas separation fraction	
F_o	Oil fraction of total fluid	
FOP	Fluid over pump as the vertical distance from the pump intake to the gas-fluid interface in the casing	ft
F_w	Water fraction of fluid or water cut	
g	Gravitational acceleration	ft/sec^2
$_g r$	Density of gas phase	lb/ft^3
g_o, g_g, g_l	Oil gas and liquid gradients	psi/ft
H	Height of the fluid column above the point	ft.
$HP_{motor\ derated}$	Motor horsepower derated for temperature	hp
$HP_{motor\ inflated}$	Motor horsepower inflated due to wellbore temperature effects at 60 Hz	hp
$Hp_{pump\ 60}$	Pump horsepower at 60 Hz	hp
$HP_{pump\ actual}$	Actual Pump horsepower adjusted for motor slip	hp
$HP_{pump\ Hz}$	Required pump horsepower at the design frequency	hp
$HP_{req.\ at\ design\ Hz}$	Required motor horsepower at design Hz	hp
$Hp_{seal\ 60}$	Seal assembly horsepower at 60 Hz	hp
$HP_{GasSepHz}$	Gas separator HP at design frequency	hp
$HP_{motor\ 60\ Hz}$	Motor horsepower at 60 Hz	hp
$HPp_{ump\ Hz}$	Required pump horsepower at design Hz	hp

SYMBOL	DESCRIPTION	UNIT
J	Productivity Index	blpd/psi
J_{init}	Initial value of the productivity index	blpd/psi
$_l r$	Density of liquid phase	lb/ft^3
MAF $_{coeff.}$	Motor amp factor from coefficients	
MLF_{60Hz}	Motor load factor at 60 Hz	
MSF	Motor service factor correction for wellbore temperature	
Np Amps	Name plate amps from database	amps
NPHP	Motor name plate horsepower	hp
$NPHP_{motor}$	Name plate horsepower of motor from database	hp
$OMLF_{Design\ Hz}$	Operating motor load factor at design Hz	
P_b	Bubble point pressure	psi
P_{csg}	Surface casing pressure	psia
P_{dp}	Pump discharge pressure	psi
PDP_{head}	Pump discharge pressure head	ft
PI	Productivity Index	blpd/psi
P_{ip}	Pump intake pressure	psia
P_{ip}	Pump intake pressure	psi
PIP_{head}:	Pump intake pressure head	ft
P_r	Static reservoir pressure	psi
Pwf	Bottom-hole flwoing pressure	psig
P_{wfg}	Flowing bottom hole pressure on composite IPR curve at Qomax rate	psi
P_{wh}	Wellhead or separator pressure	psi
Q_b	Flowrate at bubble point	blpd
Q_{omax}	Maximum oil flowrate	blpd
Q_{tmax}	Maximum liquid flowrate on composite IPR where water cut is not 100%	blpd
RPM $_{design\ Hz}$	Motor RPM corrected to design Hz	RPM
RPM $_{motor\ 60\ HZ}$	Motor RPM from motor coefficients at 60 Hz	RPM
RPM $_{w/slip}$	Motor RPM loss caused by motor slip	RPM

SYMBOL	DESCRIPTION	UNIT
$RPM_{pump\ w/slip}$	RPM of pump under load adjusted for motor slip	
s	Surface tension	lb/sec^2
${}_{sl}v$	Superficial velocity of liquid phase	ft/sec
Test P	Flowing bottom hole pressure of test point	psi
TestQ	Flowrate of test point	blpd
TVD_{fluid}	Vertical depth of gas-fluid contact	ft
TVD_{pump}	Vertical depth of pump intake	ft
$TVD_{top\ perf}$	Vertical depth of top perforation	ft
$V_{motor\ @\ design\ Hz}$	Required motor voltage @ design Hz	volts
$V_{motor\ 60\ Hz}$	Motor voltage at Hz from coefficients	volts
$V_{motor\ at\ design\ Hz}$	Required motor voltage at design Hz	volts
ΔMD	Change in MD for the section	ft
ΔTVD	Change in TVD for the section.	ft
γ	Gradient of the fluid column	psi/ft
${}_{\infty}v$	Terminal bubble rise velocity	ft/sec

CHAPTER 1

INTRODUCTION

The driving force, which displaces oil from the reservoir, comes from the natural energy of the compressed fluids stored in the reservoir. The energy that actually causes the well to produce is a result of the reduction in pressure between the reservoir an the well bore. If the pressure reduction between the reservoir and the surface producing facilities is great enough, the well will flow naturally to the surface using only the natural energy supplied by the reservoir [1].

When the natural energy associated with oil will not produce a differential pressure differential between reservoir and wellbore sufficient to lift reservoir fluids to the surface and in to surface facilities, or will not drive it into the surface in sufficient volume, the reservoir energy must be supplemented by some form of artificial lift.

Electric Submersible Pump (ESP) is a well known artificial lift technique in reservoirs having high-water cut and low gas-oil ratio. It is known as an effective and economical method of producing large volumes of fluid under different well conditions. ESP equipments are capable of producing in a range of 200 b/d to 60.000 b/d.

ESP systems operate on a centrifugal pump concept whereby the fluid pressure increases from a rotational force of acceleration caused by the vanes in the pump accelerating the fluid in each pump stage. Unlike a positive displacement pump, a centrifugal pump can have fluid flowing though the pump even if the pump is not in operation. For this reason, centrifugal pumps should not be thought of as a mechanism to increase the pressure of the fluid between the inlet and the discharge point. The flowrate of fluid through the pump is in direct relationship to the pressure difference between the intake point and the discharge point regardless of whether the pump is operating or not. Instead the contribution of a centrifugal pump is measured as the amount of head that the pump can exert on a fluid pumped at a given rate and RPM. As the rate increases, the pump's head capacity decreases and vice versa.

In the absence of free gas each stage of the pump handles a volume of fluid and produces a proportionate amount of head. The head is additive through all of the stages of the pump. More stages added to a pump design will not increase the fluid volume, but will only increase the amount of head the pump is capable of producing. As more stages are added to the pump, the required horsepower to drive the pump is also increased. This will require a motor capable of delivering a sufficient amount of horsepower to drive the pump in an efficient manner.

Designing an ESP system must make use of many interrelated components such as pump, motor, gas separator, tubing, reservoir, etc to arrive an optimum design. For example, the length of the tubing and flowrate will determine the pump depth and the pump discharge pressure. The flowing bottom hole pressure and pump depth will determine the flowrate and pump intake pressure. The pump intake pressure and discharge pressure will determine the amount of total dynamic head necessary for the pump design. This will determine the horsepower and motor requirements. The required motor will lastly need a cable capable of delivering sufficient power to start the motor and run it efficiently with minimal losses [2].

In this study, 10 horizontal or deviated wells were selected from the Y-oilfield in Western Siberia. SubPUMP software developed by IHS Energy is used for designing the ESP systems of these wells. These 10 wells will be running on Variable Speed Drives. After selecting the equipment the best working frequencies are selected for these wells, and evaluations of the designs are made from the pump performance graphs of each well.

CHAPTER 2

ELECTRICAL SUBMERSIBLE PUMPS

2.1 ESP SYSTEM

2.1.1 Typical ESP System

The submersible pump consists of an electric motor attached to a pump and protector with other key component parts as described in this section which are run into the well on production tubing. Figure 2.1 shows a typical ESP installation.

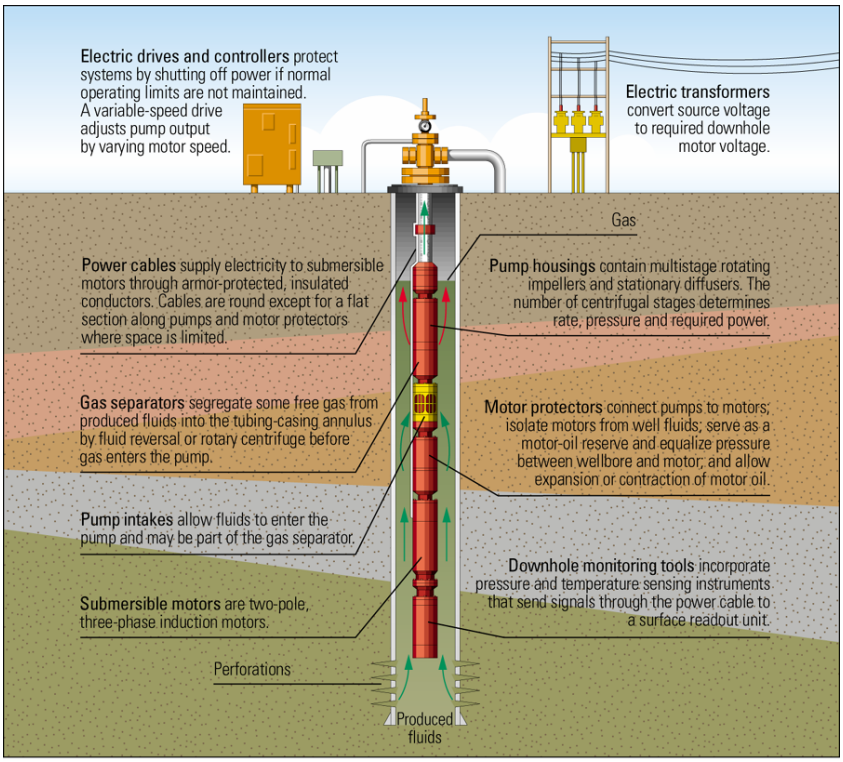


Figure 2.1 A Typical Submersible Pump Installation [3]

2.1.2 Submersible Electric Motor

The motor is a three phase, squirrel cage, two pole induction design. Because of the way the stator is wound, the three phase power establishes a two pole magnetic field within the stator. Figure 2.2 shows an electric motor. The stator is the core or electrical field of the motor. The stator is composed of the housing material for a desired diameter, the stator core, and the stator windings [3].

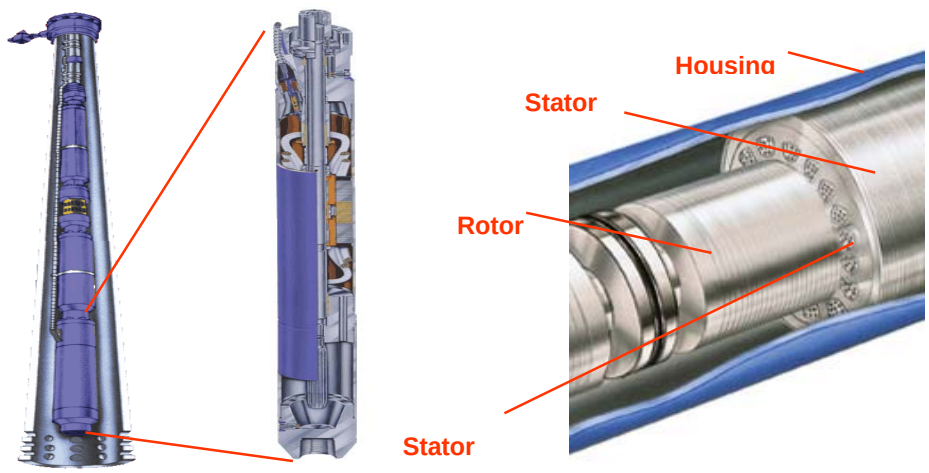


Figure 2.2 Electric Motor [3]

2.1.3 The Protector

The protector is the piece of equipment that is typically placed above the motor. Figure 2.3 shows a typical protector [3].

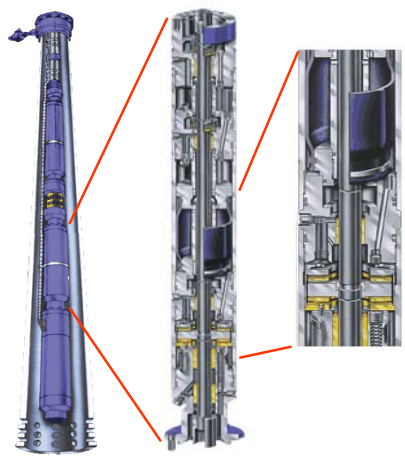


Figure 2.3 The Protector [3]

The primary functions of the protector are:

- To couple the motor to the pump, to transmit the torque to rotate through the shaft,
- To act as a reservoir chamber for fluctuations in cycling the equipment for oil expansion,
- To provide the thrust bearing to carry the thrust load of the pump,
- To act as a seal chamber to prevent the migration of well fluids from entering the motor,
- To equalizes pressures between the motor and the wellbore.

2.1.4 Gas Separator

In some applications, there may be gas produced along with the oil and water liquids. If gas is present, then a gas separator will be installed and attached to the pump

suction to assist in eliminating some of the gas that might be produced through the pump. In figure 2.4 a gas separator can be seen [3].

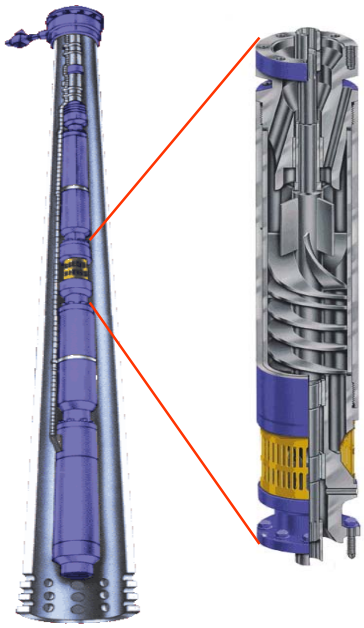


Figure 2.4 Gas Separator [3]

There are several methods of separating the gas from solution. Two different types of gas separators are shown in figure 2.5.

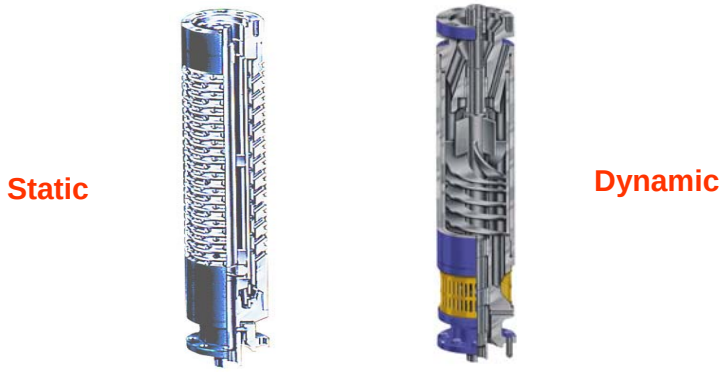


Figure 2.5 Types of Gas Separators [3]

Static Type - Allows the well fluid to enter past a multitude of passages where reversals in flow direction occur, creating a pressure drop, and separating gas from solution to escape to the annulus. Since this type of gas separator does no real "work" on the fluid, it is also called a "static" gas separator.

Dynamic Type - Allows entry of fluids and gas at the base of the separator into a rotating centrifuge with and inducer and straightening vanes. Heavier fluids move to the outside and the gas to the inside. Gas passes through a crossover and up the annulus.

Original gas separator designs were based on increasing gas separation by forcing the fluid flow to reverse in the wellbore. This is where the name of this type of gas separator, reverse flow, comes from. Dynamic gas separators actually impart energy to the fluid in order to get the vapor to separate from the liquid. The original gas separator was called a KGS (short for either Kinetic Gas Separator or Kobylinski Gas Separator). This design uses an inducer to increase the pressure of the fluid and a centrifuge to separate the vapor and liquid. This design could likewise be called a centrifugal gas separator.

The rotary gas separator design works in a similar fashion to a centrifuge. The centrifuge "paddles" spinning at 3500 rpm cause the heavier fluids to be forced to the outside, through the crossover and up into the pump, while the lighter fluid (vapor) stays toward the center, and exits through the crossover and discharge ports back into the well [3].

2.1.5 Centrifugal Pumps

The term “centrifugal pump” has been used to describe a wide variety of pumping applications and designs throughout the years.

- A Centrifugal Pump is a machine that moves fluid by spinning it with a rotating impeller inside a diffuser that has a central inlet and a tangential outlet.
- The path of the fluid is an increasing spiral from the inlet at the center to the outlet tangent to the diffuser.
- The pressure (head) develops against the inside wall of the diffuser because the curved wall forces fluid to move in a circular path rather than by converting velocity head to (pressure) head.

The centrifugal pump is a multistage pump, containing a selected number (application dependent) of impellers equipped with vanes, inside a closely fitted diffuser, located in series along an axial shaft, driven by the electrical motor. Figure 2.6 shows the pump stages.

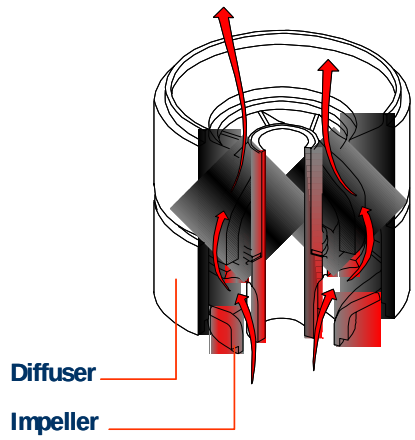


Figure 2.6 Pump Stages [3]

A centrifugal pump creates pressure by the rotation of a series of vanes in an impeller. The motion of the impeller forms a partial vacuum at the suction end of the impeller. The impeller's job is to transfer energy by rotation to the liquid passing through it, thus raising the kinetic energy. The diffuser section then converts this energy to potential energy, raising the discharge pressure. Outside forces, such as the atmospheric pressure or weight of a column of liquids, push fluid into the impeller eye and out to the periphery of the impeller. From there, the rotation of the high-speed impeller throws the liquid into the diffuser. Each "stage" consists of an impeller and a diffuser. Again, the impeller takes the fluid and imparts kinetic energy to it. The diffuser converts this kinetic energy into potential energy (head).

2.1.6 Pump Performance Curve

These motors normally operate at 3,500 rpm on a 60-cycle power supply or 2,900 rpm on a 50-cycle power supply. Figure 2.7 shows a typical pump performance curve [4].

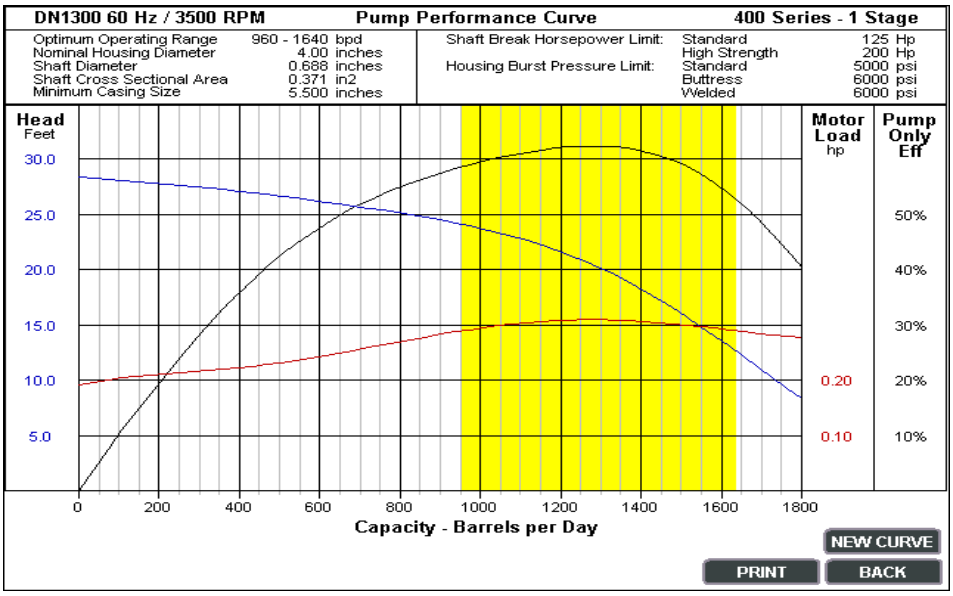


Figure 2.7 Pump Performance Curve [3]

2.1.7 Cable Section

Electrical power cable is used to transmit the power from the surface to the submersible motor. Power Cable consists of three copper conductor wires extending from the top of the motor flat cable lead to the wellhead. The size of the cable selected is based on amperage and voltage drop. Bottom hole temperature is critical for the selection of cable. The electrical cable has been refined over the years to be used specifically for oil well applications. In figure 2.8 the components of a cable can be seen [3].

The main components of the power cable include:

<u>The conductor</u>: Transmits the electricity.

<u>Insulation material</u>: Protects and covers the conductor wire.

Barrier Jacket: Protects and covers the insulation.

Jacket Material: Rubber compound designed for temperature, chemical, and gas considerations.

The exterior armor: The outer shield that holds it all together.

Figure 2.8 Cable Components [3]

2.1.8 Power Cable Connection

Electric power is conducted to the assembly through an electrical cable attached to the tubing. Figure 2.9 shows power cable and connection of the cable.

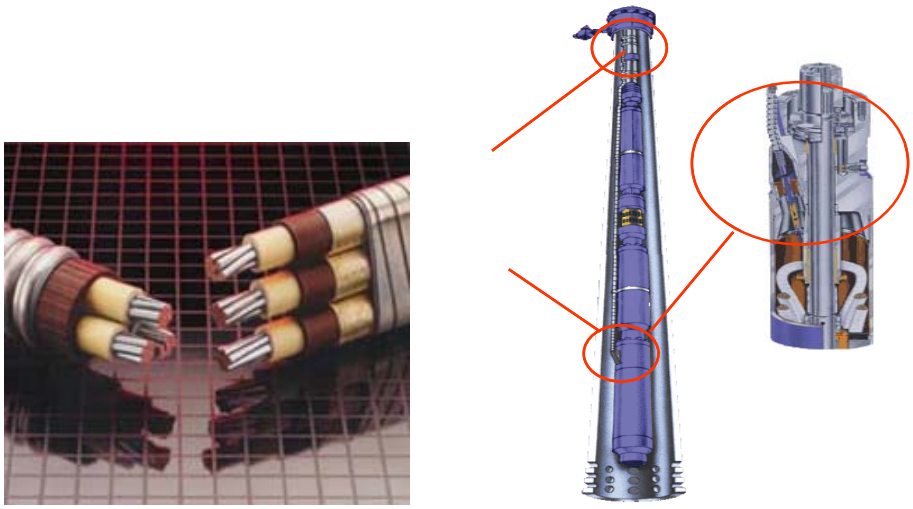


Figure 2.9 Power Cable [3]

2.2 SURFACE EQUIPMENT SECTION

2.2.1 Wellhead

The wellhead is the equipment that is installed at the surface of the wellbore. Figure 2.10 shows a wellhead. Its purpose is to suspend the tubing string in the well, and to monitor and control high pressures conditions often present within the well [3].

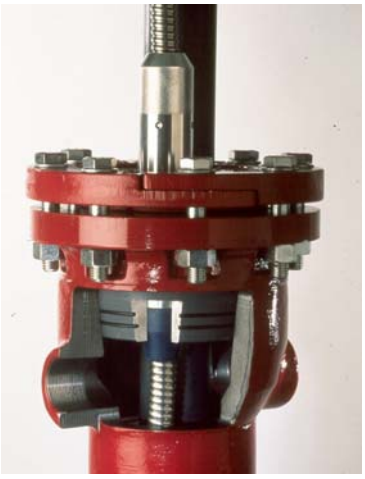


Figure 2.10 Wellhead [3]

2.2.2 Transformer

A transformer is used to power the surface equipment and in turn, sends a signal through to the power cable. The transformer sends the correct voltage to the switchboard for designed surface voltage for the proper motor operation. In figure 2.11 a transformer can be seen. This is based on power rating in KVA. Transformers can be either single phase or three phase. Normally when using single phase transformers for three phase power, three individual transformers are connected together, in various configurations [3].

2.2.3 Surface Cable

The Surface Cable is the cable that connects from the junction box to the motor control panel. The Surface Cable is the cable that connects from the motor control panel to the secondary side of the transformer. There is a maximum length stipulation for each section of surface cable [3].

Figure 2.11 Transformer [3]

2.2.4 Junction Box

It provides a connection point for the surface cable from the motor control panel to the power cable in the wellbore. Allows for any gas to vent that may have migrated through to the power cable. Provides easy accessible test point for electrically checking downhole equipment. Figure 2.12 shows the junction box [3].

Figure 2.12 Junction Box [3]

2.2.5 Motor Controller/Switchboard

The controller is a device that can be used as a soft-start for the motor with overload and underload protection capabilities. Figure 2.13 shows the switchboard. The controller also provides the capability to monitor the REDA Production system with the use of a recording instrument. The two types of controllers offered are electro-mechanical relays or solid-state control circuitry [3].

Figure 2.13 Switchboard [3]

2.2.6 Variable Speed Controller

The variable speed controller allows for flexibility of the downhole system for flow control capabilities. It provides a constant ratio of between voltage and frequency for proper operation. Figure 2.14 shows the variable speed drive [3].

Figure 2.14 Variable Speed Controller [3]

2.3 ADDITIONAL DOWNHOLE EQUIPMENT/ACCESSORIES

Additional equipment typically used in a standard downhole production system string might include:

- Downhole pressure and temperature measuring equipment (DME)
- Check and Bleeder valves
- Drain valves
- Downhole packers
- Cable penetrators
- Cable protectors/bands
- Injection lines
- Y-Tools

2.4 APPLICATIONS OF ESP SYSTEMS

Electrical submersible pumping is usually used for higher volumes of production rates. Electrical submersible pumps are usually used in applications where production rates are greater than 1,000 bbl/day. Standard applications insure that the pump is set above the perforations, such that there will be ample cooling provided by the fluid velocity of the producing fluid level as it passes across the motor to provide cooling [3].

2.4.1 Why ESPs are used for high lifting volumes

More horsepower can be delivered to the pump in oil well casing than with other artificial lift methods. Centrifugal pumps are capable of producing higher rates compared to positive displacement types pump in oil well casing applications. Other artificial lift methods should be considered for lower production rates, as these are usually more economical [3].

2.4.2 Advantages of ESP Systems

The main advantage of the electrical submersible pump is the flexibility of the system.

- Can be used at low bottom hole pressures.
- Can operate reliably in deviated in wells.
- Can be used effectively for offshore applications.
- Operate under extreme conditions such as higher bottom hole temperate applications with the use of alternative materials.
- Can be utilized in a corrosive and scale conditions with alternative materials.

2.4.3 Disadvantages of ESP Systems

The main disadvantages for electrical submergible pump units relate to temperature conditions.

- Cable temperature limits must be identified and reviewed.
- Available power for required horsepower must be available.
- Usage of switchboards at constant speed limits the flexibility of the production rates.
- Higher gas content can limit system capabilities.
- High solids may cause rapid wear and premature failure.

2.5 LITERATURE SURVEY

In 1986, J.F. Lea and K.E. Brown have studied on production optimization using a computerized well model. Many oil and gas wells may be producing at races which appear to be optimum but which actually contain unnecessary restrictions to flow. These wells can be analyzed using modelling techniques to evaluate all components of a producing well system. Often this procedure will identify possible modifications

in the well which if made will result in larger flow rates. This method described is often referred to as Nodal Analysis. All components starting at the static reservoir pressure and ending at the separator are evaluated if present. This may include inflow performance, flow across the completion, flow up the tubing string including any down-hole restrictions, safety valves, flow across the surface choke (if applicable) and flow through horizontal flow lines and into the separation facilities.

The objectives of well analysis are as follows:

1. To determine the flow rate at which a well will produce with a given wellbore geometry and completion (first by natural flow).
2. To determine under what flow conditions a well will cease to produce. This can be related to time as the reservoir depletes.
3. To select the most economical time for the installation of artificial lift and to assist in the selection of the best artificial lift method.
4. To optimize the well conditions and geometry system in order to most economically produce the objective flow rate.
5. To analyze each component in the well system to determine if it is restricting the flow rate unnecessarily when compared to the flow capacities of the other system components.
6. Overall, this permits quick recognition by the operator's management and engineering staff of ways and means to increase production rates. This is a very important feature of being able to graphically display the wells performance with "production optimization" or "Nodal Analysis Techniques."

There are numerous oil and gas wells around the world that have not been optimized to achieve an objective rate in an efficient manner. In fact, many may have been routinely completed in a manner such that their maximum potential rate cannot be achieved. Also, many of the wells placed on artificial lift are not achieving the efficiency that may be possible.

The production optimization of oil and gas wells using computerized well models has contributed to improved completion techniques, better efficiency, and higher production with many wells. [19]

Well analysis is an excellent method for indicating how to obtain the objective flow rate on both oil and gas wells. A common comment is "we just don't have enough

data to use this analysis." This is true in some cases, but it is amazing the improvements in wells that have been made beginning with very little data. Analysis has also prompted the obtaining of additional data by properly testing numerous wells.

Another concern is that there is too much error involved in the various multiphase flow tubing or flowline correlations, completion formulas, etc., to obtain meaningful results. Because of these possible errors, sometimes it is difficult to get a predictive well analysis plot to show an intersection at the exact rate as the well is currently being produced. However, even if current production cannot be matched exactly, the analysis can show a percentage increase in production with a change, for instance, in wellhead pressure or tubing size. Often these predicted possible increases are fairly accurate even without an exact match to existing flow rates. [19]

Dan McLean, Roger Clay and Wayne Gould made a study on Production Management of Electric Submersible Pumps Using Expert System Technology in 1998. Management of electric submersible pumps (ESP) at wellsites can be improved using expert system technology to combine real time sensor information with production engineering knowledge rules. When abnormal conditions exist on an ESP well it is not always apparent that there is a problem until significant production loss and/or the results of pump damage become apparent. By applying expert system technology and elements of artificial intelligence, visualization of well performance in relation to the pump manufacturers' operating limits can be presented to operations personnel in real time. The well performance can then be maximized once the operating constraints are known and algorithms to optimize production can logically follow. The expert application described in this study demonstrates this ability and can be extended easily to multiple well sites. The primary objective is to reduce operating and maintenance costs by providing virtual operations assistance so that new wells can be operated and optimized using existing operations personnel.

A submersible pumping system can be analyzed on the basis of a single point stable test when the pump intake pressure and the annulus gas rate are known. The results will be tubing flow performance, an estimate of pump discharge pressure, pump performance from suction to discharge, and a single point on the top of perforations well inflow capability curve for the operating tubing head pressure when the test was

obtained. By applying known characteristics for the producing zone, the well inflow capability at the top of the perforations depth can be established for the entire range of producing pressures between static reservoir pressure and zero. Pressure traverse procedures can be applied to transpose the well inflow characteristics to the pump intake depth, and the well capability at pump intake depth is established. Data provided by the pump manufacturers is overlaid on the pump intake depth well capability data to provide a bench mark data set of operating constraints associated with the well and the installed equipment for the current test.

Artificial lift using electric submersible pumps continues to gain popularity, however the impact of non-flowing conditions is a source of production loss and equipment damage that is difficult to detect and rationalize. Combining the knowledge of operating experience, empirical relationships, and specific oil properties into a single management software tool can have enormous potential benefit to exploration and production operators. [20]

In 2001, S.J. Sawaryn and E. Ziegel have investigated statistical assessment and management of uncertainty in the number of electric-submersible pump failures in a field. Successful management of a population of Electric Submersible Pumps (ESPs) requires an accurate estimate of the expected number of failures as a function of time plus a determination of the associated uncertainty. Knowledge of the uncertainty is required for an effective risk assessment to be made of workover strategies and the impact of these strategies on the production economics. Though the oilfield literature contains discussions of the models and methods for estimating the expected number of ESP failures, little discussion has been presented on the confidence of such estimates. This study contains details of how the choice of model, parameter estimates and variation in a well's economic criteria affect the confidence limits. It shows that the uncertainties inherent in the continuous replacement of ESPs and the estimation of their run lives may make the estimates of the number of failures across an entire field to be numbers with considerable uncertainty. This effect is particularly pronounced during the first few years after field start-up. Under these circumstances the distribution of the number of failures is skewed and a 60% difference between the estimated and recorded number of failures is possible. Statistical models also enable differentiation in performance between manufacturers and technologies. It is

shown that even large differences in measured run life may not be conclusive evidence of technical or manufacturing superiority. Based on these results, actions are suggested to reduce the uncertainty and improve the management of a field.

For fields employing ESPs as the primary artificial lift method, the workover costs to replace failed ESPs are usually a significant proportion of the operating costs. Large differences between the failure rates predicted before sanction and those observed once operations have started can seriously affect a project's economics. Because of this, an accurate estimate of the expected number of failures at each stage of the development and the associated uncertainties is important. A number of factors affecting ESP run life have been identified and discussed in the literature. In some cases an attempt has been made to incorporate these factors in to statistical models of the failure data in order to predict the expected number of failures over some future time period. Both the exponential and Weibull distributions have been used in this way. Much attention has been paid to the development of the models, but little has been discussed regarding the confidence of the predictions resulting from their use and the circumstances under which the predictions are valid. To better define these, a review of the modeling and prediction processes has been conducted.

1. The uncertainties inherent in the continuous replacement of ESPs and the estimation of their run lives may make the estimates of the number of failures across an entire field to be numbers with considerable uncertainty.
2. Knowledge of the Homogeneous Poisson Process can be used to estimate ESP run life and predict future failures based on small data sets encountered during field start-up.
3. Parameter estimates of the adopted models need to be updated frequently during this time.
4. Meticulous record keeping of the reliability data is necessary. Field knowledge can be used to provide qualitative supplemental information.
5. Formal reliability analysis methods should be used to differentiate alternative technologies and manufacturers.
6. Statistically, there is less uncertainty in failure rate for dual ESPs compared to single systems. Dual systems should therefore be more manageable.

7. ESP failure data should be shared at an industry level to identify general sensitivities and reduce the uncertainty associated with small data sets.
8. Budgets should be constructed recognising the inherent uncertainty in the predicted number of failures. Ensure the sensitivities are understood.
9. The uncertainty in the parameter estimates should be incorporated in to the Monte-Carlo type simulators to improve their range of application and avoid serious misinterpretation.
10. The influence of wear and the application of the non homogeneous Poisson process models to ESPs should be investigated further. [21]

P.A. Kallas made a study on sizing an electical submersible pump in a solution-gas drive horizontal well, in 1992. A model has been developed to optimize sizing the staging and brake horsepower requirements for an electrical submersible pump (ESP) in a solution-gas-drive horizontal well. Three components are examined by the model, reservoir inflow performance, casing and tubing outflow performance and pump performance. Since severe gas slugging has been a characteristic of many horizontal wells, the gas slugging potential is monitored during the pressure traverse from where the fluid flows into the wellbore to the pump set depth. Flexibility for handling the gas at the pump intake has been included. The model can take into account the gas removed by a gas separator and the gas produced up the annulus. Actual data provided from horizontal wells producing with electrical submersible pumps has been used to verify the model's relative accuracy in sizing.

Old oil fields which still have enormous potential for production of hydrocarbon reserves are being given a second chance through horizontal drilling. The advent of new technology for horizontal wells and the subsequent increased drilling activity have brought new challenges to artificial lift methods also. The-expense of drilling and completing a horizontal well justifies a vast amount of planning before the well is spud. One contingency that should definitely be planned in a horizontal well is artificial lift. This work, although specific to sizing electrical submersible pump systems in solution-gas-drive horizontal wells has components which could be applied to other forms of artificial lift. The model is in the form of a computer program developed to run on a personal computer. The production system is divided into the inflow performance relationship (IPR), the casing and tubing, or outflow

performance, and the pump performance. The IPR equations used for horizontal wells by the model are relatively new, and this model has been a proving ground for their practical application.

Gas slugging is a familiar phenomenon in many horizontal wells. It can cause an electrical submersible pump to gas lock and to shut down. The model predicts two types of gas slugging while evaluating the pressure profile of the horizontal section of the dogleg. The casing size and the inclination angle of the horizontal section of the well can have a definite influence on this slugging potential. The model can be used on an existing well to optimize the flowrate, operating frequency, set depth, and well head pressure for production with the least amount of downtime from gas interference; or, it can be used to plan a well by optimizing the casing size and inclination angles to minimize the gas slugging potential.

The model will suggest a particular pump or set of pumps and the appropriate staging to produce a desired surface flow rate of fluid. It will also determine the required brake horsepower for the pump and gas separator to do the job. However, this information is useless if the equipment will not fit through the dogleg to the desired set depth. A number of petroleum companies before they drill the horizontal well are now sizing ESP equipment to go down into the horizontal section under the worst possible producing conditions. Computer analysis is available to determine the dogleg degree of severity limitations the drilling company will have to adhere to in order to get that equipment through the dogleg if it becomes necessary. This planning ahead eliminates a great deal of frustration. Planning a tangent in the dogleg and/or a flat segment at the beginning of the horizontal section where ESP equipment can be set without operating in a bind is also recommended. Case studies indicate that the model is a capable and effective tool for sizing an electrical submersible pump in a solution-gas-drive horizontal well.

1. A FORTRAN program for use on personal computers has been developed which will aid in the sizing of electrical submersible equipment in horizontal wells. This program is strictly a modeling tool and not to be perceived as a rigid answer or solution. It is the feeling of the author that it will take experience and intuition along with the prognosis the model gives to come to a working solution.

2. Because the model offers some flexibility to change flow rates, frequency, gas intake, set depth, and well head pressure, it can be used to optimize equipment and placement for the equipment in an existing well. But even more important in the authors estimation, is the potential to use this production model in the planning stages for a horizontal well by inputting various scenarios for casing sizes, could be used a planned well such as dogleg severity, and anticipated pressure and flow data, it to better plan for the event of artificial lift in a well yet to be drilled.

3. Since gas slugging is one of the biggest problems for artificial lift in horizontal wells, more analysis of the dogleg and inclination of the horizontal section and the casing sizes to be used by running this model before the well is drilled could minimize the gas slugging. The model has been used enough to indicate that the slugging most often seen in the horizontal well is terrain-dominated or severe slugging very much like that seen in riser-pipe systems, and it occurs more readily in long horizontal sections where the tail inclines back upward toward the surface. Pipeline type slugging can occur when there is an almost maximum drawdown on high volume wells. Or, in other words, when velocities are low, it is more likely severe slugging and when velocities are high, it will likely be pipeline type slugging. It will not be both as the first equation of Boe's criteria is the dividing line between them.

4. Although the model can propose a pump to go into a well, the reality may be that the pump will not go down through the dogleg. It can not be stressed enough that if a horizontal well is being planned, consultation should be made with artificial lift manufacturers before the well is drilled if there is the smallest possibility that the well will ever need artificial lift.

5. The gas separator's capability remains at this time an elusive entity, but with research occurring at Tulsa University on the subject and new advancements in equipment, eventually confidence will be gained in the figures entered for the percent of free gas by volume into the pump.

6. One of the newest pieces of technology to be utilized by the model is the IPR for horizontal wells. There has not been any opportunity to apply the parameters V and n beyond the 0% recovery factor for the Bendakhlia-Aziz[22] IPR. The Bendakhlia-Aziz IPR at 0% recovery factor is more optimistic for the horizontal well than the

Cheng IPR. Several times when trying to use the model to size equipment for wells, the author found that the operator of the well had flow expectations greater than the maximum flow capability of the Cheng IPR but within the maximum flow capability of the Bendakhlia-Aziz IPR. The author has a preference for using the Bendakhlia-Aziz IPR since most horizontal well ESP systems are installed with a variable speed motor controller which provides some flexibility in the production rate; and, the design is usually done on the high frequency end of the possible production range in order to assess the maximum brake horsepower required. As in all new evolving technologies these IPR equations may be refined or replaced as more horizontal wells are drilled, produced, and analyzed. [23]

R.E. Pankratz and B.L. Wilson made a study on predicting power cost and its role in esp economics. With the current pressure on profitability, the economics of oil production are being closely scrutinized by most producers. This study develops a method for estimating the power cost for electrical submersible pumping systems (ESP's) and views the role of power cost in the overall picture of economics for this types of artificial lift. To validate the procedure that is used, the calculations have been compared to actual data taken from field tests of operating ESP's.

The total economic picture of artificial lift would have to include many factors which are beyond the scope of the study. The study will limit itself to the factors that are involved in the choices an engineer has to make in the selection of ESP's.

There are two methods for establishing ESP operating costs. The simplest is to actually measure the power consumed. In situations where meters are installed on individual wells and monitored by the operator or the power company, this method is readily available and should be pursued. The major drawback to this approach is that it can only be applied to equipment that is already in operation or in locations that have metering available.

If the installation is new or individual well meters not available then power consumption must be projected from available data. A rigorous analyst must include every element in the system that will consume power. The method that follows develops power costs at the wellhead, including the requirements for the cable and the loaded motor based on the published manufacturers data and established

engineering principles. To adjust for total consumption, it uses a "rule of thumb" multiplier for switchboard and transformers efficiency losses.

Most ESP sizing procedures follow five basic steps;

1. Calculate the required total dynamic head (TDH) for the desired flow rate. This includes the lift for produced fluid relative to the inflow performance of the well, the losses in the tubing, and the required surface pressure.
2. Select the pump that will meet these conditions.
3. Size the motor to fit the pump.
4. Size the cable to meet the motor requirements.
5. Select the surface equipment for the cable and downhole equipment needs.

In general, the same steps are followed in calculating predicted power costs for an ESP system. The procedure starts after step 4, assuming that the downhole equipment and power cable have already been selected or are already in operation.

This study has presented a method for calculating power cost and overall economics for artificial lift with Electric Submersible Pumps. Since the method uses only published equipment performance data, established principles of Engineering and routinely available well parameters, it application to specific situations is straightforward. A field study over a wide variety of well and fluid conditions has indicated the method can be used with an average accuracy of 0.8%. The economic analysis has demonstrated that the power cost of an ESP installation can only he ignored if the expected life is exceedingly short or the cost incurred in replacement are extremely high. The economic analysis has also indicated that the run life of an over designed unit must be substantially longer than that of an optimized unit to justify the investment. It should be noted that for wells with high oil cuts, emulsion, viscosity, or gas problems, corrections for the performance of the pump and tubing. [24]

In M.L Powers' study on the depth constraint of electric submersible pumps the various factors that limit submersible pump operation at increasing depth are summarized. Explored in detail are two parametrically related constraints, pump-shaft horsepower capacity and thrust-bearing load capacity. The former limits the product of head and rate, and the latter limits head. Optimum shaft diameter for standard configuration pumps is shown to be a compromise between these two

factors. Head and rate limits resulting from these constraints are mathematically defined and graphically displayed, and means of expanding deep pumping capabilities are discussed. The effect of increased pumping depth on motor cooling is analyzed. It is shown that the temperature rise of fluid traversing the motor is proportional to head, independent of rate, and very sensitive to pump and motor efficiencies. The effect of elevated fluid temperatures associated with increasing depth on motor heat transfer coefficients is also demonstrated.

The purpose of this study is to help resolve a perceived dilemma; Pump manufacturers do not develop pumps of ultra-deep capability because there is no market for them. Similarly, oil producers might abandon ultra-deep discovery wells having low reservoir pressure because there is no means of pumping them. This study is intended to promote the interest of both groups in potential deep pumping capabilities.

Many obstacles to electric submersible pump operation arise as pumping depth increases. Constraining factors include pump housing burst pressure rating; the effect of lengthy power cables on motor starting, required surface voltage and power consumption; and the detrimental effects on motor and power cable life of higher ambient wellbore temperatures associated with increasing depth. Standard pump housing pressure ratings are approximately 5,000 psi for 4.00 OD and ±5.13 OD pumps. These limits can be increased slightly by special threading of housing ends, and somewhat more by various means of reinforcement of housing ends. However, thicker housings would be required for significant increases in pressure rating, which would increase the minimum casing ID required for installation. Thus, current pumps designed for 5.5 in. OD casing might require 6.625 in. OD casing. The undesirable effects of lengthy power cables can be reduced somewhat by use of cables having larger conductors than commonly used. This might also require larger casing. The temperature rise of produced fluid traversing the motor Is herein shown to be proportional to pump head, thus compounding the motor cooling problem of higher ambient temperatures. Conversely, convective heat transfer coefficients improve at higher fluid temperatures, thus aiding motor cooling. Discussed in the following topic are pump-shaft horsepower and pump-shaft thrust load, two

parametrically related factors that effect constraints on the product of head and rate (hq) and head (h), respectively.

1. As depth increases, optimum shaft diameter of standard configuration pumps becomes a compromise between horsepower capacity and thrust-bearing load.
2. Use of one or a combination of the means herein discussed for relieving the thrust-load constraint would significantly expand deep pumping capabilities.
3. In deep applications, the temperature rise of fluid traversing the motor could become important when the wellbore temperature is near motor operating limits, particularly at low pump and motor efficiencies.
4. Motor skin temperature rise (above contacting fluid temperature) is inversely proportional to $V^{0,8}$.
5. Motor skin temperature rise decreases as contacting fluid temperature increases, due primarily to viscosity reduction.
6. The variable speed drive should be of considerable utility in deep pumping applications. [30]

David L. Divine's study on variable speed submersible pumping systems gives a general idea on VSDs. A major new artificial lift system has been developed which will enhance the economics of many waterflood projects in West Texas and other recovery operations around the world. The new lift system consists of a standard oil well submersible pump and motor, a downhole pressure and temperature monitor and a static, variable frequency motor controller. The new system overcomes many of the problems associated with sizing larger lift equipment for secondary projects or any project in which an individual well's productivity may-be hard to predict and maintain. The new system has characteristics so different from a. standard or constant speed submersible pump installation that it truly should be considered a new pumping system and not just an enhanced submersible system. The ability to control lift and rate with speed changes has dramatic effects on the submersible pump and motor. Equipment life is extended, the pump's operation range is extended, energy requirements are reduced, and very often initial, artificial lift equipment investments are reduced.

This study covers the aspects and problems in sizing artificial lift equipment to point up the need for this producing system. The performance of the multistage deep well

submersible pump and motor when placed in a variable speed mode of operation will be addressed along with available 'test data which verifies that performance. Several implied system benefits such as extended cable and motor life and reduced impeller and bearing thrusts will be theorized and strengthened mathematically. The study will also cover the system's lift efficiency and economic benefits as compared to equivalent constant speed submersible pumps and sucker rod pumps. Also to be presented is the history of the first field trial, installed in August of 1977.

The downhole electrical submersible pumping system has been used in the oil field primarily in high volume lifting applications. The term "high volume" will have different meanings for different areas. If fluid is being lifted from formations at depths of 4500 feet or greater, then 600 to 700 BFPD may be high volume production. Generally speaking, an operator will look to the submersible pump in applications which extend beyond the range of a maximum size of conventional beam unit

High volume lift has been the principle use of the submersible even though submersible pumps are available to cover lift applications from 270 BFPD and up, at lifts up to 10,000 feet (total dynamic head). One of the reasons the submersible has not seen greater application is its lack of production flexibility once installed. Improperly sized equipment can lead to costly operations and early failures. It is the purpose of this study to discuss the problems in sizing submersible lift equipment and present an installed variable speed submersible pumping system which greatly extends the flexibility of the submersible pump. [31]

CHAPTER 3

INFLOW PERFORMANCE RELATIONSHIPS

The reservoir contribution to the wellbore is determined by the inflow performance relationship (IPR). This relationship is discussed in this section with the appropriate methods and equations.

3.1 RESERVOIR IPR

The relationship of the reservoir flowrate with respect to the flowing bottom hole pressure is the Inflow Performance Relationship or IPR of the reservoir. The IPR is a means used to measure the reservoir's producing capacity under a given set of conditions. The IPR is unique for a well at any given time in the well's producing life. As the well produces, the IPR will change, but this change is usually so gradual that it can be considered constant over relatively long periods of time. The key to optimizing a well's production is in maximizing the available energy of a well's IPR to yield the maximum potential for longer life at high flowrates. It is particularly important in the design of ESP systems to be able to adequately lift a determined volume of fluid as conditions of the well change.

The IPR is usually considered independent of any effects caused by the well completion such as perforations or gravel pack effects. Since the IPR is currently calculated from either a known productivity index or a test point flowrate and flowing bottom hole pressure, it will be assumed that these values are inclusive of any effects that might be considered completion influenced. Therefore, the IPR generated with SubPUMP will be considered a total IPR inclusive of any completion effects and no separate calculations for the completion is performed [5, 11].

3.2 IPR METHODS

The IPR can be expressed according to one of three methods. These are Productivity Index, Vogel, Vogel corrected for water cut (sometimes referred to as the composite method) [5].

3.2.1 Productivity Index Equation

Darcy's Law for the radial flow of single-phase fluid can be expressed as:

$$q = \frac{kA}{\mu}\frac{dp}{dr} \tag{3.1}$$

After doing some mathematical operations and changing these variables to reservoir variables, this equation can be re-expressed as:

$$P_e - P_{wf} = \frac{q\mu}{2\pi kh} S \tag{3.2}$$

Since production engineers frequently employ this equation, it is useful to express it in field units rather than the Darcy units in which it was derived:

$$P_e - P_{wf} = 141.2\frac{q\mu B_o}{kh}\left(\ln\frac{r_e}{r_w} + S\right) \tag{3.3}$$

This equation is frequently expressed as:

$$PI = \frac{q}{P_e - P_{wf}} \tag{3.4}$$

Where the PI or Productivity Index of a well, expressed in stb/d/psi is a direct measure of the well performance. It is much more practical to use PI relationship than Darcy's law because the PI can be obtained from tests on the well. On the other hand it may be difficult to find all the data required for Darcy's law.

The Productivity Index method is modeled by designation of the PI or Productivity Index of the well expressed in stock-tank-barrels per day per psi of drawdown. This relationship describes a straight line on a plot of flowing bottom pressure vs. flowrate starting at zero flowrate at the static reservoir pressure. The flowrate is related to the flowing bottom hole pressure (wellbore pressure) by the following relationship and the figure given in figure 3.1 [6].

$$Q = PI \times (P_r - P_{wf}) \tag{3.5}$$

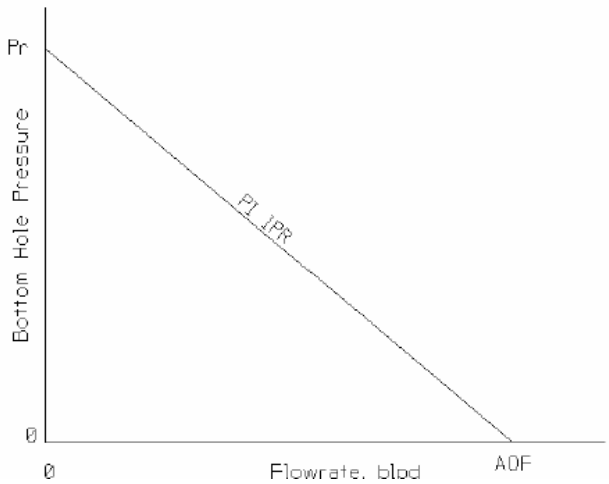


Figure 3.1 PI IPR [5]

3.2.2 Productivity index IPR

The Productivity Index IPR relies on the assumption that reservoir and fluid properties remain constant and are not a function of pressure. Although this holds true in some cases, especially in single-phase flow, wells that produce both oil and gas will be over-estimated using the PI relationship. The PI method will give the best results for a 100% water cut fluid. The oil phase of a water-oil fluid mixture contains dissolved gas, which will break out of solution when the fluid reaches its bubble point pressure. In this case, fluid properties change and will no longer be independent of pressure as assumed. As such, any oil and associated gas production will proportionally reduce overall inflow potential [5].

3.2.3 Vogel Method

The Vogel equation was developed empirically to describe the relationship of the wellbore pressure to the flowrate for solution-gas drive oil wells. When the pressure of the fluid is below the bubble point pressure, gas breaks out of solution into a gas phase. The PI relationship is used above the bubble point pressure. Vogel calculated dimensionless IPR curves using a computer for several fictitious solution-gas drive reservoirs that cover a wide range of oil PVT properties and reservoir permeability characteristics. These IPR curves were plotted with each pressure value divided by

the maximum shut-in pressure and each flowrate divided by the maximum rate Qmax at Pwf = 0. These dimensionless curves were combined into a general reference curve in the following form.

$$\frac{Q}{Q_{max}} = 1.0 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2 \tag{3.6}$$

IPR is used to present the well production rate as a function of the bottomhole pressure. Usually the bottomhole pressure is graphed on the ordinate and the production rate, q, is graphed on the abscissa. This relationship can be used for transient, steady-state, and pseudo steady state.

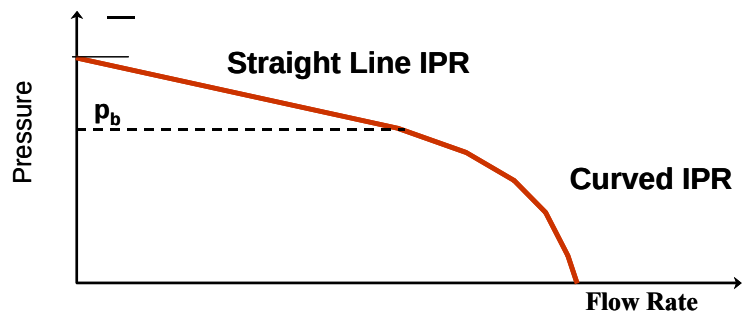


Figure 3.2 IPR Curve [3]

A non linear IPR has to be used instead of a PI when gas is present. Figure 3.2 shows the IPR curve. The equation can no longer be linear once the bottom flowing pressure (P_{wf}) is lower than the bubble point pressure (P_b) and free gas is present. Permeability, viscosity and formation volume factor are no longer constant. Darcy's law will give a higher flow rate than the real one because it doesn't consider the changes in permeability and viscosity caused by the appearance of free gas. The Vogel IPR curve considers all these changes.

The data required to generate the IPR curve is obtained by measuring the production rate under various drawdown pressures, this reflects the ability of the reservoir to deliver fluids to the wellbore. Combining this with a curve that represents the tubing performance identifies the operating point. Figure 3.3 gives the operating point.

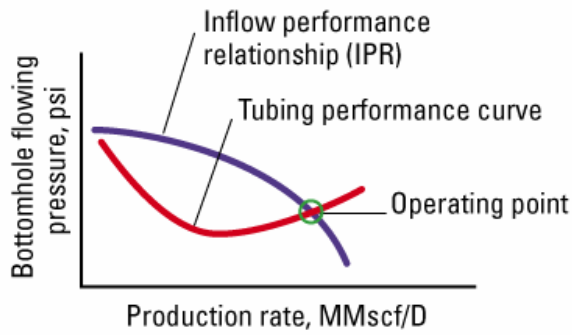


Figure 3.3 Operating Point [3]

The Vogel relationship can be regarded as a general equation for solution-gas drive reservoirs producing below the bubble point pressure. Above the bubble point pressure, the straight line PI is considered adequate [5]. The flowrate below the bubble point using the Vogel equation in the general form is:

$$Q` = Q_b + \left(Q_{omax} - Q_b\right)\left\{1.0 - 0.2\left(\frac{P_{wf}`}{P_b}\right) - 0.8\left(\frac{Pwf`}{Pb}\right)^2\right\} \tag{3.7}$$

3.2.4 Vogel IPR

The Vogel relationship was developed assuming a water cut of 0% (100% oil) and may give unacceptable or unreliable results when the water cut exceeds 60%. As the water cut in a well increases, the amount of free gas available to break out of the oil phase is less since there is less oil phase in the total fluid. If it is assumed that the PI method is adequate for the well with 100% water cut, then a well with a water cut between 0% and 100% will have an IPR somewhere between the Vogel (100% oil) and PI relationship (100% water). Figure 3.4 shows the Vogel IPR curve [5].

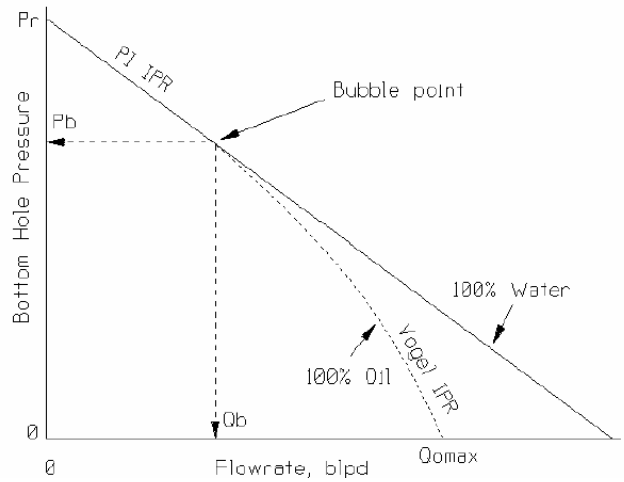


Figure 3.4 Vogel IPR [5]

3.2.5 Vogel Corrected for Water Cut

The Vogel corrected for water cut (composite) IPR method calculates an IPR for any water cut. If the water cut (fraction of water phase of the total oil plus water phase) is zero, the composite method matches exactly to the Vogel method. If the water cut is 100%, the composite method matches the PI method.

The Vogel methods require one known test point of flowing bottom hole pressure and flowrate. The equations and methodology in determining the IPR will be one of three scenarios.

1 Reservoir and test point pressures are above the bubble point pressure.

2 Reservoir pressure is above the bubble point pressure and the test point pressure is below the bubble point pressure.

3 Reservoir and test point pressure are below the bubble point pressure.

<u>IPR Equations—Reservoir and test point pressure above the BP pressure</u>

Figure 3.5 shows the case where IPR Reservoir and test point pressure are above the BP pressure.

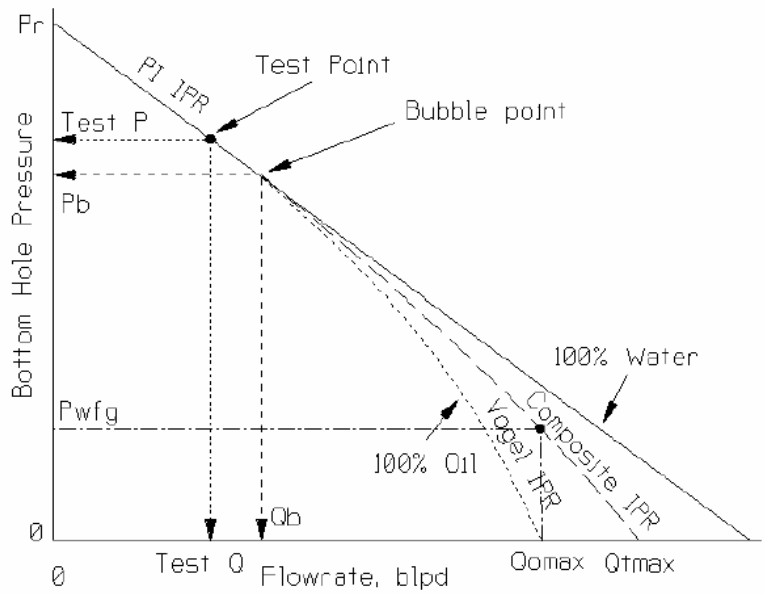


Figure 3.5 IPR Reservoir and test point pressure above the BP pressure [5]

The equations for the IPR are:

Productivity Index:

$$J = \frac{Q_{Test}}{(P_r - P_{Test})} \tag{3.8}$$

Oil Fraction:

$$F_o = 1.0 - F_w - \tag{3.9}$$

Bubble Point Flowrate:

$$Q_b = Jx(P_r - P_b) \tag{3.10}$$

Maximum rate at 100% oil:

$$Q_{o\max} = Q_b + \frac{JxP_b}{1.8} \tag{3.11}$$

Pressure on Composite IPR at Qomax flowrate:

$$P_{wfg} = F_w x\left(P_r - \frac{Q_{o\max}}{J}\right) \tag{3.12}$$

Geometric factors:

$$CG = 0.001xQ_{o\max} \tag{3.13}$$

$$CD = F_w x\left(\frac{CG}{j}\right) + F_o x0.125xP_b x\left(-1 + \sqrt{81.0 - \frac{80.0x\left(\left(0.999xQ_{o\max}\right) - Q_b\right)}{Q_{o\max} - Q_b}}\right) \quad (3.14)$$

Maximum flowrate of Composite IPR:

$$Q_{t\max} = Q_{o\max} + F_w x\left(P_r - \left(\frac{Q_{o\max}}{J}\right)\right)x\left(\frac{CG}{CD}\right) \quad (3.15)$$

The following equations calculate a flowing bottom hole pressure from a known flowrate using the results from the equations above:

If water cut is 100% and/or if Q is greater than Q_b then:

$$P_{wf} = P_r - \left(\frac{Q}{J}\right) \quad (3.16)$$

If water cut is less than 100% and Q is less than Q_{omax} then:

$$P_{wf} = F_w x\left(P_r - \left(\frac{Q}{J}\right)\right) + F_o x0.125xP_b x\left(-1 + \sqrt{81.0 - 80.0x\left(\frac{Q - Q_b}{Q_{o\max} - Q_b}\right)}\right) \quad (3.17)$$

If the water cut is less than 100% and Q is less than Q_{tmax} but not less than Q_{omax} then:

$$P_{wf} = F_w x\left(P_r - \left(\frac{Q_{o\max}}{J}\right)\right) - \left(Q - Q_{o\max}\right)x\left(\frac{CD}{CG}\right) \quad (3.18)$$

The following equations calculate a flowrate from a known flowing bottom hole pressure:

If water cut is 100% and/or P_{wf} is greater than P_b then:

$$Q = Jx\left(P_r - P_{wf}\right) \quad (3.19)$$

If water cut is not 100% and P_{wf} is greater than P_{wfg} then:

$$A = \frac{Pwf + \left(0.125xF_o xP_b\right) - \left(F_w xP_r\right)}{0.125xF_o xP_b} \quad (3.20)$$

$$B = \frac{F_w}{0.125xF_o xP_b xJ} \quad (3.21)$$

$$C = \left(2.0xAxB\right) + \left(\frac{80.0}{Q_{o\max} - Q_b}\right) \quad (3.22)$$

$$D = A^2 - \left(80.0x \frac{Q_b}{Q_{o\max} - Q_b} \right) - 81.0 \tag{3.23}$$

If B is zero then:

$$Q = \left| \frac{D}{C} \right| \tag{3.24}$$

If B is not zero then:

$$Q = \frac{-C + \sqrt{C^2 - \left(4.0xB^2xD\right)}}{2xB^2} \tag{3.25}$$

If P_{wf} is less than or equal to P_{wfg} and the water cut is not 100% then:

$$Q = \frac{\left(P_{wfg} + Q_{o\max} x \left(\frac{CD}{CG} \right) - P_{wf} \right)}{\left(\frac{CD}{CG} \right)} \tag{3.26}$$

<u>IPR Equations—Reservoir pressure above and test point pressure below BP pressure</u>

Figure 3.6 shows the case where reservoir pressure is above and test point pressure is below BP pressure.

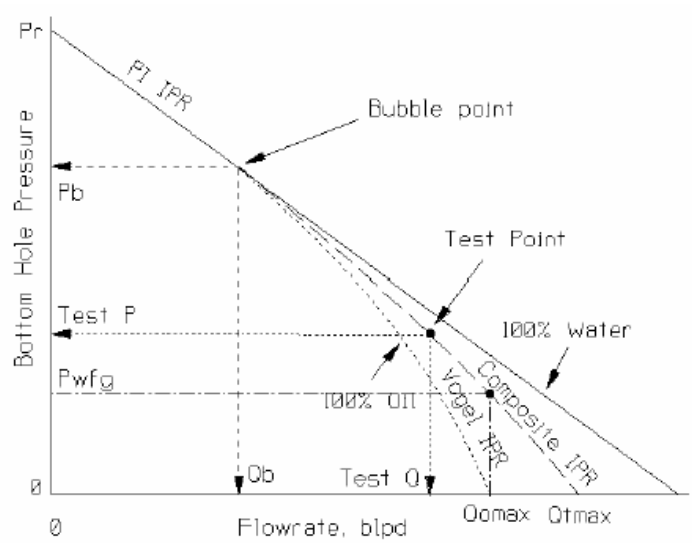


Figure 3.6 PI IPR Reservoir pressure above and test point pressure below BP pressure [5]

The previous equations all apply when the test point is below the bubble point pressure except that the Productivity Index (J) cannot be solved for directly since the test point is not in the straight line PI segment of the IPR curve. J is solved for, by iterating at the test pressure and test rate using the rate and flowing bottom hole pressure equations until a value of J causes the IPR curve to go through the test point.

An initial value of J is calculated as follows when the reservoir pressure is above and the test point pressure is below the bubble point pressure:

$$J_{init} = \frac{TestQ}{F_o\left(P_r - P_b + \frac{P_b\left(1 - 0.2\left(\frac{TestP}{P_b}\right) - 0.8\left(\frac{TestP}{P_b}\right)^2\right)}{1.8}\right) + F_w\left(P_r - TestP\right)} \tag{3.27}$$

<u>IPR Equations—Reservoir and test point pressure below BP pressure</u>

Figure 3.7 shows the case where reservoir and test point pressures are below BP pressure.

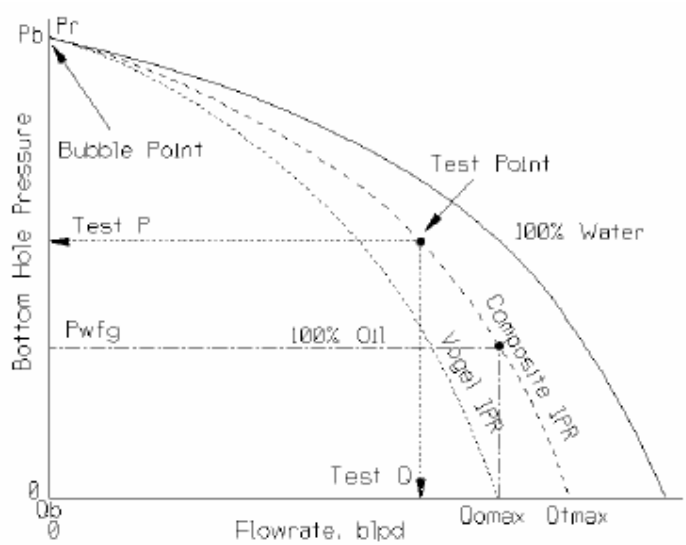


Figure 3.7 PI IPR Reservoir and test point pressure below BP pressure [5]

The previous equations all apply when the test point and reservoir pressure are both below the bubble point pressure except that the Productivity Index (J) cannot be solved for directly since the IPR does not have a straight line segment. J is solved for, by iterating at the test pressure and test rate using the rate and flowing bottom hole pressure equations until a value of J causes the IPR curve to go through the test point. The bubble point pressure P_b is set equal to the static reservoir pressure P_r since the reservoir fluid characteristics will change in the wellbore. This is because some of the solution-gas will be left behind in the reservoir as a gas phase and thus reduces the bubble point pressure of the fluid entering the wellbore [5].

An initial value of J is calculated as follows when both reservoir and test point are below the bubble point pressure:

$$J_{init} = \frac{Q_{Test}}{F_o\left(\frac{P_r\left(1-0.2\left(\frac{P_{Test}}{P_r}\right)-0.8\left(\frac{P_{Test}}{P_r}\right)^2\right)}{1.8}\right)+F_w\left(P_r-P_{Test}\right)} \tag{3.28}$$

The Skin factor can be added within the second set of braces in the denominator.

The various factors that influence the inflow performance relationship:

- Skin factor,
- Permeability,
- Viscosity,
- Oil Formation Volume Factor (Bo),
- Ratio re/rw,

CHAPTER 4

DESIGN CRITERIA AND METHODOLOGY

4.1 THE VARIABLE SPEED DRIVE

Until the appearance of the VSD, there were only two methods of changing the performance of an ESP from the surface. The unit could be choked or it could be cycled. Neither of these methods can increase the production from the unit and both had possible detrimental effects. The VSD offers the opportunity to increase or decrease the production rate from an ESP. To understand the limitations of units operated with VSD's, it is necessary to develop a general understanding of the design details of the VSD, the pump and the motor. The VSD belongs to a family of inverter drives. They are classified as non sinusoidal power sources. The voltage source type is the most commonly used with the ESP. The device operates by rectifying the incoming AC power. The DC is then used to construct a stepped pseudo sine wave whose frequency is adjustable. For efficient operation, the motor flux density must be kept at the designed saturation level. The VSD accomplishes this by holding the ratio of voltage to frequency constant. As the frequency increases, the voltage is increased accordingly. The VSD efficiency ranges from 85 to 96 percent depending on design and application [7].

4.2 THE PUMP

The pump is a multistage centrifugal device. The hydraulic performance of the pump is governed by four factors, the physical design of the stage, the properties of the fluid flowing through the pump, the number of stages and the RPM at which the pump operates. The performance of a particular stage is given in the form of a stage performance curve. Figure 4.1 shows a typical pump performance curve [7].

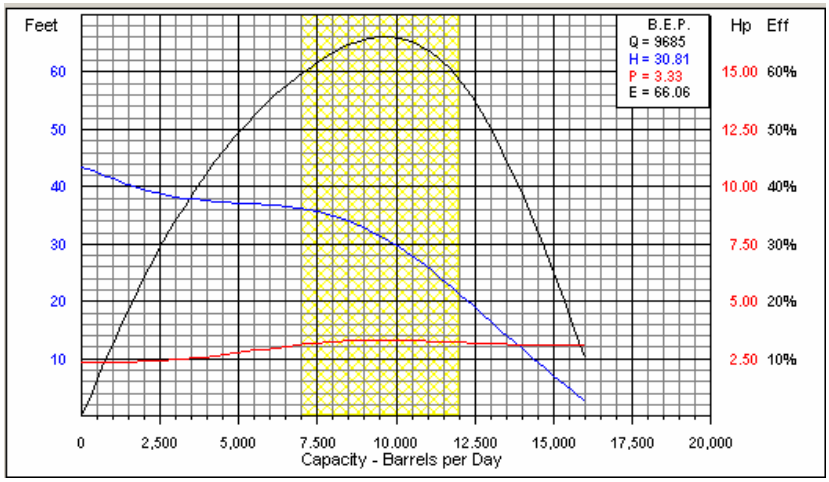


Figure 4.1 Pump Performance Curve [8]

The X axis represents the flow rate through the stage and the Y axis represents the differential head that the stage will produce. This curve represents the stage performance for water (sp.gr.-1) and a rotational speed of 3500 RPM. The efficiency and the required input horsepower are also represented. The pump performance is dependent on the specific fluid properties which are accounted for by using performance correction factors. The total pump performance is a multiple of the single stage performance for a specified flow rate. Except for cases involving high viscosity or gas cut fluid, all the stages can be considered to be operating at the same point on the stage performance curve.

$$\text{Total Differential Head} = \text{Head per Stage} \times \text{Number of Stages} \tag{4.1}$$

$$\text{Total Required HP} = \text{HP per Stage} \times \text{Number of Stages} \tag{4.2}$$

Three affinity laws give the relation between rotational speed and hydraulic performance:

- The flow through a pump is directly related to the speed.
- The head produced by a pump is directly related to the square of the speed.
- The power required by a pump is directly related to the cube of the speed.

Because the rotational speed of the ESP is related to the frequency of the power supplied, these laws may be expressed either in terms of RPM ratios or frequency ratios. Using a pump performance curve generated for 3500 RPM (60 Hz) , curves for any other frequency or speed can be constructed using the following relations:

$$Flow = Flow(3500) x\ (RPM/3500) \quad = Flow(3500) x\ (Hz/60) \tag{4.3}$$

$$Head = Head\ x\ (RPM/3500)2 \quad = Head(3500) x\ (Hz/60)2 \tag{4.4}$$

$$Hp = HP(3500) x\ (RPM/3500)3 \quad = HP(3500) x\ (Hz/60)3 \tag{4.5}$$

The first two relations have proven to be true over a wide range of speeds. The third is correct for hydraulic horsepower output by the pump, but because the internal losses do not exactly obey the cube law, careful testing may show a small increase in efficiency with increased speed. The third relation can be used for pump input power because these variations are slight. A family of variable speed performance curves is generated for a stage using these relations. Figure 4.2 shows the variable speed performance curve [7, 11].

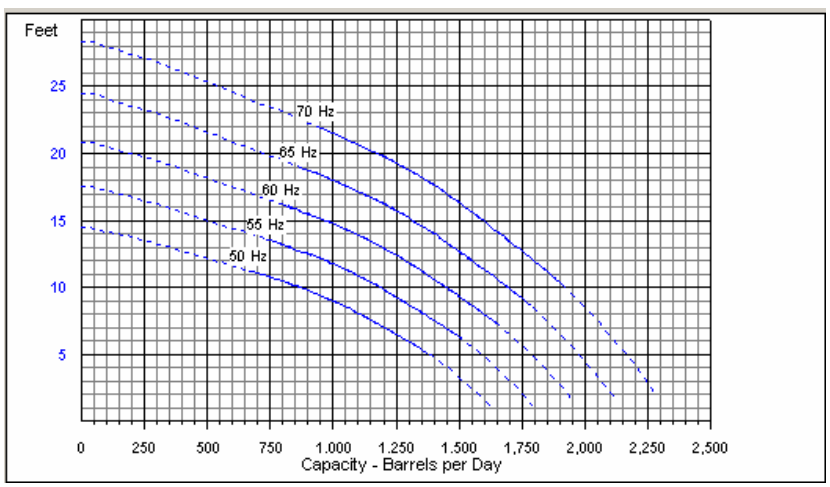


Figure 4.2 Variable Speed Performance Curves [8]

4.2.1 Pump Operating Ranges

There are points on the performance curve where the pump cannot be continually operated. It is common practice for the manufacturer to define one or two operating ranges. A "Best" operating range indicates that no other pump in that manufacturer's series has a higher efficiency for those flow rates. A "Useful" operating range is defined as the volume range over which a pump can be operated without detrimental effect, however, there are no industry-wide guidelines for determining this range. There are several factors considered in determining the limits of the useful range [7].

4.2.2 Pump Thrust

Without going into specific design, the total unbalanced thrust can be represented as the summation of two components, up thrust and down thrust. Simply stated, the upthrust is a function of the velocity of fluid flowing through a stage, and the downthrust is a function of the head produced by the stage. As flow is increased, the magnitude of the upthrust increases and the magnitude of the downthrust decreases, at some point the two thrusts will be equal. The total resulting thrust will be zero. This zero thrust point may or may not be in the operating range of the pump. For practical consideration, most stages are designed so that they always operate in downthrust [7, 9].

4.2.3 Pump Limitations

The minimum operating flow is generally set where either the magnitude of the downthrust exceeds the bearing capacity or where the performance curve is so flat that slight variation in intake pressure produces wild fluctuation in flow. The maximum operating flow is generally set either at the zero thrust point, or where the magnitude of the upthrust exceeds its bearing capacity. The design of some pumps is such that it either never reaches the zero thrust point, or reaches it very near its maximum flow. Operating close to maximum flow with nearly zero head is not truly useful. In these cases an arbitrary maximum flow is selected. Although it is possible to operate some pumps outside their given useful range, this should never be done without authorization from the manufacturer [7].

4.3 THE MOTOR

The motor is a three phases, two-pole squirrel cage, induction motor. It is designed to operate on a sinusoidal power source. The operating speed of these motors is governed by the physical design of the motor, the driving frequency and the slip. If the motor is operating at full load, the slip is constant. The speed is then a function of frequency only. The motors are designed to run fully loaded at 3500 RPM on a 60 Hz power source. The speed of any other frequency is found by the following relation:

$$\frac{\text{RPM}}{3500} = \frac{\text{Hz}}{60} \tag{4.6}$$

The flux density is held constant by keeping the voltage/frequency ratio constant. The available torque is proportional to the square of the voltage/frequency ratio and is therefore also constant. The output horsepower is directly related to the torque times the speed. The horsepower will increase directly with the speed. The horsepower at any frequency can be found by the following relation:

$$HP = HP(60Hz) x \left(\frac{Hz}{60}\right) \tag{4.7}$$

Motor Limitations

The motor has mechanical and thermal operating limits. The mechanical limitations are based on design and fatigue life of the materials. The thermal limits are determined by the temperature rating of the electrical insulation material. The internal motor temperature depends on the losses generated in the motor and the motor cooling rate. If the motor exceeds its internal temperature limits, the insulation will degrade and the motor will fail.

The motor is cooled by the well fluid flowing past it. The cooling rate is a function of the fluid velocity, the surface area and the well temperature. The manufacturers publish minimum fluid velocities for proper operation. Due to the physic of forced convection cooling, increasing the velocity above the recommended minimum value does not significantly increase the cooling. In designing motors, the diameter is limited by the casing size. Higher horsepowers are obtained by increasing the length. The surface area is increased proportionally and the cooling rate remains constant. The well temperature directly affects the internal temperature of- the motor. A motor that is designed for a maximum well temperature of 250° F will run safely in a 250° F well if it is not overloaded [7].

4.4 ESP OPERATION WITH VSD

The frequency of the VSD is easily adjusted. It is therefore easy to run the ESP beyond its rational limits. The horsepower required by the pump increases by the cube of the RPM, but the horsepower supplied by the motor functions directly with the RPM. Since the surface area for cooling the motor is constant, increasing the output horsepower increases the internal temperature. In addition the motor is designed to operate on a sinusoidal power source. The non sinusoidal power

supplied by the VSD places an additional thermal burden on the motor. Work is presently being done to define accurate guidelines to compensate for this additional burden. The VSD deration factors are presented as preliminary guidelines for motor sizing. The derated horsepower is found by dividing the calculated horsepower by the deration factor [7].

$$\text{Hp(derated)} = \frac{\text{HP (calculated)}}{\text{Deration Factor}} \tag{4.8}$$

4.5 PRESSURE VERSUS HEAD

Pressure exerted by a fluid on a surface is the force per unit area in pounds per square inch or PSI in Oilfield units. For a liquid at rest, the pressure at any point is equal to the pressure acting on the free surface plus the pressure from the weight of the fluid above the surface. This pressure relates to the column of fluid above a point on the surface by the relationship:

$$\textit{Pressure , psi} = \gamma \text{ x } H \tag{4.9}$$

The specific gravity of oil comes from the API gravity from the equation:

$$\textit{Sp.gr.} = 141.5/(131.5+\text{API}) \tag{4.10}$$

The height of the shut in fluid column is called the *static head* in oilfield units of length (feet). Pressure and head, therefore, relate to each other in oilfield units as:

$$\text{Head, ft.} = (2.31,\text{ft./psi x Pressure,psi}) / \text{Sp.gr.} \tag{4.11}$$

The gradient of the fluid column is calculated as:

$$\gamma, \text{ psi/ft} = \text{Sp.gr.} / 2.31,\text{ft/psi} \tag{4.12}$$

Centrifugal pumps convert rotational kinetic energy into head. They do not convert energy into pressure. The head output of a centrifugal pump is always a constant for any given flowrate. The flowrate through a centrifugal pump is calculated from the difference in the intake and discharge pressure and the head required to obtain that pressure difference.

It is therefore more convenient to discuss and analyze ESP systems in units of head rather than in the amount of pressure increase obtainable. If the flowrate can be determined, available pump intake pressure, and required pump discharge pressure, a pump capable of generating the required head to produce the well can be selected and designed under these conditions.

4.6 OUTFLOW CORRELATIONS

There are several tubing or outflow correlations to choose using the wellbore correlation list in the Wellbore dialog. Some of the correlations and suggested usage are:

MONA Modified (1986) [17], MONA (1986) [17], Mukherjee & Brill (1983) [27], Beggs and Brill (1973) [15], Ansari Mechanistic (1987) [28], Sylvester & Yao (1987) [29], Aziz et al. (1972) [16], Orkiszewski (1967) [14], Duns & Ros (1963) [13], Hagedorn & Brown (1965) [12], Fancher & Brown (1963) [25], Baxendall & Thomas (1961) [26], Poettmann & Carpenter (1952) [18].

4.7 DIRECTIONAL SURVEY CALCULATIONS

Directional data is entered as measured depth (MD) and true vertical depth (TVD) data pairs or measured depth to the point of deviation and the angle of deviation. The survey data is used to calculate the angle of the wellbore for specific sections of the tubing and casing to be used in the tubing correlations and for converting from TVD to MD and vice versa. The TVD values are considered in calculations using fluid gradients since gradients are always parallel to a vertical vector to the center of the earth. Friction calculations and equipment location, such as pump depth, use the MD values since these values use the length of pipe represented by the MD. Figure 4.3 shows the MD-TVD calculation.

A few rules are checked for consistency after the data is entered:

- The TVD can never be greater than the corresponding MD entered for any data point.
- The change in TVD can never be greater than the change in MD between any two consecutive data points.
- Any data pairs with zero for both MD and TVD are ignored. The wellhead is assumed to be at this location.
- No MD or TVD value can be less than or equal to zero.
- Any data pairs that cause the arc cosine function to give invalid results will flag an error message and require that the data point be corrected before calculations will proceed.

- A message is generated if the angle exceeds 70 degrees from vertical. This message flags that you may wish to install a bladder seal section.

Example:

MD (ft)	TVD (ft)
2000	2000
5000	4719
7000	6675

The first data pair included in the directional survey automatically (but not listed) is the surface location at point 1 in the diagram with a zero MD-TVD. If the data pair 0,0 is entered, it will be ignored since a well can have only one data pair at the origin. The first data pair entered should be the last location where the vertical section of the well is to be considered. The MD and TVD will be the same value as at point 2 in the diagram. This location is usually the kick-off point where deviation of the wellbore will begin.

The value entered for point 3 in the diagram will be the first location at a deviated position in the wellbore. This value will be used to calculate the angle of the wellbore between points 2 and 3. The inverse cosine function is used to calculate the angle of the well with the following equation [5].

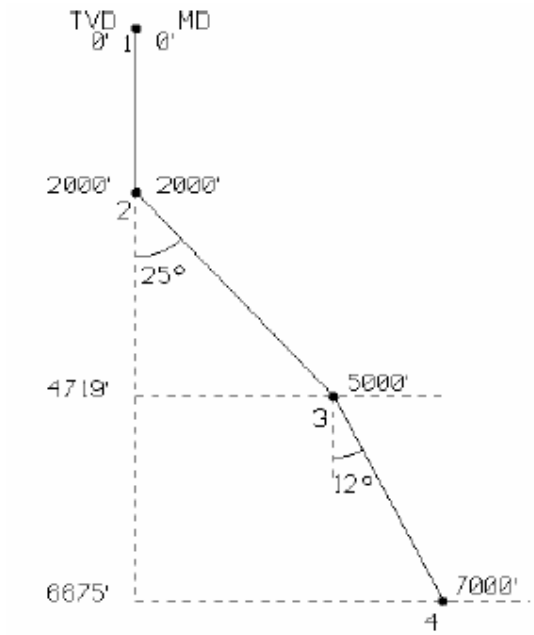


Figure 4.3 MD- TVD Calculation [5]

$$\text{Angle} = \text{acos}\left(\frac{\Delta\text{TVD}}{\Delta\text{MD}}\right) \tag{4.13}$$

The angle at point 2 is:

$$\text{acos}\left(\frac{4719 - 2000}{5000 - 2000}\right) = \text{acos}\left(\frac{2719}{3000}\right) = \text{acos}\left(0.9063\right) = 25^{\circ} \tag{4.14}$$

The angle at point 3 is:

$$\text{acos}\left(\frac{6675 - 4719}{7000 - 5000}\right) = \text{acos}\left(\frac{1956}{2000}\right) = \text{acos}\left(0.9780\right) = 12^{\circ} \tag{4.15}$$

Once the angles for all of the sections of the survey are calculated, the following formulas are used to convert between TVD and MD values in the wellbore depths.

4.7.1 Calculate a TVD from an MD

For example we will use the survey above to calculate the TVD at an MD of 5500 ft.

1 Determine the TVD, MD, and angle at the data point in the directional survey just above the desired MD. The previous depth would be at point 3 where the TVD is 4719 ft and the MD is 5000 ft with an angle of 12°.

2 Calculate the TVD.

$$\begin{aligned} \text{TVD} &= \cos\phi\left(MD - MD_{pt}\right) + TVD_{pt} = \\ &\cos\phi\left(12^{o}\right)\left(5500 - 5000\right) + 4719 = \\ &0.978x500 + 4719 = 5208\ ft \end{aligned} \tag{4.16}$$

4.7.2 Calculate an MD from a TVD

For example we will use the survey above to calculate the MD at a TVD of 2615 ft.

1 Determine the TVD and MD, and angle at the data point in the directional survey just above the desired TVD. The previous depth would be at point2 where the TVD is 2000 ft and the MD is 2000 ft and the angle is 25°.

2 Calculate the MD.

$$\begin{aligned} \text{MD} &= \frac{\text{TVD - TVD}_{\text{pt}}}{\cos \text{f}} + \text{MD}_{\text{pt}} = \\ &\frac{2615 - 2000}{\cos\left(25^{o}\right)} + 2000 = \\ &\frac{615}{0.906} + 2000 = 2679\ ft \end{aligned} \tag{4.17}$$

4.7.3 Undulating Well

The directional survey can be used to represent a well with a rising and falling profile, as shown in the Figure 4.4. In this case, the angle with the vertical can be greater than 90 degrees. The process to enter data in this situation is illustrated with the Table 4.1 [5]:

Table 4.1 MD-TVD data

MD m	**TVD m**	**Angle**
3000	3000	8.11
4000	3990	30.57
5000	4851	100.02
6000	4677	60.00
7000	5177	95.56
8000	5080	0.0

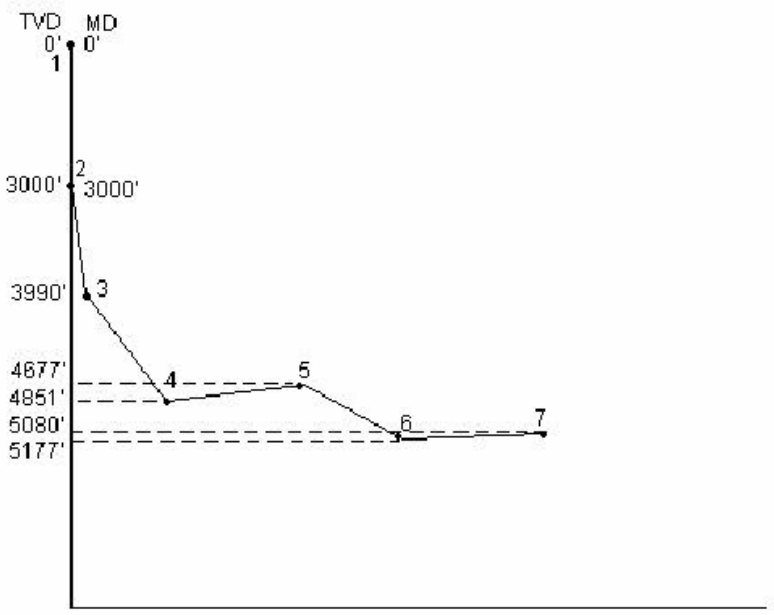


Figure 4.4 Undulating Profile [5]

4.8 FLOWLINE

This includes pipe, choke, elevation data and separator conditions at the end of the surface line. The correlations available for pressure drop calculations are : Xiao Mechanistic, Beggs Brill,& Minami, Dukler, MONA, MONA Modified, Mukherjee & Brill, Beggs & Brill [5].

4.9 PVT LAB DATA

SubPUMP calculates the required PVT data using any of the selected correlations in the PVT correlation dialog. In case some measured data is available, SubPUMP will use this PVT data to adjust or calibrate the calculated properties to match the values given. A calibration factor is calculated and applied to each property specified in the values given at any temperature and pressure to minimize the difference between calculated and measured values [5].

4.10 VISCOSITY CALIBRATION

Oil viscosity is calculated using the oil viscosity correlations designated in the PVT correlation dialog from the Fluid data dialog. The oil viscosity is calculated using the user selected correlation choices for dead oil, saturated, and undersaturated oil viscosity. The oil viscosity correlations can be calibrated to closely match actual laboratory viscosity values using the Viscosity Calibration dialog. The calibration process requires entry of one, two, or three known viscosity values at specified temperatures and pressures as either a dead oil or undersaturated oil viscosity value. Since oil viscosity is a crucial parameter in the overall well system calculations, having the oil viscosity calibrated to actual data can improve calculation accuracy.

The oil viscosity correlations were derived from general empirical data and will usually calculate an oil viscosity with a marginal discrepancy when compared to actual laboratory oil viscosity. With the correlations calibrated to actual data, this discrepancy can be minimized thus yielding a higher accuracy in predicting the oil viscosity values as the pressure and temperature change while the oil moves through the various components of the well system.

The viscosity data points must satisfy the conditions of at least one of the following three scenarios.

- Three-dimensional—requires three data points. Input any three known oil viscosities at two or three user-defined pressures and temperatures. SubPUMP will calculate oil viscosities for each of the three-pressure/temperature pairs. A three-dimensional correction array defined by a viscosity correction plane will be generated which defines the ratio of actual to calculated oil viscosity versus pressure and temperature. All remaining oil viscosity calculations will use SubPUMP's internal viscosity correlations, adjusted to actual conditions with the three-dimensional correction array. A warning occurs if the data points are co-linear (all lie on the same straight line) and cannot describe a plane and no viscosity calibration is done. The data points cannot all have the same pressure or same temperature. User can have two temperatures the same and two pressures the same as long as no two data points have exactly the same values.
- Two-dimensional—requires two data points. Input any two known oil viscosities with two user defined pressures and one temperature, or two user defined

temperatures with one pressure. The two data points must have either the same pressure or the same temperature. No calculation is done if either neither have the same pressure or temperature. SubPUMP will then calculate oil viscosity correction factors for each of the two-pressure/temperature pairs. The resulting correction plane is used as above to adjust the calculated oil viscosity calculations internally.

- One-dimensional—requires one data point. Input any single known oil viscosity at a user-defined pressure and temperature. SubPUMP will calculate an oil viscosity for the pressure/temperature pair, as well as the ratio of the actual to calculated viscosity. All remaining calculations of oil viscosity will use SubPUMP's internal viscosity correlations adjusted to actual conditions using the calculated ratio [5].

4.11 METHODOLOGY

The well system contains three pressures that remain constant during the design process. These are the flowing wellhead pressure, casing pressure, and the static bottom hole pressure. By entering other information important items can be determined for the design such as pump depth, fluid over the pump, total dynamic head, friction loss, and tubing head.

The goal is to select a pump and design it to generate the required head to produce the well. This is determined by solving for one of three variables based on the IPR or enter all of the variables and disregard the IPR. SubPUMP can solve for pump depth, total fluid rate, or pump intake pressure by designating the other two variables. SubPUMP will give a solution for the case depending on which variable is allowed to fluctuate and the IPR response. The generalized steps SubPUMP uses to calculate the case depends on which variable is being solved for and the other input variables.

The inflow calculations must also take into account whether the pump is positioned above or below the top perforation depth. If the pump is placed above the perforations, the fluid level in the casing will be allowed to fall to the limit of the pump depth. An absolute open flow point will be calculated with the fluid level at the top perforation depth.

If the pump is positioned below the top perforation depth, then under no circumstances will the fluid level in the casing be allowed to fall below the top perforation depth.

If there is gas injection, the gas will help to reduce the required discharge pressure, therefore the pump will have to generate less head and, consequently, will require less stages to produce the well. Even though the number of stages and horsepower is reduced, and smaller pump and motor are required to install, additional power will be required to operate the gas compressor [5].

4.11.1 Wellbore Parameters

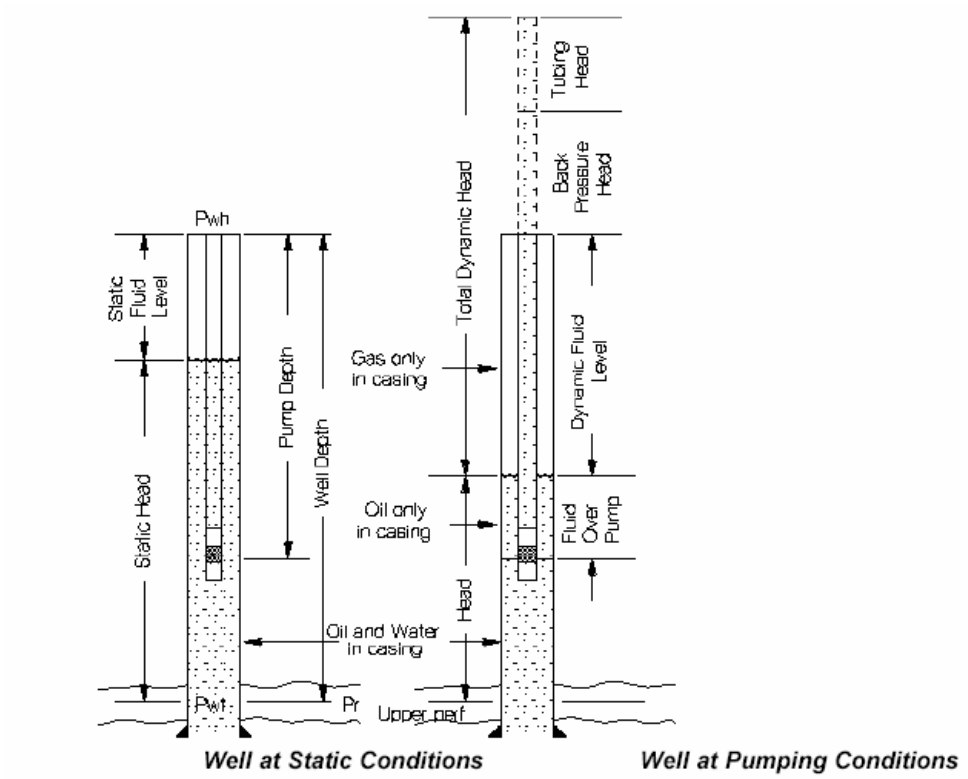


Figure 4.5 Wellbore Parameters [5]

4.11.2 Design with no motor slip

Calculations can include an adjustment for motor slip. Normal pump and motor calculations are based on the pump and motor rotating at 3500 RPM under loaded conditions. In actual practice, the motor load will cause the motor and pump to rotate

at some value less than 3500 RPM. This reduction in RPM is known as motor slip. With the reduced RPM, the pump will not be able to produce the required TDH needed to maintain the total fluid rate. Design calculations are used to generate an inflow and outflow response for the pump. The calculations are done according to which variable (Total Fluid Rate, Pump Intake Pressure, Pump Depth, or None) is being solved for and if the pump is above or below the upper perforation depth.

Calculations begin with the gas, oil, and liquid gradients being determined along with PVT data needed from the Fluid and Wellbore dialog information [5].

4.11.3 Solve for Total Fluid Rate

<u>Pump above the perforations</u>

Pump Intake Pressure (PIP) and Pump Depth are given.

The flowing bottom hole pressure at the upper perforation is calculated from the total liquid gradient, pump intake pressure, and depth of upper perforation and pump from the following equation.

$$P_{wf} = P_{ip} - (TVD_{pump} - TVD_{topperf})x\gamma l \tag{4.18}$$

The liquid gradient γl includes friction in the casing and gas effects and is calculated at an average pressure between the upper perforation P_{wf} and the pump intake P_{ip}. The Total Fluid Rate is subsequently calculated from the IPR equations discussed previously using the selected method either PI, Vogel, or Vogel corrected for water cut [5].

4.11.4 Solve for Pump Intake Pressure

<u>Pump above perforations</u>

You supply the Total Fluid Rate and Pump depth. The IPR equations are used with the TotalFluid Rate to calculate the flowing bottom hole pressure P_{wf} from the IPR at the upper perf. The Pump Intake pressure is calculated from the following equation.

$$P_{ip} = P_{wf} - (TVD_{upperperf} - TVD_{pump})x\gamma l \tag{4.19}$$

<u>Pump below perforations</u>

The Pump Intake pressure is calculated from the following equation.

$$P_{ip} = P_{wf} - (TVD_{pump} - TVD_{upperperf})x\gamma l \tag{4.20}$$

4.11.5 Solve for Pump Depth

Pump above the perforations

The flowing bottom hole pressure P_{wf} is calculated from the IPR at the upper perforation depth. The following equation calculates the Pump depth.

$$TVD_{pump} = TVD_{upperperf} - \frac{(P_{wf} - P_{ip})}{\gamma l} \tag{4.21}$$

Pump below the perforations

The Pump depth is calculated from the following equation [5].

$$TVD_{pump} = TVD_{upperperf} + \frac{(P_{wf} - P_{ip})}{\gamma l} \tag{4.22}$$

4.11.6 Calculate Pump Intake Pressure from Fluid Over Pump

Pump above the perforations

$$P_{ip} = (TVD_{pump} - FOP)x(\gamma_g - \gamma_o) + P_{csg} + (TVD_{pump} x\gamma_o) \tag{4.23}$$

Pump below the perforations

$$P_{ip} = P_{csg} + (TVD_{pump} - TVD_{upperperf})x\gamma l + (TVD_{upperperf} x\gamma_o) + (TVD_{pump} - FOP)x(\gamma_g - \gamma_l) \tag{4.24}$$

4.11.7 Calculate Fluid Over Pump

$$FOP = TVD_{pump} - TVD_{fluid} \tag{4.24}$$

4.11.8 Calculate Dynamic Fluid Level

Pump above perforations

$$TVD_{fluid} = \frac{P_{ip} - P_{csg} - (\gamma_o xTVD_{pump})}{\gamma_g - \gamma_o} \tag{4.25}$$

Pump below perforations

$$TVD_{fluid} = \frac{P_{wf} - P_{csg} - (\gamma_o xTVD_{topperf})}{\gamma_g - \gamma_o} \tag{4.26}$$

4.12 DESIGN CALCULATIONS

Once the pump depth, pump intake conditions, and total fluid rate are in equilibrium and all of the ranges and errors have been resolved, the well system curve is generated at various flowrates. The well system curve is built in STB (Oil + Water) units by calculating the total dynamic head (TDH) at various flowrates of the system through total fluid pump-off (dynamic fluid level is at the pump intake) and to absolute open flow (dynamic fluid level is at the top perforation depth).

The TDH curve is constructed by taking the difference in the discharge and intake curves and dividing it by the liquid gradient to calculate a TDH curve for this well. The intersection of the TDH curve with the total fluid rate is the design TDH as shown in Figure 4.6 [5].

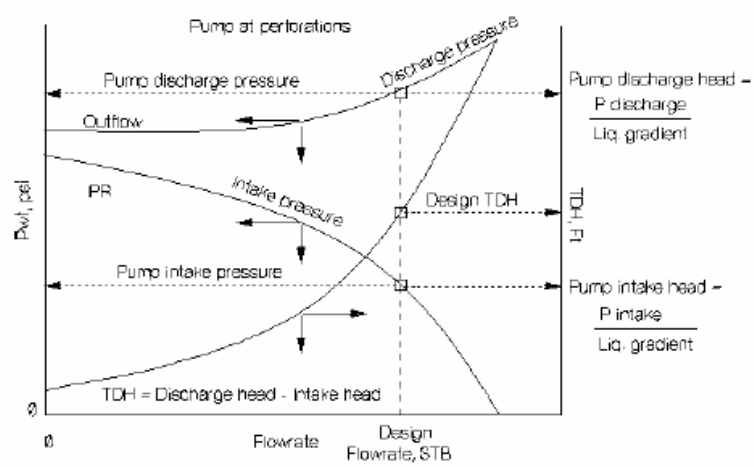


Figure 4.6 TDH [5]

The back pressure or wellhead pressure is considered as part of the tubing head in the calculations.

$$TDH = PDP_{head} - PIP_{head} \tag{4.27}$$

$$PIP_{head} = \frac{P_{ip}}{Liquid\ gradient} \tag{4.28}$$

$$PDP_{head} = BP_{head} + Tubing_{head} \tag{4.29}$$

$$BP_{head} = \frac{P_{wh}}{Liquid\ gradient} \tag{4.30}$$

$$Tubing_{head} = \frac{P_{dp}}{Liquid\ gradient} \tag{4.31}$$

4.12.1 Pump stage calculations

SubPUMP calculates the number of stages required to obtain the design TDH at the design frequency. Stages will be added to the pump until the total pump TDH is higher than the design TDH to ensure that the pump can maintain the desired flowrate. The pump curve is generated once the number of stages is determined to meet the design TDH. A warning message will appear if the fluid velocity around the pump housing is less than 1 ft/sec. A warning message will appear if the pump clearance is less than the default casing clearance. A warning message is displayed if the number of stages exceeds the maximum number of stages for a single pump housing.

The following list of parameters and functions are used in stage calculations. All are a function of the bubble point pressure [5].

1. Pressure In = Pressure out from previous stage.
2. FVF = f(Pressure In, Temperature, API, etc.)
3. Rs = f(Pressure In, Temperature, API, etc.). Note constant for gas compression.
4. Fluid Density = f(Pressure In, Temperature, API, etc.)
5. Viscosity = f(Pressure In, Temperature, API, correlation, etc.)
6. Fluid Density = f(Pressure In, Temperature, API, etc.)
7. Liquid Flowrate = f(STB rates, FVF, Rs, etc.)
8. Head = f(Liquid Flowrate, Frequency, Pump selected)
9. HP = F(Liquid Flowrate, Frequency, Pump selected)
10. Pressure Increase = f(Head, Liquid gradient)
11. Pressure Out = f(Pressure In, Pressure Increase)

4.12.2 Gas separator with free gas calculations

It is important in the calculation of the stages to determine the amount of free gas that is entering the pump intake.

The amount of free gas in the wellbore is dependent on the bubble point pressure and the pump intake pressure. As the fluid pressure drops below the bubble point, gas will break out into the gas phase. The total free gas is calculated as barrels:

$$\text{Total Free Gas} = \text{Gas in tubing} + \text{Gas in casing} \tag{4.32}$$

$$\%\ \text{Free gas available} = \frac{\text{Total free gas}}{\text{Total oil} + \text{Total water} + \text{Total free gas}} x100\ bbl/bbl \tag{4.33}$$

$$\text{Gas into pump} = \text{Gas in tubing} = (1 - \text{Nat. Sep.})\ \text{x}\ (1 - \text{Sep. Eff.})\ \text{x Total free gas} \tag{4.34}$$

$$\%\ \text{Free gas into pump} = \frac{\text{Gas into pump}}{\text{Total oil} + \text{Total water} + \text{Gas into pump}} x100\ bbl/bbl \tag{4.35}$$

Natural gas separation

Natural gas separation in tubing-casing annulus is an integral part of the overall bottomhole gas separation process. It could be affected by many factors, such as annulus area, flow rate and fluid properties.

In SubPUMP, the Simplified Alhanati's model is included as an option to provide an approximate estimate of the efficiency of natural gas separation.

There are two assumptions for the Simplified Alhanati's model. First, it is assumed that a uniform void fraction exists within the region surrounding the motor section up to the gas outlet ports. Second, no-slip condition exists between the gas and liquid phases for the region in front of the gas separator's intake port.

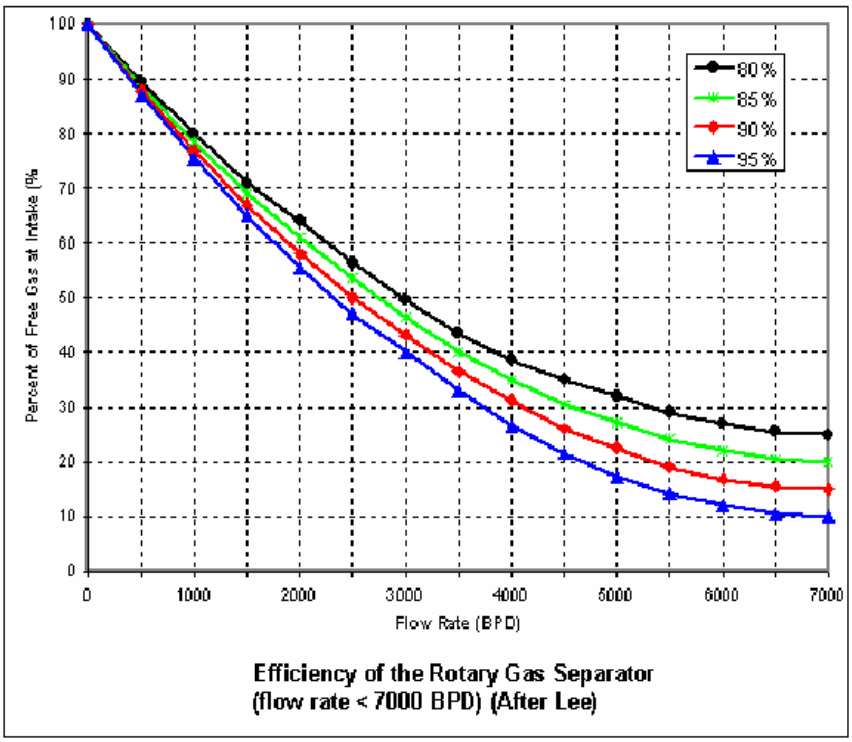
$$E = \frac{V_\infty}{V_\infty + V_{sl}} \tag{4.36}$$

$$V_\infty = \sqrt{2\left[\frac{\sigma(\rho_1 - \rho_2)g}{\rho_1^2}\right]}^{0.25} \tag{4.37}$$

Gas Separator

There are a few guidelines for gas separator applications, but all of them have some limitations. Moreover, different gas separators have different gas separation performance. Therefore, it is strongly suggested to obtain the efficiency information of specific separator from the manufacturer.

Two performance figures for rotary gas separator are shown here. These performance curves allow estimation of the Total Separation Efficiency, both natural and from separator, as a function of the Liquid Flow rate at intake. Figure 28 shows the efficiencies of the rotary gas separator [5].



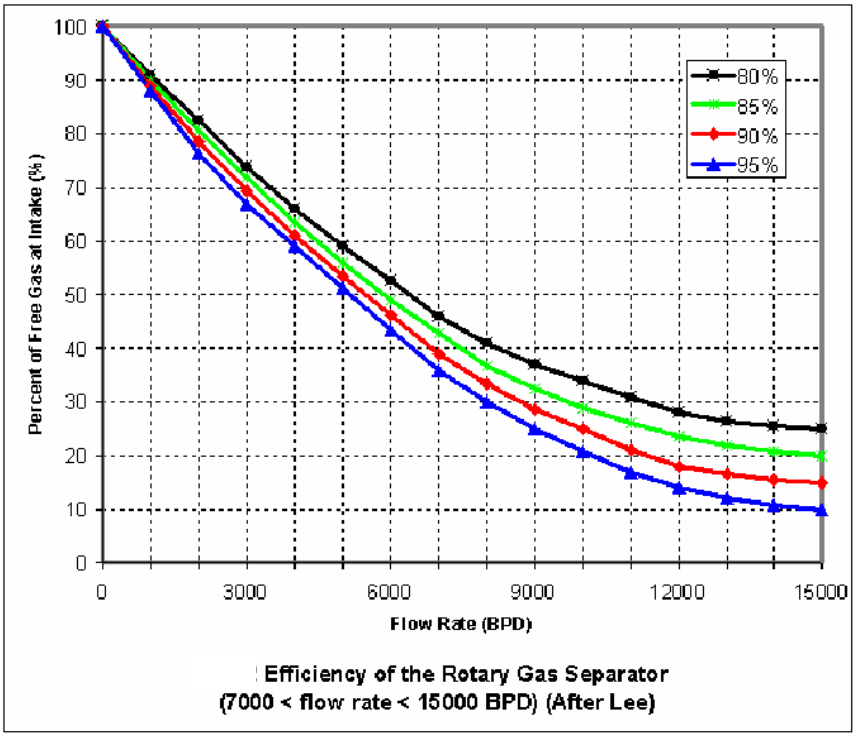


Figure 4.7 Rotary Gas Seperator Efficiency [5]

4.12.3 Required Pump horsepower

$$HP_{pump\,Hz} = \left[\left(\frac{\text{Design Hz}}{60}\right)^3 \text{x } HP_{pump\,60}\right] + HP_{GasSep\,Hz} + HP_{seal\,60} \tag{4.38}$$

4.12.4 Motor

The motor horsepower at 60 Hz and motor load factor at 60 Hz are calculated from these equations:

$$HP_{motor\,60\,Hz} = \text{HPmotor Hz x}\left(\frac{60}{\text{Design Hz}}\right) \tag{4.39}$$

$$MLF_{\,60\,Hz} = \frac{HP_{motor60\,Hz}}{NPHP_{motor}} \tag{4.40}$$

$$OMLF_{\,DesignHz} = MLF_{60Hz} \text{ x } \frac{\text{Design Hz}}{60} \tag{4.41}$$

<u>Motor slip</u>

The previous pump calculations were used to calculate the required horsepower of the selected pump at the design frequency. In selecting a motor, the required pump horsepower is converted to 60 Hz so that it can be used in culling the motor list and give a criteria for choosing a motor. In actual practice, the pump load on the motor will cause the motor to rotate at a lower RPM than required to drive the pump at the desired frequency. This lower RPM is referred to as motor slip.The RPM should be within 5% of the design frequency.

$$\left(1.0 - \left(\frac{RPM_{motor60Hz}}{\left(\frac{3500 \text{ x Design Hz}}{60}\right)}\right)^3\right) < 0.05 \tag{4.42}$$

where:

$RPM_{\,motor\,60Hz}$ = RPM of motor calculated from motor coefficients at 60 Hz, RPM

If stages are added to the pump to account for motor slip, then the RPM of the motor will be reduced, thus affecting the actual motor horsepower. The following equation is used to calculate the pump operating horsepower when the RPM is different than the standard of 3500 RPM.

$$HP_{pump\ actual} = \left(\frac{RPM_{pump\ w/slip}}{3500} \right)^3 \text{ x } HP_{pump60} \tag{4.43}$$

<u>Motor calculations</u>

Once the pump parameters are determined, the TDH, total required horsepower, amps, RPM, pump efficiency, motor efficiency, and power factor are calculated from the motor database coefficients.

$$RPM_{w/slip} = 3600 - RPM_{motor\,60hz} \tag{4.44}$$

A new RPM at the design Hz minus the RPM lost due to slip is calculated.

$$RPM_{DesignHz} = \left[\left(\frac{DesignHz}{60} \right) x3600 \right] - RPM_{w/slip} \tag{4.45}$$

A motor service factor to account for the effects of the wellbore temperature is calculated [5].

$$MSF = 1.0 - \left[0.002x\left(BHT - 190 \right) \right] \tag{4.46}$$

$$HP_{motor\ derated} = NPHP \text{ x } MSF \tag{4.47}$$

$$HP_{Motor\ inflated} = \frac{HP_{motor60Hz}}{MSF} \tag{4.48}$$

$$HP_{req\ at\ design\ Hz} = \frac{HP_{desgin\ Hz}}{MSF} \tag{4.49}$$

$$Amps_{motor} = NP\ Amps \text{ x } MAF_{coeff.} \tag{4.50}$$

$$V_{motor\ at\ design\ Hz} = V_{motor\ 60\ Hz} \text{ x } \frac{Design\ Hz}{60\ Hz} \tag{4.51}$$

CHAPTER 5

STATEMENT OF THE PROBLEM

The objective of this study is to perform a production engineering study at Y oilfield in Western Siberia Russia. Although there are many different artificial lift methods available, in this study only electrical submersible pumps will be used. The main goal of this study is to achieve production optimization and analysis of 10 electrical submersible pump systems for this field. All of the wells used in this study are deviated or horizontal wells.

The data that will be used in this case study is taken from SIBNEFT Company. The pumps will be selected from a given inventory from Reda Production systems' equipments. All the pumps will be operated with variable speed drives.

Design of the wells will be performed by using IHS Energy's SubPUMP 7.50 Software. After the design, optimization analysis for the wells will be done using the IPR curves and the pump performance curves for each well. The well curves will be tried to keep between the optimum operating ranges of the pumps. If this is not possible new sets will be selected for these wells.

CHAPTER 6

SUBPUMP OVERVIEW

SubPUMP is an advanced Windows™ software package for designing an efficient Electric Submersible Pumping (ESP) system and/or analyzing an existing ESP system. The program provides the user with pump, motor and other component information for the system from leading industry suppliers. SubPUMP's robust interface makes the process of entering data simple and fluent. It is designed to take the user step-by-step through all the input dialog boxes. SubPUMP's enhanced calculation engine enables the user to evaluate and/or optimize the ESP system.

Many input items have a custom units option available, which allows the user to enter the information in units with which is desired.

In Design mode, SubPUMP helps the user size, select, and design electric submersible pump systems. SubPUMP allows quick evaluation of many different equipment configurations to obtain an efficient and economical installation. A set of input data can be saved as a unique case for future use or comparison with other cases. The Pump database contains catalog specifications from various pump manufacturers and housing data for selected pumps. The Motor database contains catalog specifications for the corresponding manufacturers' electric motors. In addition, there is a protector database and cable database to complete the component selection of the system.

In Analysis mode, the components of the system are selected. SubPUMP calculates the input data and presents the results on several graphs and reports that can be viewed on screen or printed for analysis By using Mode Selection the user can choose to enter all required information for a Rigorous design, enter a reduced set of information in a Quick design, or enter the information for an existing system in Analysis. The SubPUMP screen is shown in the Figure 6.1 [2].

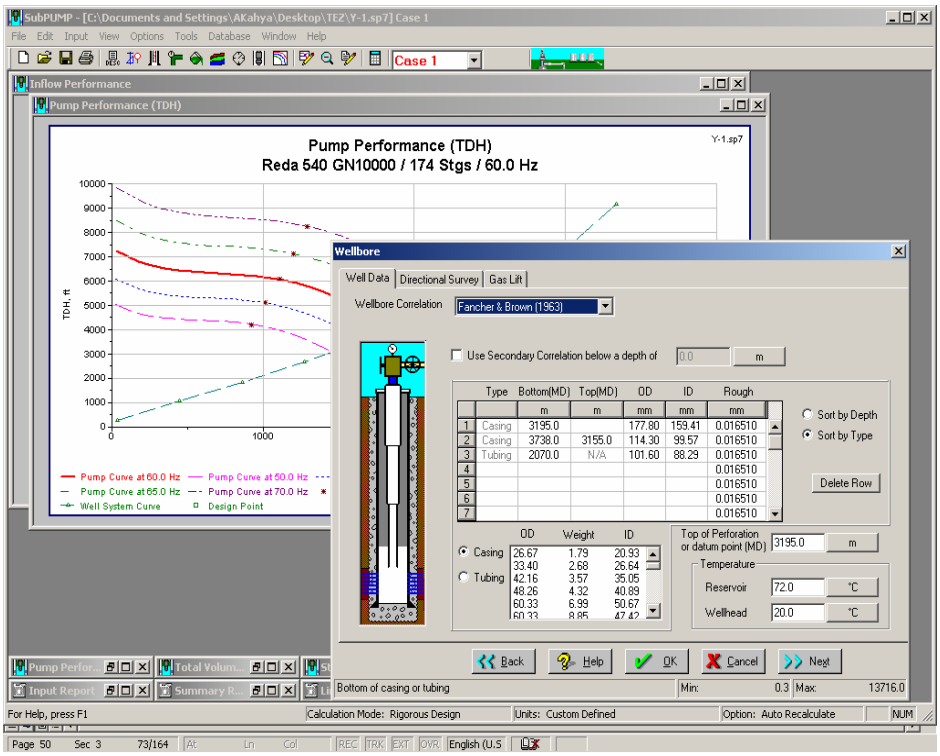


Figure 6.1 SubPUMP Screen [2]

6.1 WELLBORE

This dialog box is used to enter or alter Wellbore information including the Wellbore correlation, tubing and casing dimensions, pump depth (stated as total tubing depth), perforation depth, static bottom hole temperature at top of perforation, pumping wellhead temperature at surface, directional information for deviated wells, and gas lift parameters for combined ESP-gas lift installations.

The Wellbore dialog box includes the following three tabs, each of which contains its own set of data. Each tab is described in the following sections [2].

6.1.1 Well Data

Generally speaking, the Well Data dialog box allows to select a wellbore correlation for multiphase flow, specify the tubing and casing size, enter the reservoir and wellhead temperatures, and enter the top of perforation or datum point from which point the calculations start. Figure 6.2 shows the well data dialog box [2].

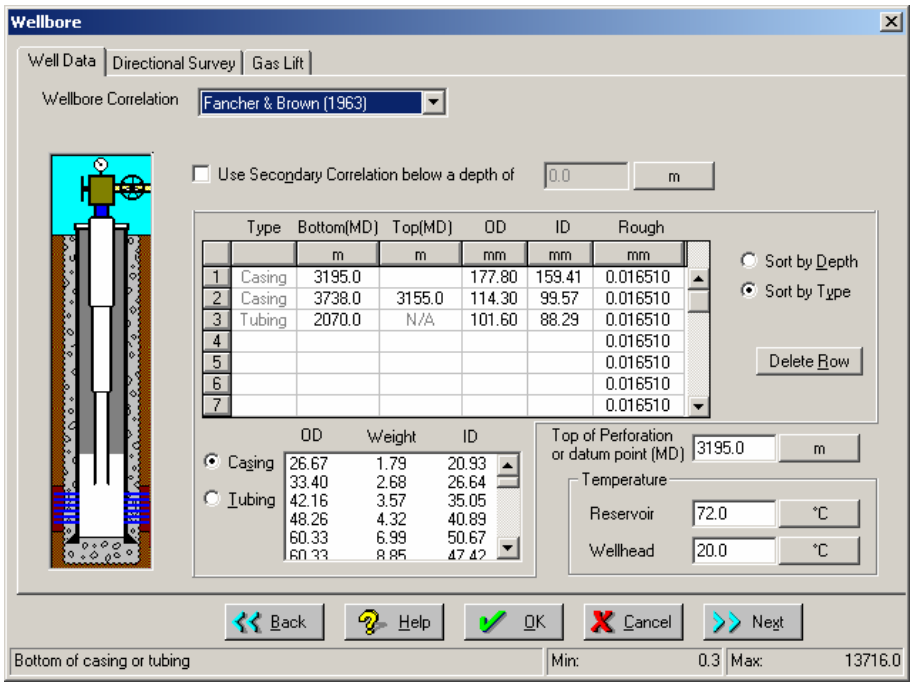


Figure 6.2 Well Data [10]

6.1.2 Directional Data

Directional Survey dialog box is used to enter data for deviated wells, calculate angle values by entering measured depth and true vertical depth, and calculate true vertical depth by entering measured depth and angle. After the directional information is entered, the survey data is plotted on the Directional Survey Graph. Figure 6.3 shows the directional survey dialog box [2].

6.1.3 Gas lift

This tab is used to enter gas injection information for dual ESP-gas lift installations. The injected gas will affect the fluid properties and thus a pressure drop in the wellbore, TDH, number of stages, and required HP at the pump. Figure 6.4 shows the gas lift dialog box [2].

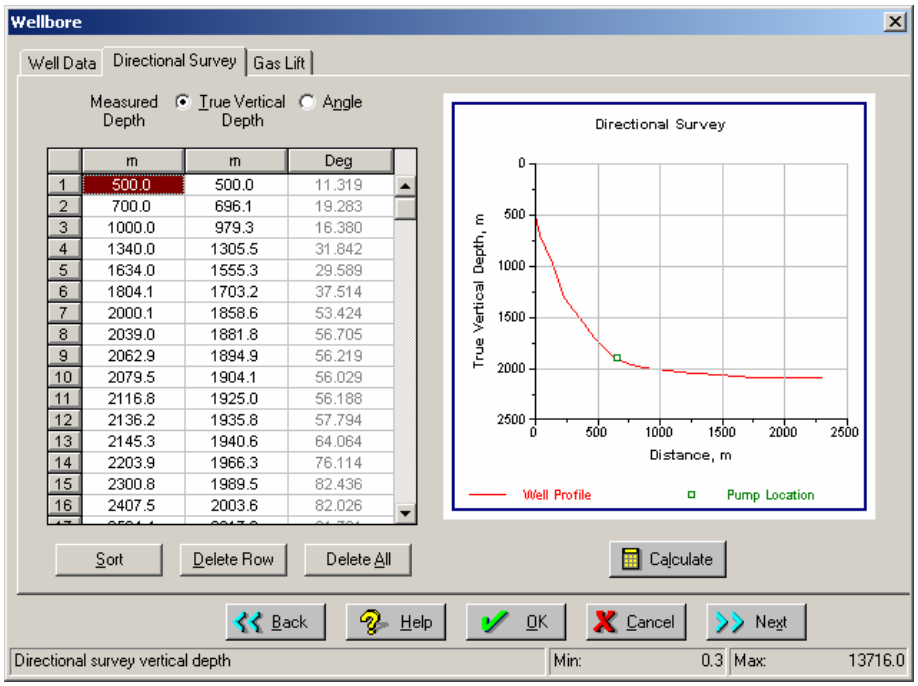


Figure 6.3 Directional Survey Dialog Box [10]

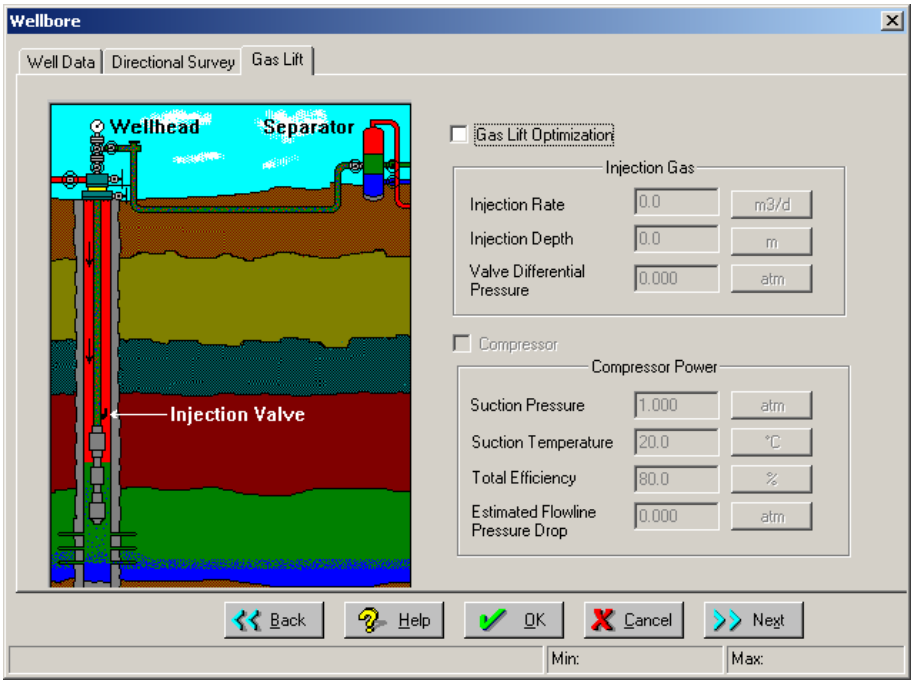


Figure 6.4 Gas Lift Dialog Box [10]

6.2 FLOWLINE

This dialog box is used to enter and change flowline information including the pipe and choke correlations, pipe distance to wellhead, restriction size, separator conditions and elevation information. Figure 6.5 shows the Flowline data dialog box [2].

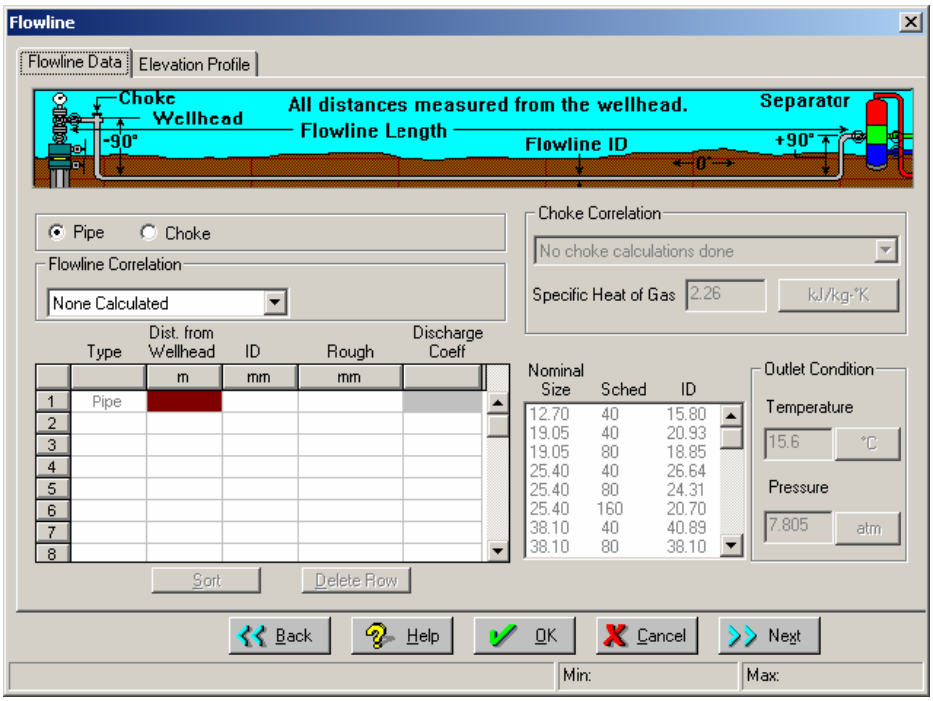


Figure 6.5 Flowline Data Dialog Box [10]

6.3 FLUID

The Fluid command is used from the Input menu or the toolbar to reach the Fluids dialog box. This dialog box is used to enter or alter fluid properties of the well.

The Fluids dialog box includes four tabs, each one containing its own set of data [2].

6.3.1 Fluid Data

The Fluid Data dialog box is used to input fluid specifications and properties, change the correlation method for fluid properties, enter measured PVT data to adjust the corresponding calculated value, and enter the measured viscosity data to calibrate the calculated viscosity. Figure 6.6 shows the Fluid data dialog box [2].

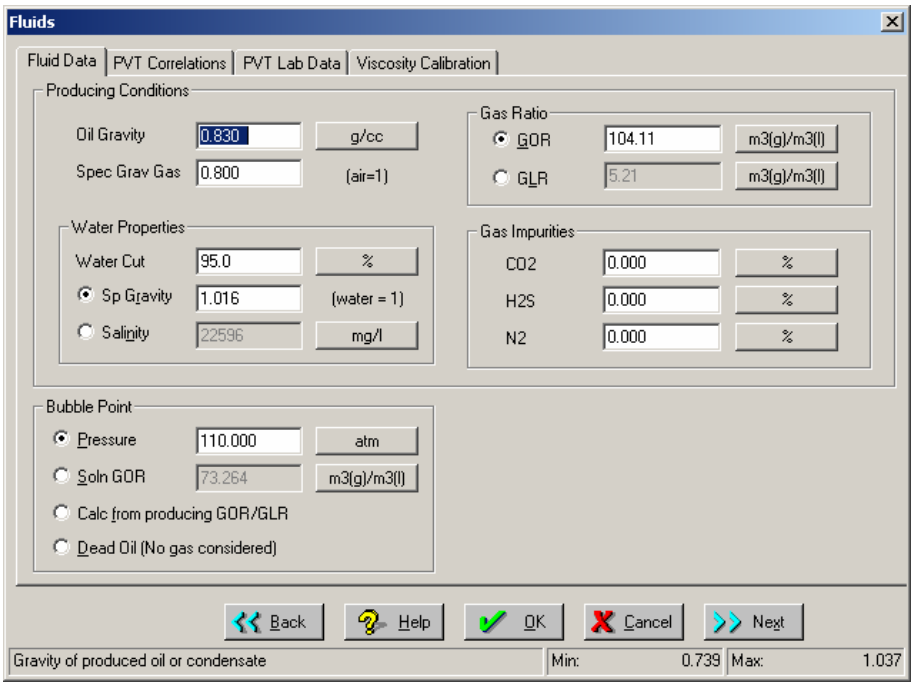


Figure 6.6 Fluid Data Dialog Box [10]

6.3.2 PVT Correlations

The PVT Correlations dialog box allows to select or change the fluid property correlations, set Separator Conditions (default values are 60° F and 14.7 psi), and save correlation settings as new default if desired for later recall. Figure 6.7 shows the PVT Correlations Dialog Box [2].

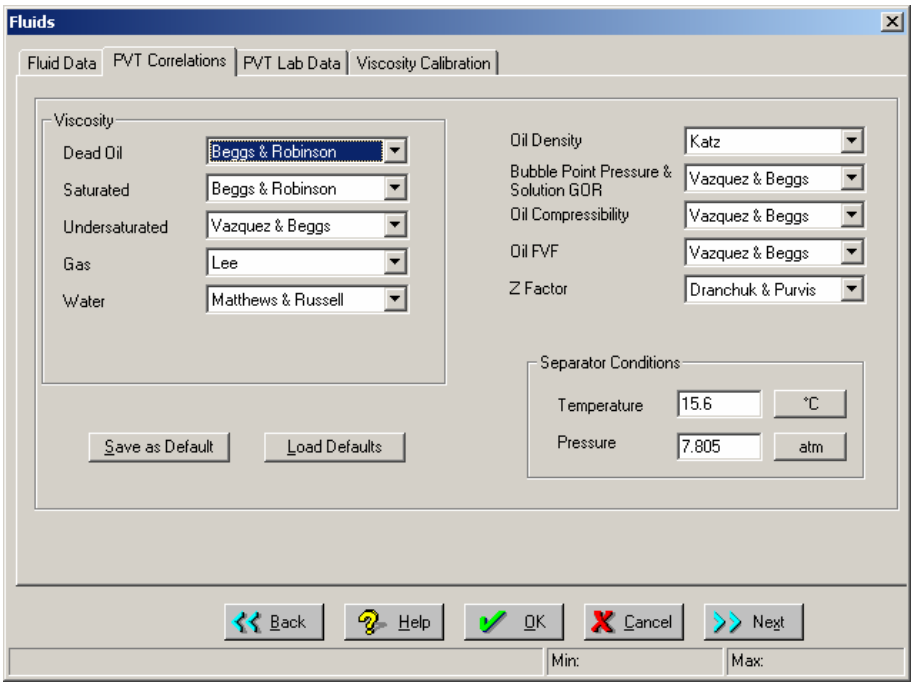


Figure 6.7 PVT Correlations Dialog Box [10]

6.3.3 PVT Lab Data

PVT Lab Data are used to adjust calculated properties using the selected PVT correlations. Figure 6.8 shows the PVT Lab Data Dialog Box [2].

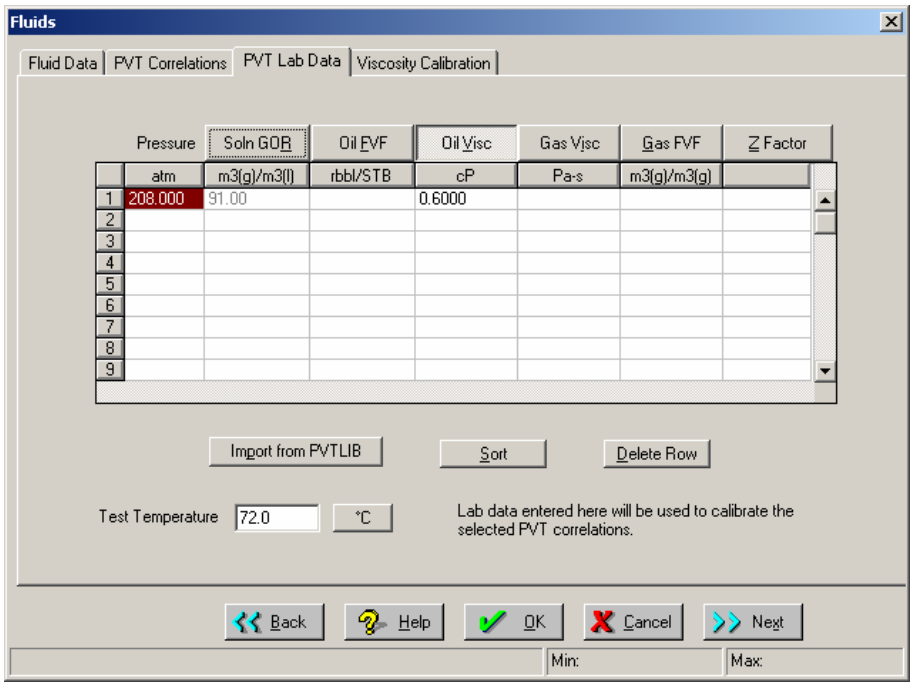


Figure 6.8 PVT Lab Data Dialog Box [10]

6.3.4 Viscosity Calibration

From the Viscosity Calibration dialog box you will use Viscosity Calibration data to calibrate the calculated viscosity with the selected viscosity correlations, and enter and edit measured viscosity data for either dead or saturated oil. Figure 6.9 shows the Viscosity Calibration data Dialog Box [2].

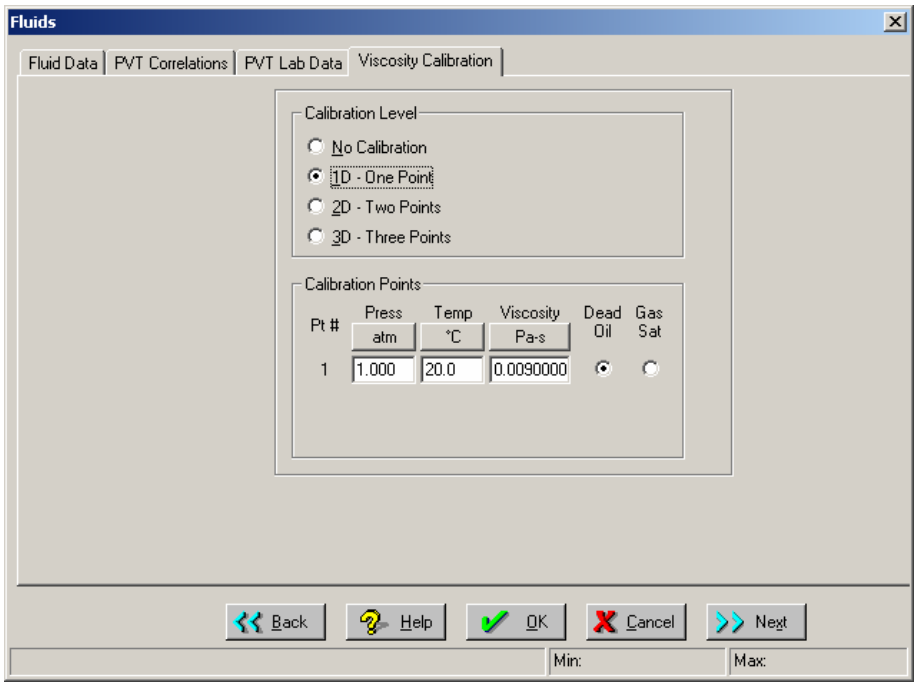


Figure 6.9 Viscosity Calibration Data Dialog Box [10]

6.4 INFLOW

The Inflow dialog box is used to determine the Performance Method and set variables for that method and to plot and evaluate the Inflow Performance curve (IPR). Figure 6.10 shows the Inflow Dialog Box.

The contents of the Inflow Data dialog box depends on the Performance Method selected. One of the following performance methods can be selected from the drop-down list box [2]:

- Productivity Index
- Vogel
- Vogel Corrected for Water Cut
- Import IPR Data from a File
- Pump Intake Pressure

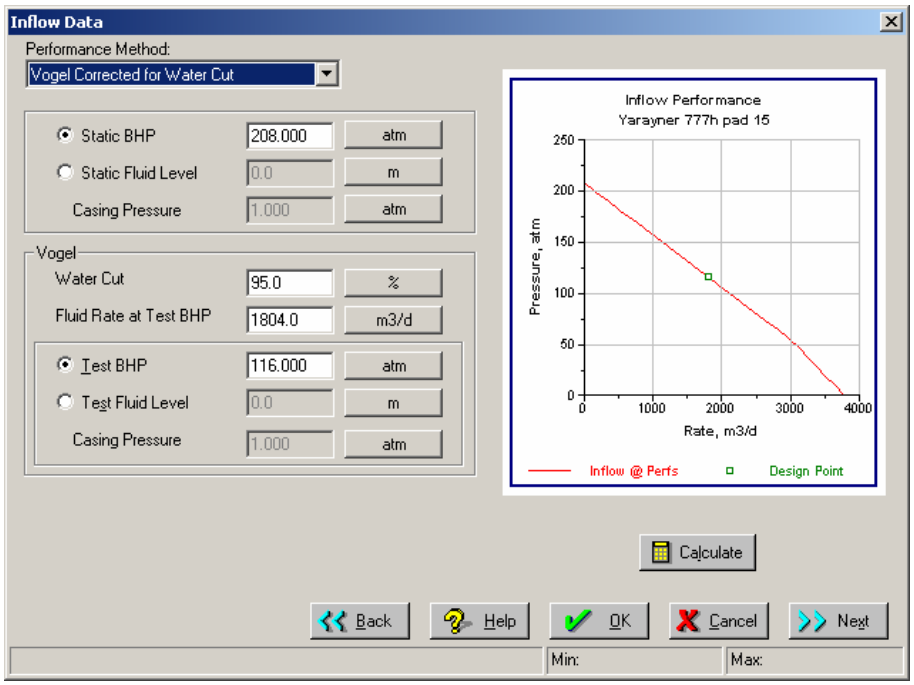


Figure 6.10 Inflow Dialog Box [10]

6.5 PRESSURES/RATES

The Pressures/Rates dialog box is the starting point to set conditions for design or analysis. The available data input fields vary for design and analysis. When an option of what to solve for is chosen, SubPUMP calculates the remaining data. It is recommended to solve for Pump Intake Conditions. When solving for Total Fluid Rate or Pump Depth, it is recommended to base calculation on Intake Pressure. Specify the conditions of the pump at full production and depth.

A new field has been added to correct for Pump Viscosity. Acorrection viscosity can be selected to have SubPUMP compensate in calculations. Pump Viscosity Correction allows the choice of Fluid, Emulsion, Oil Only, and Water Only. Fluid is considered to be all fluids including water and gas. Emulsion considers the various levels of viscosity associated with emulsion. Figure 6.11 shows the Pressures/Rates Dialog Box [2].

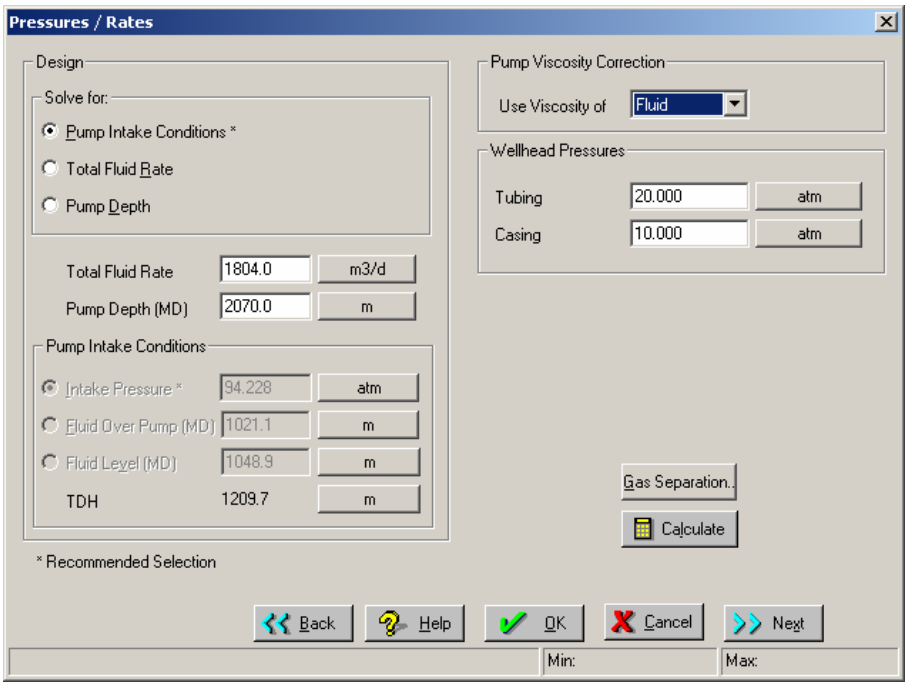


Figure 6.11 Pressures/Rates Dialog Box [10]

Based on the data entered, SubPUMP produces a list of pumps suitable for the reservoir input and target output. The user can choose one pump from the list. After choosing the pump, the user can select one or more graphs to display performance characteristics. The user can choose to have the number of pump stages calculated internally or can designate the number of pump stages with or without regard to the types of housings available for the pump. After selecting a pump the user can choose a motor to power the pump. Figure 6.12 shows the Equipment Selection Dialog Box [2].

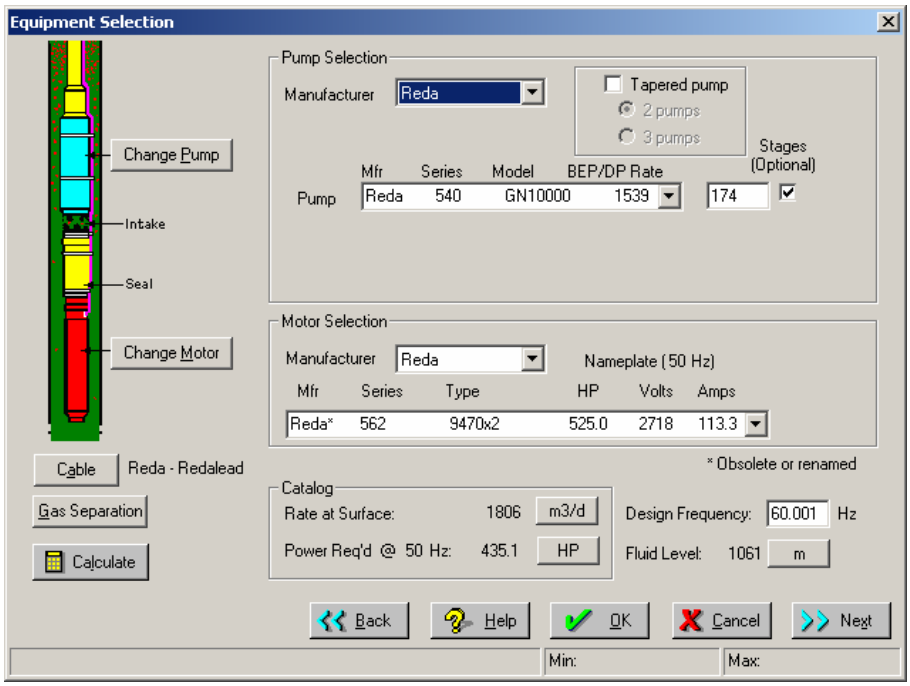


Figure 6.12 Equipment Selection Dialog Box [10]

The list includes motors within the power requirements of the pump. The list can also be adjusted for power losses due to slippage. The proper motor protector can also be evaluated. With a pump and motor the user can evaluate several cable sizes. Cost calculators built into the Cable function allows to figure monthly operating costs.

To analyze the performance of an existing system, select Analysis from Mode Selection. Enter the required data for Wellbore, Fluid, and Inflow (similar to the Design process). Enter the information for frequency and rate. In the equipment dialog box, select the pump, motor, and other components of the existing ESP system. Based on the data entered, SubPUMP calculates the operating rate and horsepower.

CHAPTER 7

ELECTRICAL SUBMERSIBLE SYSTEM DESIGN

SubPUMP software is developed by IHS energy is a registered program used by Schlumberger for electrical submersible pump applications. SubPUMP is a graphical tool to design an electrical submersible pump application for current well conditions with optimum performance.

In this chapter the procedure used for the design of the ESP systems are presented. The data of Y-field was taken from SIBNEFT. This is a new field operated by SIBNEFT and drilling activities are still continuing on this field.

7.1 INPUT DATA

In ESP system design reliable well data is very important. Changes in the data can effect the result significantly. While starting the design procedure it has to be known that enough well data is available.

In the following, the input data of an ESP system on Y-1 well is given in detail. Subpump program is used to evaluate these data.

In table 7.1 input tubing and casing data that SubPUMP uses are shown. As these study is focused on directional wells; directional survey results are needed to be given in to the program too. These directional survey results are given in table 7.2.

Table 7.1 Casing and tubing data for Y-1 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing: 1	101.60	16.37	88.29	0.016510	2070.0	
Casing: 1	177.80	38.69	159.41	0.016510	3195.0	0.0
Casing: 2	114.30	20.09	99.57	0.016510	3738.0	3155.0

Table 7.2 Directional survey results

No.	MD (m)	TVD (m)
1	500	500
2	700	696.1
3	1000	979.3
4	1340	1305.5
5	1634	1555.3
6	1804.1	1703.2
7	2000.1	1858.6
8	2039	1881.8
9	2062.9	1894.9
10	2079.5	1904.1
11	2116.8	1925
12	2136.2	1935.8
13	2145.3	1940.6
14	2203.9	1966.3
15	2300.8	1989.5
16	2407.5	2003.6
17	2504.4	2017
18	2601.2	2030.9
19	2708.3	2046.2
20	2746.8	2050.9
21	3067.2	2080.2
22	3190	2086.1
23	3195	2086.2
24	3298.4	2090
25	3763.5	2087.7

To describe the well various other data is required. Pump setting depths and TVD values are given by the client in this project. The other well data are also shown in table 7.3.

Table 7.3 Reservoir and production data for Y-1 well

Pump Depth, m	2070
Top of Perf. (Datum) Depth, m	3195
Bottom Hole Temp, °C	72
Wellhead Temp, °C	20
Pump Depth, m	2070
Oil Gravity, g/cc	0.830
SG Gas	0.800
Water Cut, %	95.0
Water Gravity	1.016
Bubble Point	
Bubble Pt Pressure, atm	95.300
GOR, m3(g)/m3(l)	104.11
Gas Impurities	
CO_2, %	0.0
H_2S, %	0.0
N_2, %	0.0
Outflow Correlation Method	Fancher & Brown [25]

The PVT correlations used and the PVT data are given in the tables 7.4 and 7.5 respectively.

Table 7.4 PVT Correlations Data

Oil Viscosity, (Dead)	Beggs & Robinson [32]
Oil Viscosity, (Saturated)	Beggs & Robinson [32]
Oil Viscosity, (UnSaturated)	Vasquez & Beggs [33]
Gas Viscosity	Lee [34]
Water Viscosity	Matthews & Russell
Oil Formation Volume Factor	Vasquez & Beggs [33]
Oil Density	Katz [40]
Z-Factor	Dranchuk, Purvis [35]
Oil Isothermal Compressibility	Vasquez & Beggs [33]
Water Isothermal Compressibility	Meehan [36]
Solution Gas/Oil Ratio	Vasquez & Beggs [33]
Bubble Point Pressure	Vasquez & Beggs [33]
Water Density	Beggs [37]
Gas Density	Beggs [37]
Oil Surface Tension Correlation	Baker and Swerdloff [38]
Water Surface Tension Correlation	Hough [39]

Table 7.5 PVT Lab Data

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
72.0	208.000	0.6000

Any change in the depth, pressure and the temperature values will also effect the viscosity. The SubPUMP program needs at least one reference point for oil viscosity calibration. Table 7.6 represents the described calibration point and calibration factor calculated by Subpump for the well Y-1

Table 7.6 Viscosity Calibration Data

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	1.000	20.0	0.009000	Dead	0.0187674	0.480

Inflow method can be selected manually and total test rate should be entered for calculation of productivity index. In table 7.7 inflow method and inflow data is shown.

Table 7.7 Inflow Data

Calculation Method	**Vogel Corrected for Water Cut**
Test Flow Rate, m^3/d	1804.0
Test BHP, atm	116.000
Flow Fld. Level, m	0.0
Flow Csg. Pressure, atm	1.000
Static BHP, atm	208.000

After completely describing the well the program needs at least two of total fluid rate, pump intake pressure or pump setting depth. These two inputs are used to calculate other parameters by SubPUMP. Table 7.8 shows these pressure and rate data.

Table 7.8 Pressure/Rate

Pressure/Rate	**Solve For Pump Intake Conditions**
Total Fluid Rate, m^3/d	1804.0
Pump Depth, m	2070.0
Flowline Surface Pressure, atm	20.000
Casing Surface Pressure, atm	10.000

7.2 CALCULATIONS AND GRAPHS

According to the Input data entered in the section 7.1 SubPUMP calculates various data and draws the graphs.

MD, TVD data pairs with angles are calculated by SubPUMP as shown in table 7.9. And the graph showing the vertical depth vs. distance and the pump setting point is plotted in figure 7.1

Table 7.9 Directional Survey Angle calculation

No.	MD (m)	TVD (m)	Angle (Deg)
1	500	500	11.3
2	700	696.1	19.3
3	1000	979.3	16.4
4	1340	1305.5	31.8
5	1634	1555.3	29.6
6	1804.1	1703.2	37.5
7	2000.1	1858.6	53.4
8	2039	1881.8	56.7
9	2062.9	1894.9	56.2
10	2079.5	1904.1	56
11	2116.8	1925	56.2
12	2136.2	1935.8	57.8
13	2145.3	1940.6	64.1
14	2203.9	1966.3	76.1
15	2300.8	1989.5	82.4
16	2407.5	2003.6	82
17	2504.4	2017	81.7
18	2601.2	2030.9	81.8
19	2708.3	2046.2	83
20	2746.8	2050.9	84.8
21	3067.2	2080.2	87.3
22	3190	2086.1	88.9
23	3195	2086.2	87.9
24	3298.4	2090	90.3
25	3763.5	2087.7	0

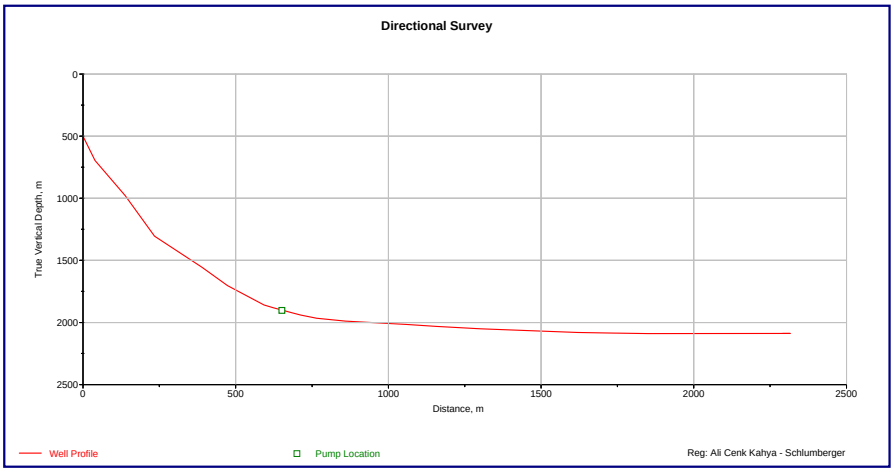


Figure 7.1 Directional survey

The IPR curve is plotted showing both the inflow at the perforations and inflow at the pump. The design point is shown also on the graph in the figure 7.2

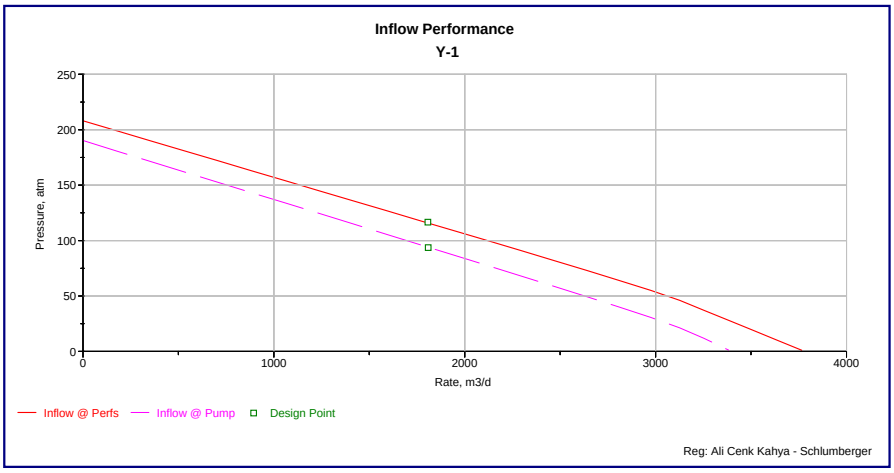


Figure 7.2 IPR Curve

According to the input data the free gas available at the pump and free gas in to the pump is calculaeted. Table 7.9 shows these data.

Table 7.9 Gas Separator Performance

Packer Installed	No
Free Gas Avail. at Pump, %	0.69
Natural Gas Separation, %	16.6
Free Gas into Pump, %	0.25
Gas Separator Installed	Yes
Gas Separator Efficiency, %	56.00

The program provides data to create a well system curve. Table 7.10 is the well system curve detail for well Y-1, it can be seen from the table if the design conditions were appropriate or not. The last row of the table includes the design condition which was the 1804 m^3/d total oil and water production rate design conditions desired to be below pump off limit. Pump off is the condition in which the fluid comes to the pump intake depth and fluid production decrease at that point fluid velocity is not enough to cool the motor. And this can result in motor burn.

Table 7.10 Well System Curve Detail

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m^3/d	Avg. Pump Rate O+W+G m^3/d	Pumping Fluid Level m
1	6629.45	6362.82	266.63	32.5	33.4	41.8
2	6685.49	5634.31	1051.18	434.7	446.4	264.8
3	6748.7	4908.43	1840.27	836.9	859.4	487.6
4	6850.33	4187.52	2662.8	1239.1	1272.5	714.5
5	7036.24	3457.59	3578.65	1641.4	1685.5	953.3
6	7306.66	2737.87	4568.8	2043.6	2098.5	1188.9
7	7667.15	2021.07	5646.08	2445.8	2511.6	1437.7
8	8182.5	1290.36	6892.13	2848	2924.6	1711.8
PumpOff	9580.34	431.06	9149.28	3250.2	3337.6	2067.2
Design	7132.31	3163.45	3968.85	1804.0	1852.5	1048.9

Table 7.11 shows the theoretical pump data and using the total rate at surface represented in this table pump unit was selected. Selections of equipments start with pump selection. A list of pumps matching the design criteria is used for choosing the most suitable pump and number of stages is calculated. Pump list includes the maximum and minimum recommended rates of the pumps. While selecting the pump unit, it is desired to find to closest rate peak efficiency to the theoretical rate.

Table 7.11 Theoretical Pump Performance

	Intake	Discharge	Surface
Oil Rate, m^3/d	109.7	109.2	90.3
Gas Rate through Pump, m^3/d	4.7	0.0	N/A
Gas Rate from Casing, m^3/d	8.2	N/A	N/A
Total Gas Rate, m^3/d	N/A	N/A	9401.6
Free Gas Percent, %	0.25	0.00	N/A
Water Rate, Bbl/D	11000.43	10946.12	10791.56
Total Liquid Rate, m^3/d	1858.7	1849.5	1806.0
Pressure, atm	94.120	210.948	20.000
Specific Gravity Liquid, wtr=1	0.98	0.99	N/A
Specific Gravity Mixture, wtr=1	0.98	0.99	N/A
Liquid Density, g/cc	0.981	0.985	N/A
Mixture Density, g/cc	0.979	0.985	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m^3 (g)/ m^3 (l)	62.15	66.21	N/A
Solution GWR, m^3 (g)/ m^3 (l)	1.47	8.57	N/A
Liquid FVF, res/surf	1.03	1.02	N/A
Mixture FVF, res/surf	1.03	1.02	N/A
Gas Deviation Factor	0.820	0.804	N/A

REDA 540 series GN10000 pump is selected from the database as it has a rate of 1539 peak efficiency which is the closest rate to the theoretical one. In table 7.12 and 7.13 power and stage data is shown. In figure 7.3 the pump performance curve for the selected pump is given. As it can be seen from the graph there are different performance curves for the different frequencies. In this study all the wells will be working with Variable speed Drives. So the most suitable frequency for our design can be selected from this graph and it seems to be 60 hz. At 60 hz the pump will be giving a TDH of 3973 ft and production rate of 1806 m^3/d. And this is within the optimum range of the selected unit

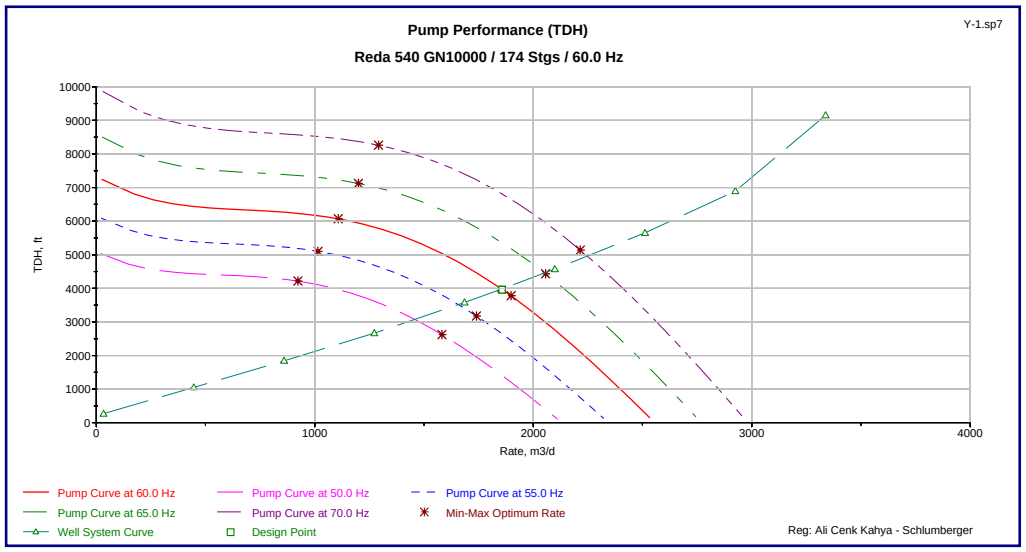


Figure 7.3 Pump performance curve for GN10000 174 stages

Table 7.12 Pump Data

Manufacturer	Reda
Series	540
Model	GN10000
Minimum Recommended Rate, m^3/d	1107.4**
Maximum Recommended Rate, m^3/d	1898.3**
Frequency, Hz	60.0
Number of Stages,	174

** Corrected for frequency and viscosity

Table 7.13 Pump Data

	Design	174 Stages
Total Dynamic Head (TDH), ft	3968.85	3973.04
Surface Rate (O+W), m^3/d	1804.0	1806.0
Avg. Pump Rate (O+G+W), m^3/d	N/A	1854.6
Pump Intake Pressure, atm	94.228	94.120
Operating Power, HP	N/A	522.1
Pump Efficiency, %	N/A	65.2

A list of motors that will operate the chosen pump is available in the SubPUMP program. Horsepower, voltage, amperage and temperature around the motor are calculated in this step. Table 7.14 shows the motor information selected for the Y-1 well. The protector data is also given in table 7.15.

Table 7.14 Motor Data

Manufacturer	Reda
Series	562
Name Plate Power, HP	525.0
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	2718.35
Name Plate Current, Amps	113.3
Design Frequency, Hz	60.0
Operating Motor Load, HP	522.1
Operating Motor Load,	82.88
Operating Speed, RPM	3495
Operating Current, Amps	97.1
Operating Voltage, Volts	3262.07
Fluid Velocity, ft/sec	17.346
Well Fluid Temperature, °C	67.3

Table 7.15 Protector Data

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BSLSBSL HL
Bearing Cap., kg	6803.9

Last part of the system design is the power cable. A list of cables can be seen in the program. According to the voltage requirements and well conditions the proper cable can be selected.

Table 7.16 Cable Data

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2170.0

CHAPTER 8

RESULTS AND DISCUSSION

8.1 FIELD AND WELL DATA

Field and well data used in this study are obtained from production department of SIBNEFT. Some of the reservoir properties and production data are represented in Table 8.1. According to these data the equipment given in Table 8.2 is selected from the SIBNEFT inventory. SIBNEFT orders various sizes of ESP pumps for its inventory and then suitable pumps for the well conditions are selected for each application. As all these pumps will be running on variable speed drives, it is possible to obtain the required flow rates. The flow rates and operating frequencies are given in Table 8.3.

Table 8.1 Input Data

	Y-1	Y-2	Y-3	Y-4	Y-5	Y-6	Y-7	Y-8	Y-9	Y-10
Top of Perf. (Datum) Depth, m	3195	2630	2561	2572	2665	2102	2144	2177	1806	2244
Pump Depth, m	2070	2010	2194	2500	2290	1650	2000	1908	1740	1920
Bottom Hole Temp, °C	72	72	74	68	72	51	51	61	51	72
Oil Gravity, API	39.0	39.2	41.1	36.8	41.1	32.7	32.7	37.6	32.7	37.6
Water Cut, %	95	45	56	15	25	93	80	15	90	94
Water Gravity	1.016	1.016	1.016	1.004	1.016	1.015	1.015	1.015	1.015	1.015
Bubble Point Pressure, atm	95.3	113.0	146.3	94.0	146.0	110.0	110.0	107.0	110.0	111.8
GOR, $m^3(g)/m^3(l)$	104.11	64.84	108.11	54.68	127.74	54.75	54.86	54.55	46.25	54.79

Table 8.2 Selected Equipment

	Pump Selected	Pump Stages	Motor Selected	Motor HP	Protector Selected	Protector Type	Cable Selected
Y-1	REDA 540 GN10000	174	REDA 562	525	REDA 540	BSLSBSL - HL	Redalead AWG 2, Flat, Stranded
Y-2	REDA 540 GN10000	174	REDA 562	630	REDA 540	BPBSL-HL	Redalead AWG 2, Flat, Stranded
Y-3	REDA 540 GN10000	232	REDA 562	600	REDA 540	BSLSBSL -HL	Redalead AWG 2, Flat, Stranded
Y-4	REDA 540 GN5200	204	REDA 456	300	REDA 540	LSBPB-HL	Redalead AWG 4, Flat, Solid
Y-5	REDA 538 SN8500	219	REDA 562	600	REDA 540	LSBPBSL -HL	Redalead AWG 2, Flat, Stranded
Y-6	REDA 562 HN21000	85	REDA 562	900	REDA 540	BSLSBSL -HL	Redalead AWG 2, Round, Solid
Y-7	REDA 540 GN10000	116	REDA 562	630	REDA 540	BSLSBSL -HL	Redalead AWG 2, Flat, Solid
Y-8	REDA 538 S5000N	207	REDA 562	500	REDA 540	BPBSL-HL	Redalead AWG 2, Flat, Stranded
Y-9	REDA 538 SN8500	189	REDA 562	525	REDA 540	BPBSL-HL	Redalead AWG 2, Flat, Stranded
Y-10	REDA 538 SN8500	189	REDA 562	391.6	REDA 540	BPBSL-HL	Redalead AWG 2, Flat, Stranded

Table 8.3 Recommended Equipment

	Pump Selected	Pump Stages	Motor Selected	Motor HP	Protector Selected	Protector Type	Cable Selected
Y-2	REDA 540 GN5200	260	REDA 562	378	REDA 540	BPBSL-HL	Redalead AWG 2, Flat, Stranded
Y-5	REDA 540 GN 10000	138	REDA 540	350	REDA 540	LSBPBSL -HL	Redalead AWG 2, Flat, Stranded
Y-7	REDA 562 HN 13500	90	REDA 540	675	REDA 540	BSLSBSL -HL	Redalead AWG 2, Flat, Solid
Y-8	REDA 540 GN 5600	195	REDA 562	580	REDA 540	BPBSL-HL	Redalead AWG 2, Flat, Stranded

Table 8.4 Pump Data

	Test flow Rate, m^3/d	Design Flow Rate, m^3/d	Pump Stages	Operating Frequency, Hz	Design TDH, ft	Pump TDH, ft	Pump Efficiency, %
Y-1	1804	1806	174	60	3969	3973	65.2
Y-2	680	676	174	60	6774	6671	62.2
Y-2 (Rec.)	680	680	260	54	6862	6874	77.9
Y-3	998	998	232	58	7387	7407	70.2
Y-4	555	555	204	50	5049	5079	73.2
Y-5	1100	1112	219	49	2521	2625	47.0
Y-5 (Rec.)	1100	1100	138	52	2505	2507	51.5
Y-6	3376	3376	85	55	2877	2877	59.9
Y-7	2074	2056	116	66	2024	2355	59.5
Y-7 (Rec.)	2074	2178	90	53	1972	2206	67.2
Y-8	690	585	207	57	6260	5558	41.5
Y-8 (Rec.)	690	695	195	69	6311	6367	43.0
Y-9	1517	1517	189	56	4723	4720	68.0
Y-10	1047	1047	189	50	4375	4376	63.0

8.2 WELL ANALYSIS

The Pump Performance graph depicts the TDH of the pump (outflow) curve and well system (inflow) curve plotted as TDH vs. Liquid plus Gas in average pump bbls/day. The pump curve is generated from the pump performance curve with enough stages to meet or exceed the total fluid rate corrected for frequency, viscosity effects, and slip adjustment if desired. A small asterisk on the pump curve depicts the minimum and maximum rate limits for the pump at the design frequency.

The well system curve is derived from the TDH resulting from the difference between the pump intake and pump discharge head based on the tubing characteristics, back pressure, pump depth, fluid properties, and reservoir inflow performance relationship.

The intersection of these two curves gives the actual TDH and flowrate in average pump barrels for the design where the pump capacity (pump curve) meets the pump requirements (well system curve). The increase in production for this installation is

the difference in the well rate without a pump (2200 APB/day) and the intersection rate (3300 APB/day) or 1100 APB/day.

The Pump Performance curve can be generated for a variable speed drive motor (VSD) to depict various design frequencies at 5 Hz and 10 Hz intervals above and below the design Hz. The graph shows that the pump will operate at higher flowrates at higher frequencies. However, it will be outside the desired operating envelope when the motor frequency goes above 65 Hz.

8.2.1 Analysis of Y-1 Well

Inspection of pump performance curve of the Y-1 well lets us to make the following interpretations:

Actual operating rate of Y-1 is 1806 m^3/day with 174 stages and at 60 Hz. This operating rate is within the optimum efficiency range. The pump will run at 65.2 % efficiency. Although it is very close to the maximum optimum efficiency point, the flow rate is expected to decrease by time. This design is capable of giving enough flexibility for future. Figure 8.1 gives the pump performance curves of well Y-1 for several frequencies.

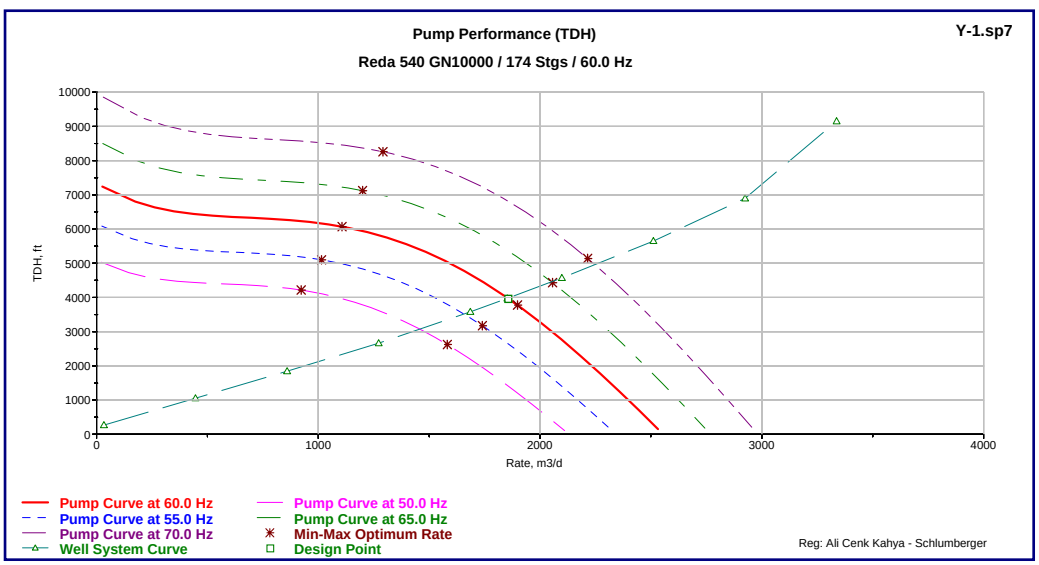


Figure 8.1 Y-1 Pump Performance Curve

8.2.2 Analysis of Y-2 Well

Inspection of pump performance curve of the Y-2 well lets us to make the following interpretations:

Actual operating rate of Y-2 is 676 m^3/day with 174 stages at 60 Hz.. This operating rate is out off the optimum efficiency range, the efficiency of the pump is 62.2 %. This pump is oversized for this well, and this design can not be accepted. Figure 8.2 gives the pump performance curves of well Y-2 for several frequencies. A new pump is selected for Y-2 well, so by this design the new flowrate is 680 m^3/day with 260 stages and at 54 Hz.. The efficiency of the pump is increased to 77.9 %. This new design is a better design for this well. In Figure 8.3 the pump performance curve for the recommended design is given.

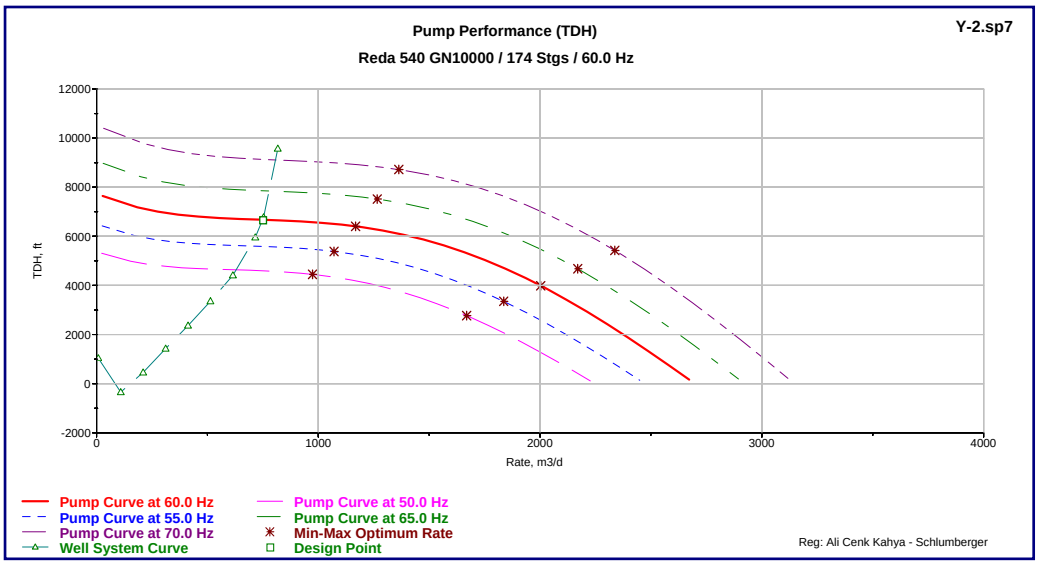


Figure 8.2 Y-2 Pump Performance Curve

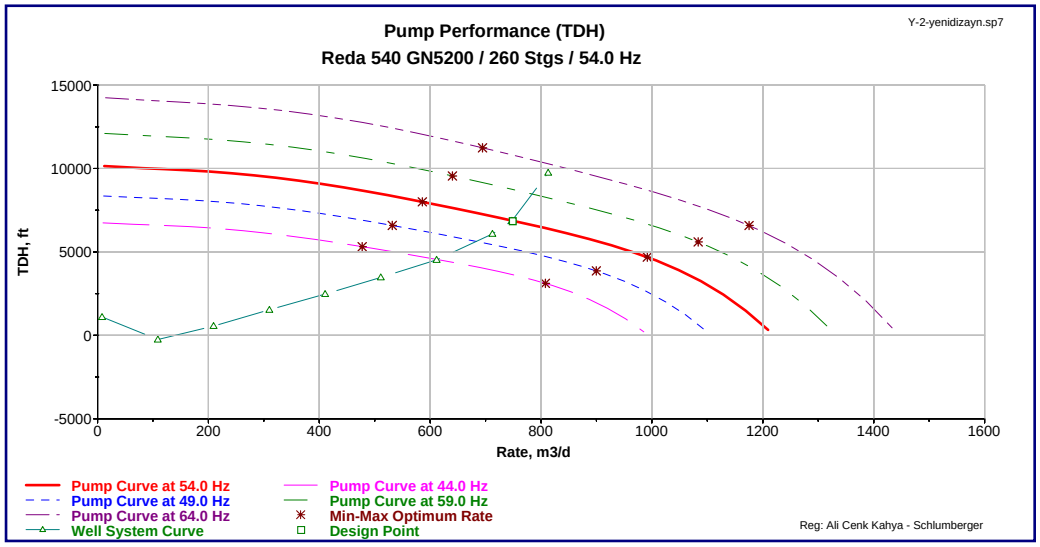


Figure 8.3 Y-2 Recommended Pump Performance Curve

8.2.3 Analysis of Y-3 Well

Inspection of pump performance curve of the Y-3 well lets us to make the following interpretations:

Actual operating rate of Y-3 is 998 m^3/day with 232 stages and at 58 Hz. This operating rate is within the optimum efficiency range. The efficiency of the pump is 70.2 %. This design is an acceptable design for this well. Figure 8.4 gives the pump performance curves of well Y-3 for several frequencies.

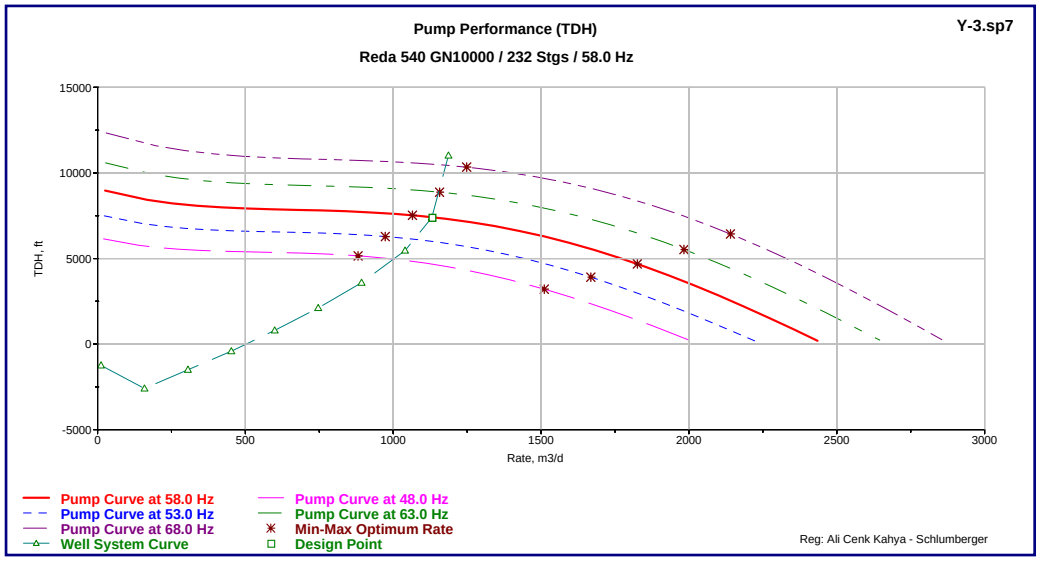


Figure 8.4 Y-3 Pump Performance Curve

8.2.4 Analysis of Y-4 Well

Inspection of pump performance curve of the Y-4 well lets us to make the following interpretations:

Actual operating rate of Y-4 is 555 m^3/day with 204 stages and at 50 Hz. This operating rate is within the optimum efficiency range. The efficiency of the pump is 73.2 %. This design is an optimum design for this well. Figure 8.5 gives the pump performance curves of well Y-4 for several frequencies.

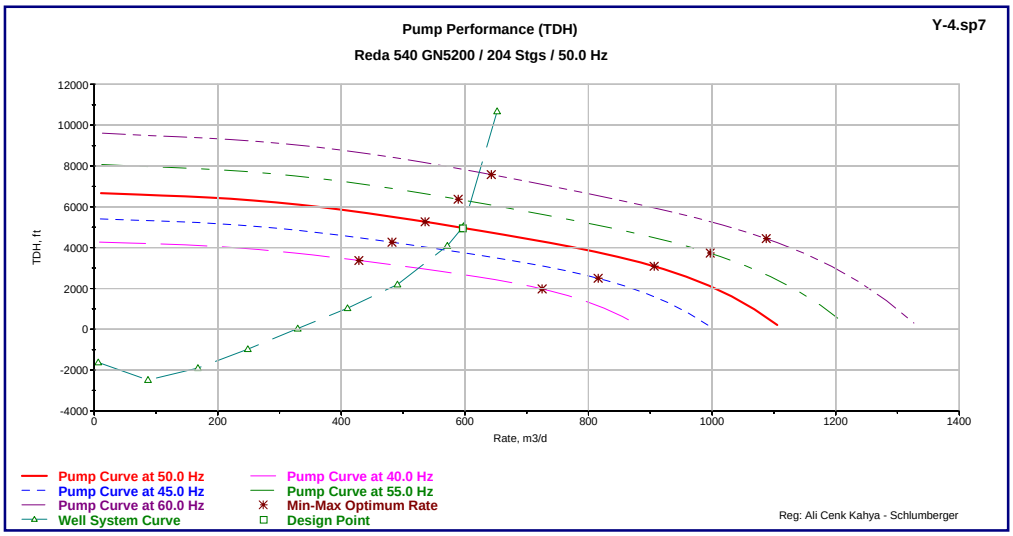


Figure 8.5 Y-4 Pump Performance Curve

8.2.5 Analysis of Y-5 Well

Inspection of pump performance curve of the Y-5 well lets us to make the following interpretations:

Actual operating rate of Y-5 is 1100 m^3/day with 219 stages and at 49 Hz. This operating rate is outside the optimum efficiency range. The efficiency of the pump is 47 %. This design is not the optimum design for this well. Figure 8.6 gives the pump performance curves of well Y-5 for several frequencies. A new design is made for this well. The flowrate is 1100 m^3/day with 138 stages at 52 Hz. The efficiency for this new design is 51.5 %. Figure 8.7 gives the pump performance curves of the new recommended design.

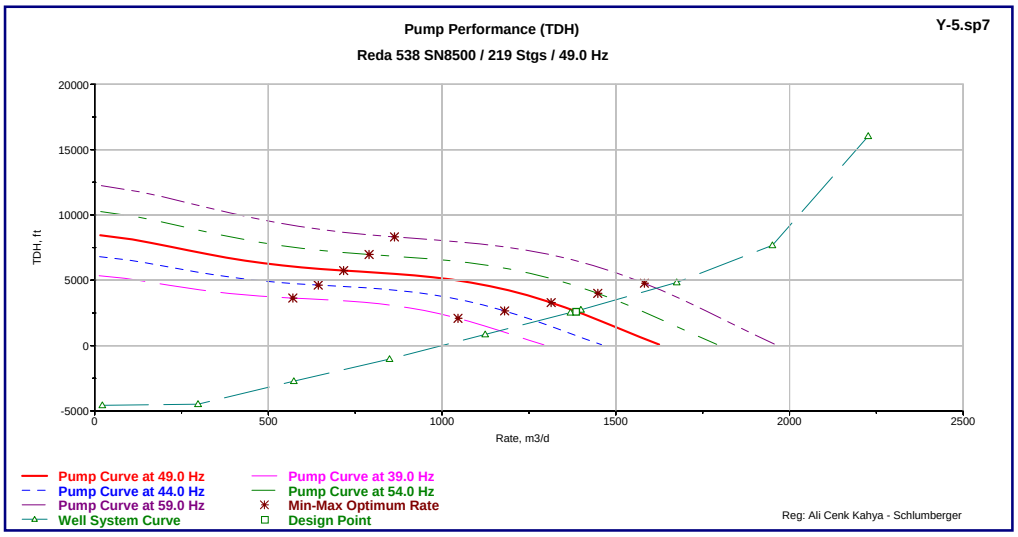


Figure 8.6 Y-5 Pump Performance Curve

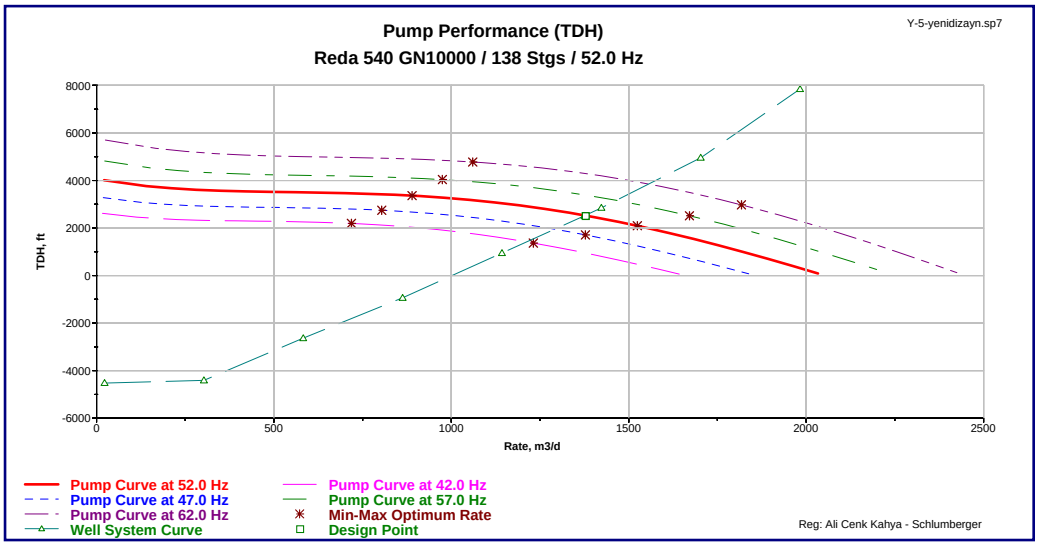


Figure 8.7 Y-5 Recommended Pump Performance Curve

8.2.6 Analysis of Y-6 Well

Inspection of pump performance curve of the Y-6 well lets us to make the following interpretations:

Actual operating rate of Y-6 is 3376 m^3/day with 85 stages and at 55 Hz. This operating rate is in the optimum efficiency range. The efficiency of the pump is 59.9 %. This design is the optimum design for this well. Figure 8.8 gives the pump performance curves of well Y-6 for several frequencies.

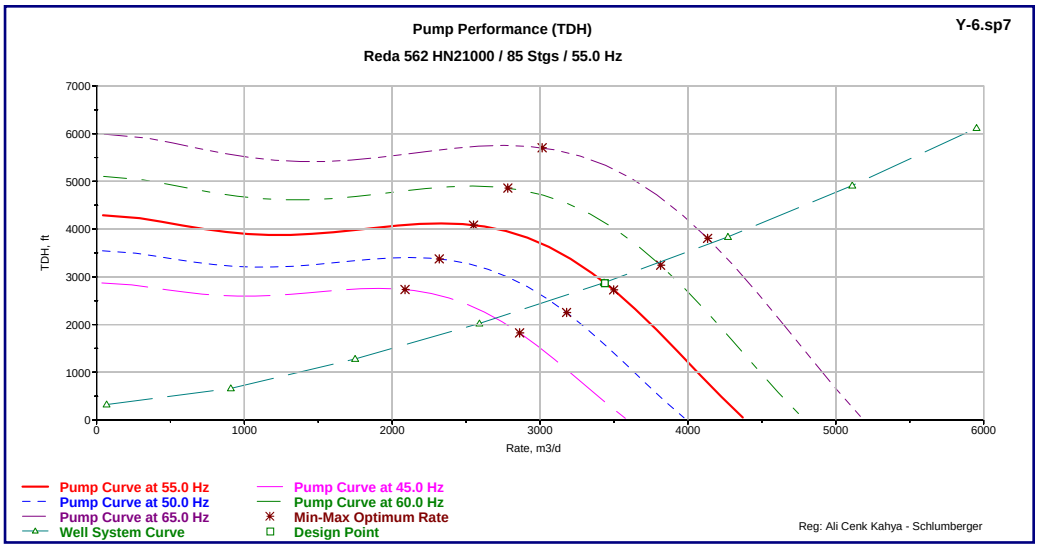


Figure 8.8 Y-6 Pump Performance Curve

8.2.7 Analysis of Y-7 Well

Inspection of pump performance curve of the Y-7 well lets us to make the following interpretations:

Actual operating rate of Y-7 is 2056 m^3/day with 116 stages and at 66 Hz. This operating rate is slightly outside the optimum efficiency range. The efficiency of the pump is 59.9 %. Figure 8.9 gives the pump performance curves of well Y-7 for several frequencies. To keep the design in optimum range, the production can be decreased by decreasing the running frequency or an alternative pump can be selected for this well. Reda 562 HN 13500 can be used for this well as an alternative, and flowrate will be 2178 m^3/day with 90 stages and at 53 Hz.. The efficiency of the pump will be 67.2%. This new design is a better alternative for this well. Figure 8.10 gives the pump performance curves of recommended design for the well Y-7.

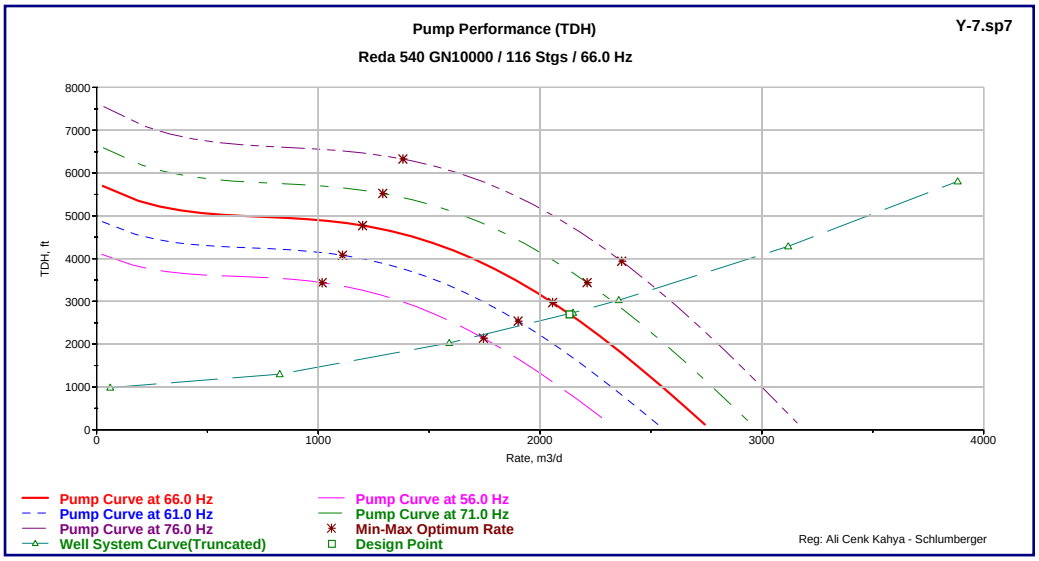


Figure 8.9 Y-7 Pump Performance Curve

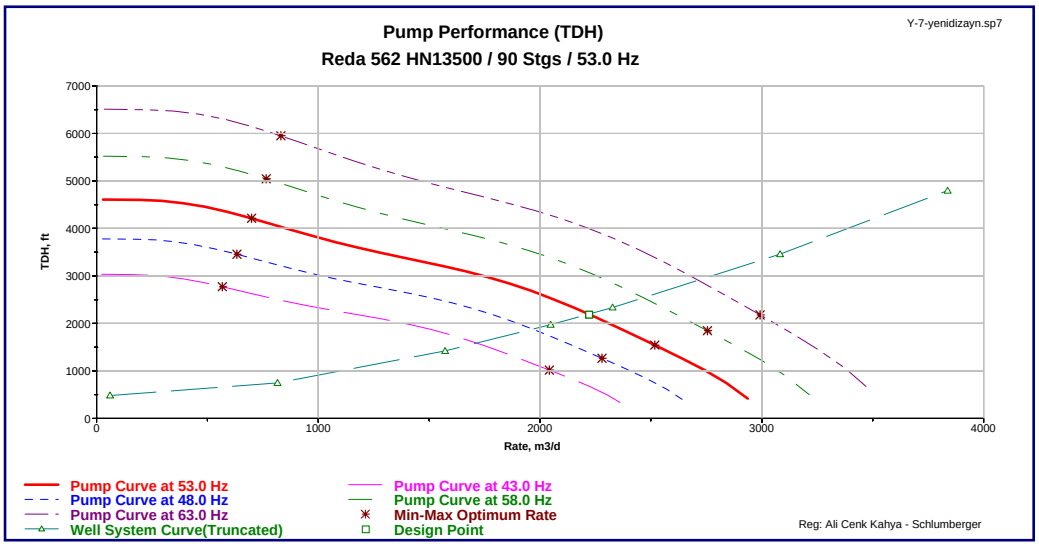


Figure 8.10 Y-7 Recommended Pump Performance Curve

8.2.8 Analysis of Y-8 Well

Inspection of pump performance curve of the Y-8 well lets us to make the following interpretations:

Actual operating rate of Y-8 is 585 m^3/day with 207 stages at 57 Hz.. This operating rate is outside the optimum efficiency range. The efficiency of the pump is 41 %. Figure 8.11 gives the pump performance curves of well Y-8 for several frequencies. To keep the design in optimum range, the production should be decreased by decreasing the running frequency or a new set of pumps should be installed. REDA 540 series GN 5600 pump is selected for this application. It has 195 stages and will be producing 695 m^3/day at 69 Hz.. Pump performance curves of the new design for well Y-8 is given in Figure 8.12.

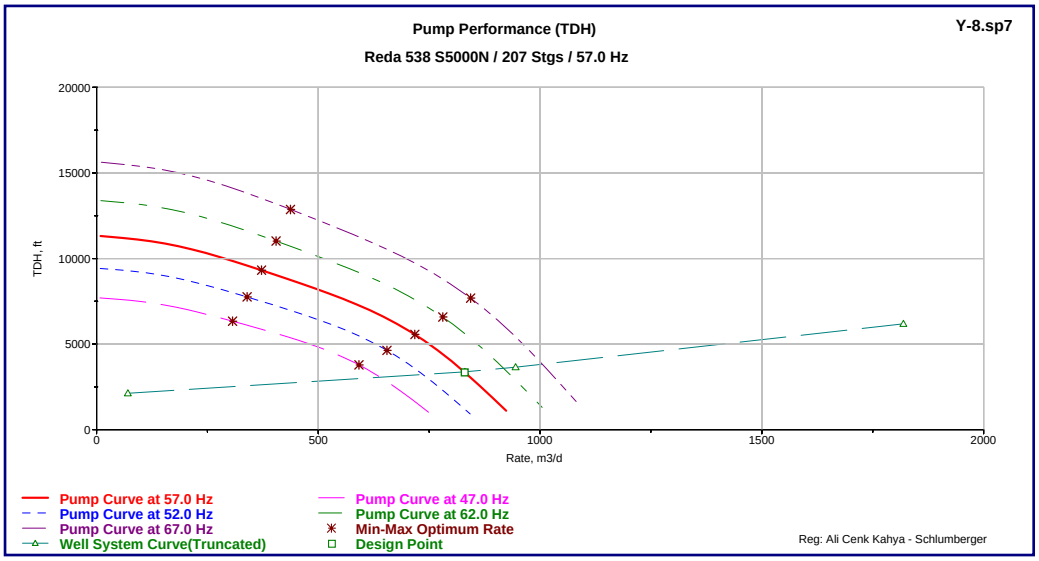


Figure 8.11 Y-8 Pump Performance Curve

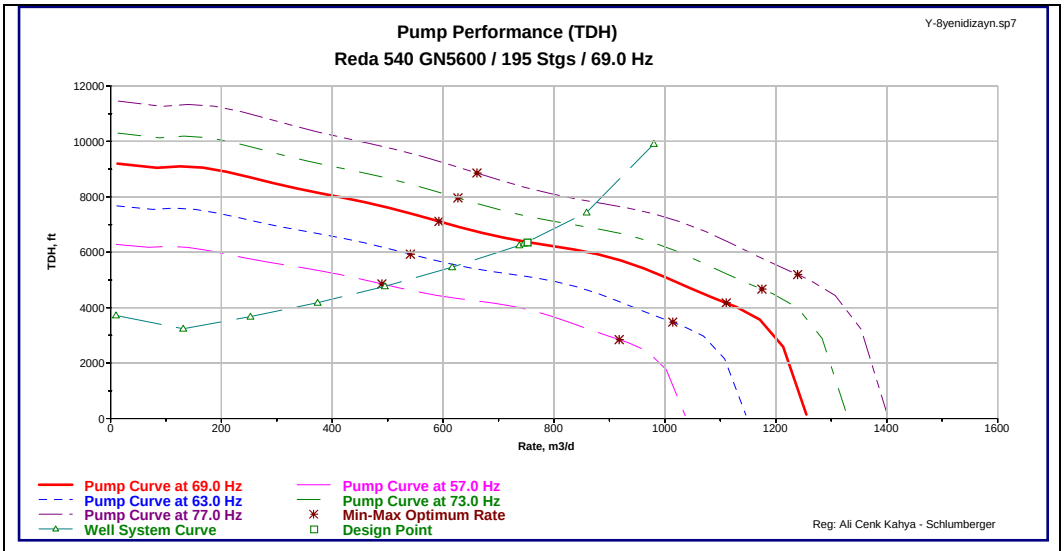


Figure 8.12 Recommended Y-8 Pump Performance Curve

8.2.9 Analysis of Y-9 Well

Inspection of pump performance curve of the Y-9 well lets us to make the following interpretations:

Actual operating rate of Y-9 is 1517 m^3/day with 189 stages and at 56 Hz. This operating rate is in the optimum efficiency range. The efficiency of the pump is 68 %. Figure 8.9 gives the pump performance curves of well Y-9 for several frequencies.

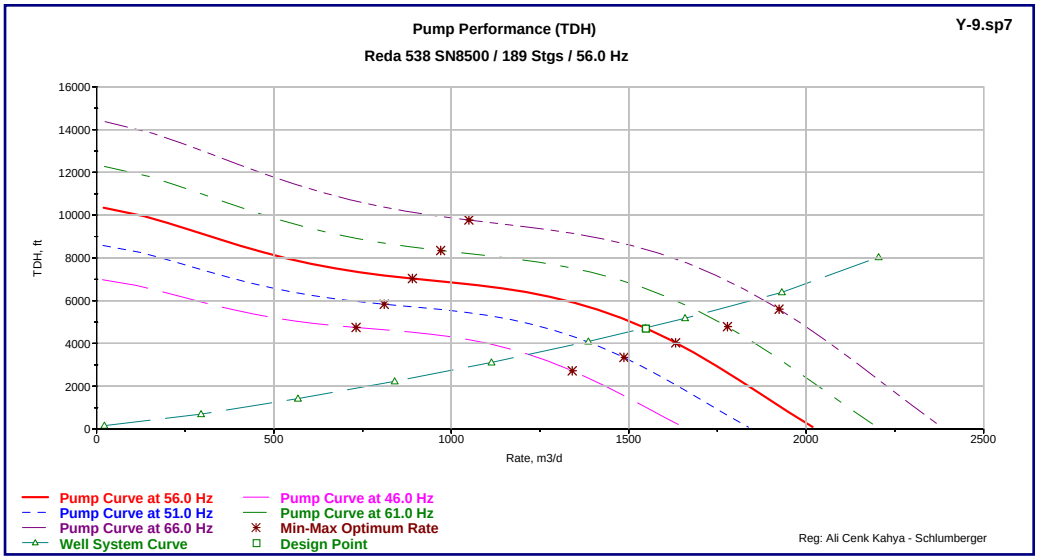


Figure 8.13 Y-9 Pump Performance Curve

8.2.10 Analysis of Y-10 Well

Inspection of pump performance curve of the Y-10 well lets us to make the following interpretations:

Actual operating rate of Y-10 is 1047 m^3/day with 189 stages and at 50 Hz. This operating rate is in the optimum efficiency range. The efficiency of the pump is 63 %. Figure 8.10 gives the pump performance curves of well Y-10 for several frequencies.

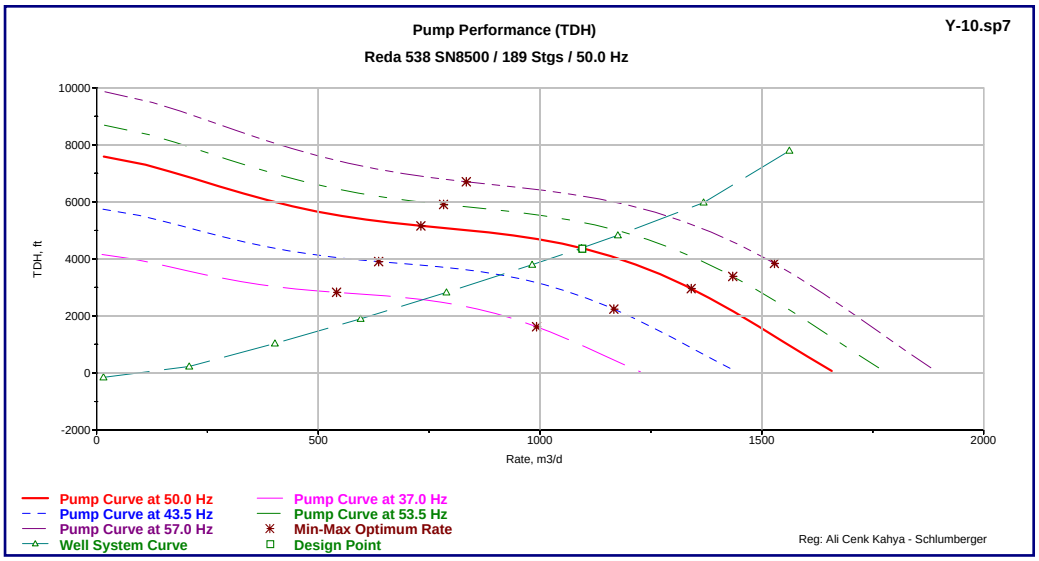


Figure 8.14 Y-10 Pump Performance Curve

CHAPTER 9

CONCLUSIONS

Electric Submersible Pumping systems are powerful methods for artificial production of wells. In this study 10 artificially producing, deviated or horizontal wells from Y-field in Western Siberia were evaluated.

A commercial software; SubPUMP, developed by IHS energy is used for the design of the ESP systems. SubPUMP is an advanced Windows™ software package for designing an efficient Electric Submersible Pumping (ESP) system and/or analyzing an existing ESP system. The program provides the user with pump, motor and other component information for the system from leading industry suppliers.

All the data used in this study is taken from SIBNEFT. The selected equipment are the available sets in SIBNEFT`s inventory. All the equipment is selected from Reda ESP systems. All of the ESP sets will be working with Variable Speed Drives. So the designs for these wells are made according the this. The required running frequencies are selected for the optimum production of the wells.

From the results it can be said that the sets selected for the wells Y-1, Y-3, Y-4, Y-6, Y-9, Y-10 are completely suitable for these wells.

The set used in Y-2 well seems to be oversized for this well. A new set of pumps is proposed for this well, for a longer runlife and stable production. Reda 540 series GN5200 seems a better alternative for this well. And the sets that are used in the wells Y-5, Y-7, Y-8 needs to work over their maximum optimum operating rates. New sets of pumps are selected for those wells too. For Y-5 well Reda 540 series GN 10000 is more suitable. For Y-7 Reda 562 HN 13500 and for Y-8 Reda 540 GN 5600 pumps were selected. As these pumps will be operating within their optimum efficiency ranges. This will give the pumps higher production rates, a longer run life and stable production.

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APPENDIX A

INFLOW PERFORMANCE RELATION CHARTS

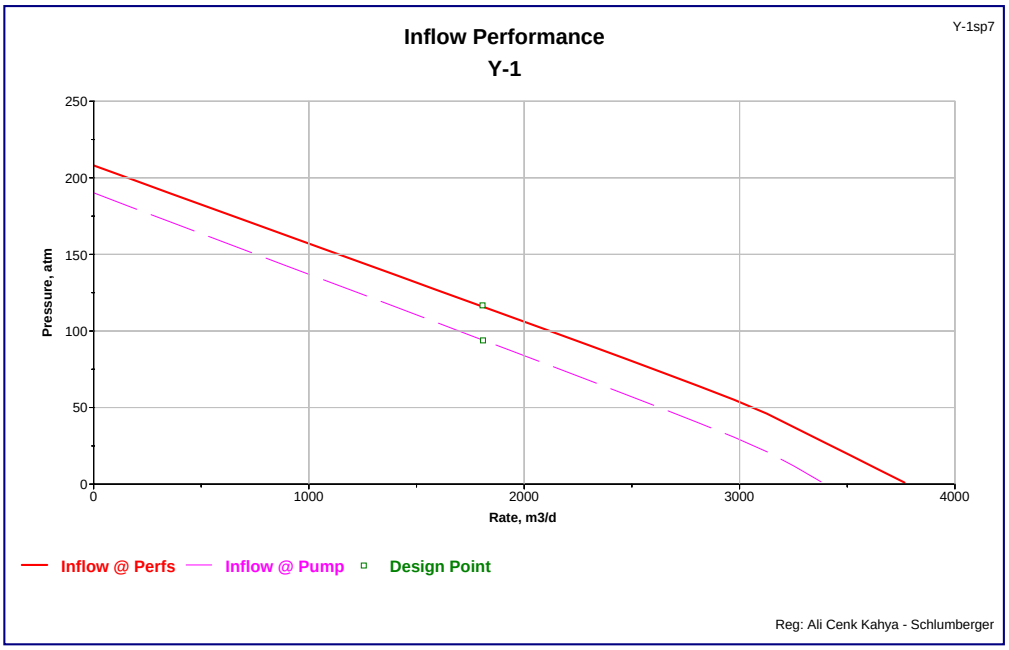

Figure A.1 Inflow performance relation of Y-1 well

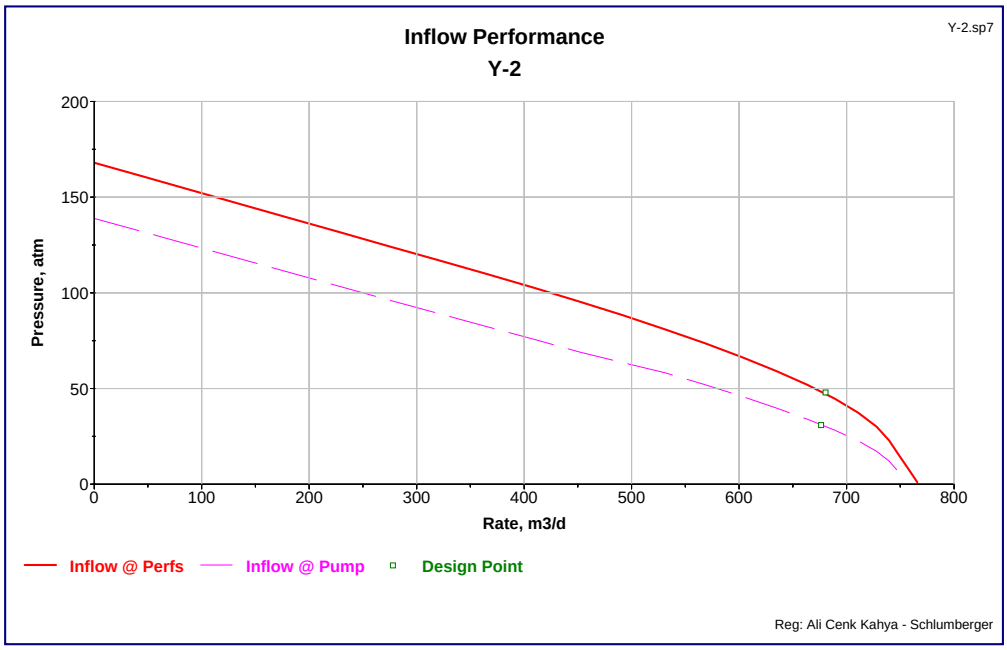

Figure A.2 Inflow performance relation of Y-2 well

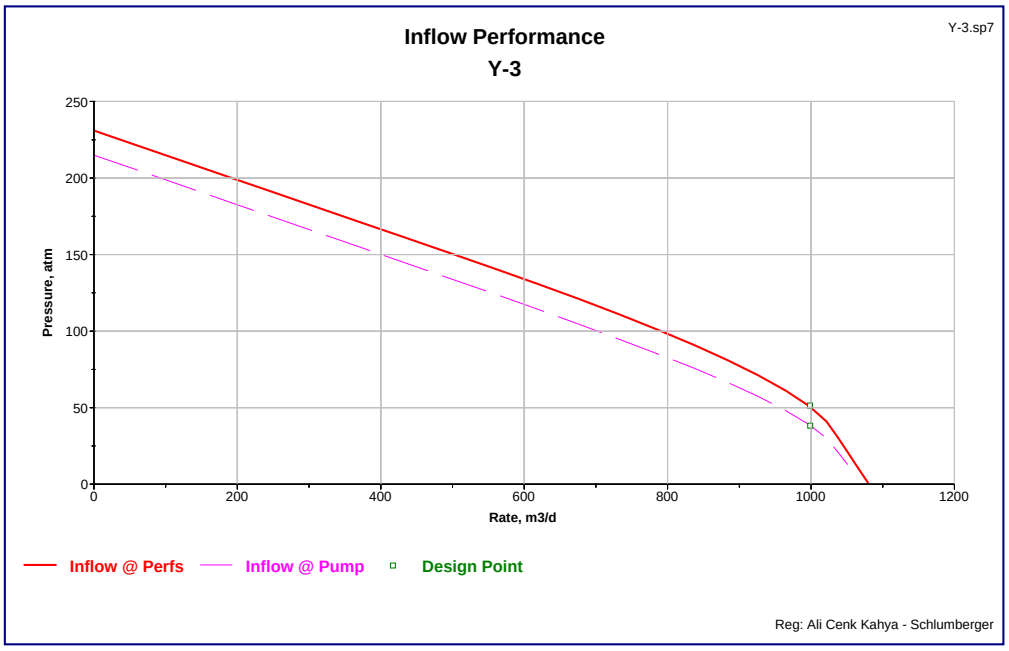

Figure A.3 Inflow performance relation of Y-3 well

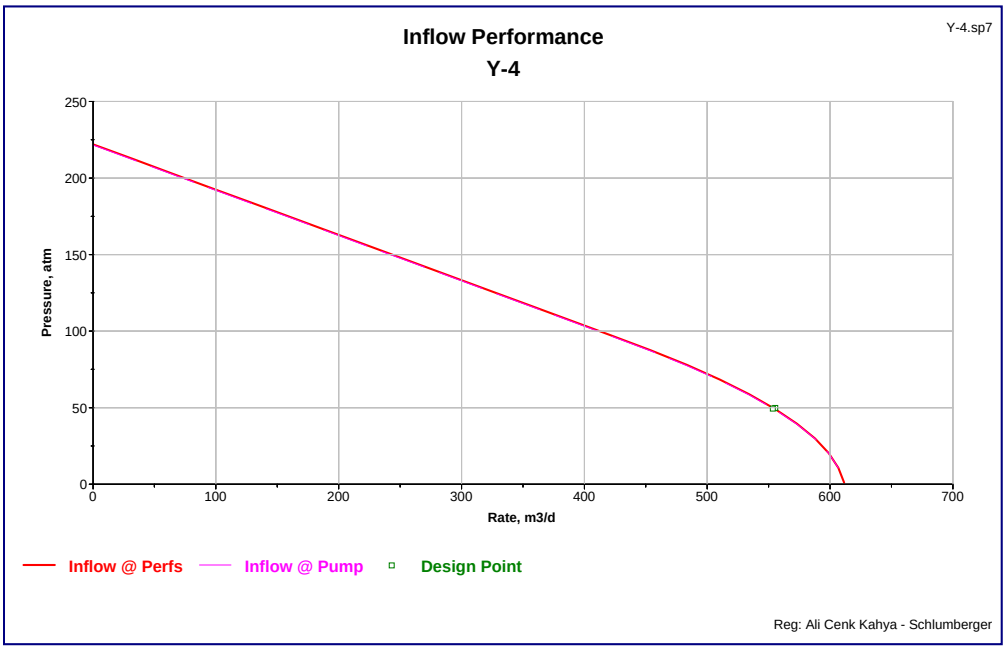

Figure A.4 Inflow performance relation of Y-4 well

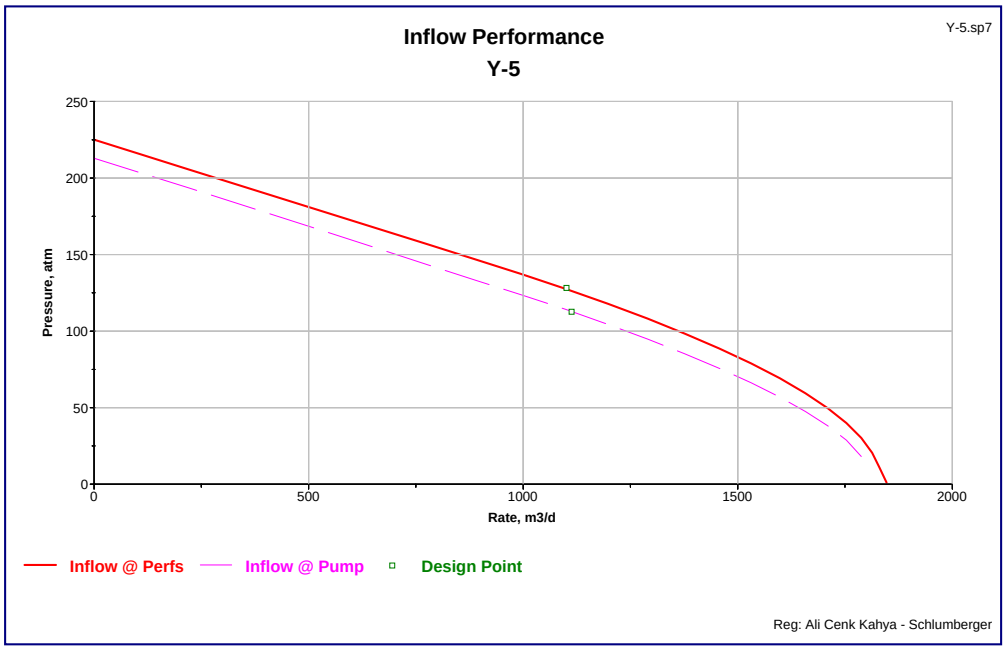

Figure A.5 Inflow performance relation of Y-5 well

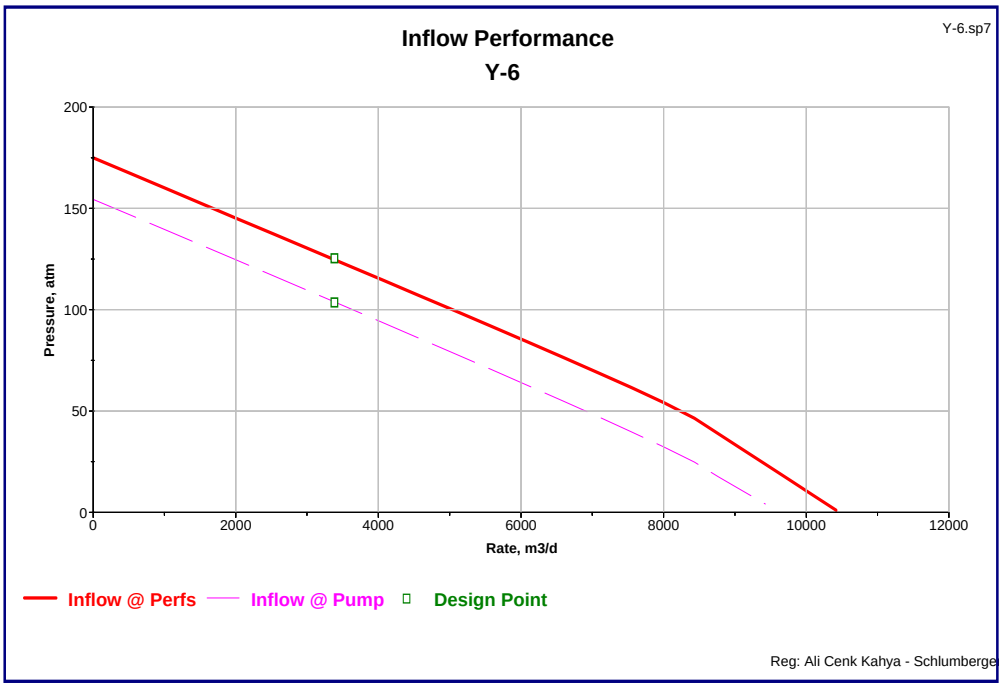

Figure A.6 Inflow performance relation of Y-6 well

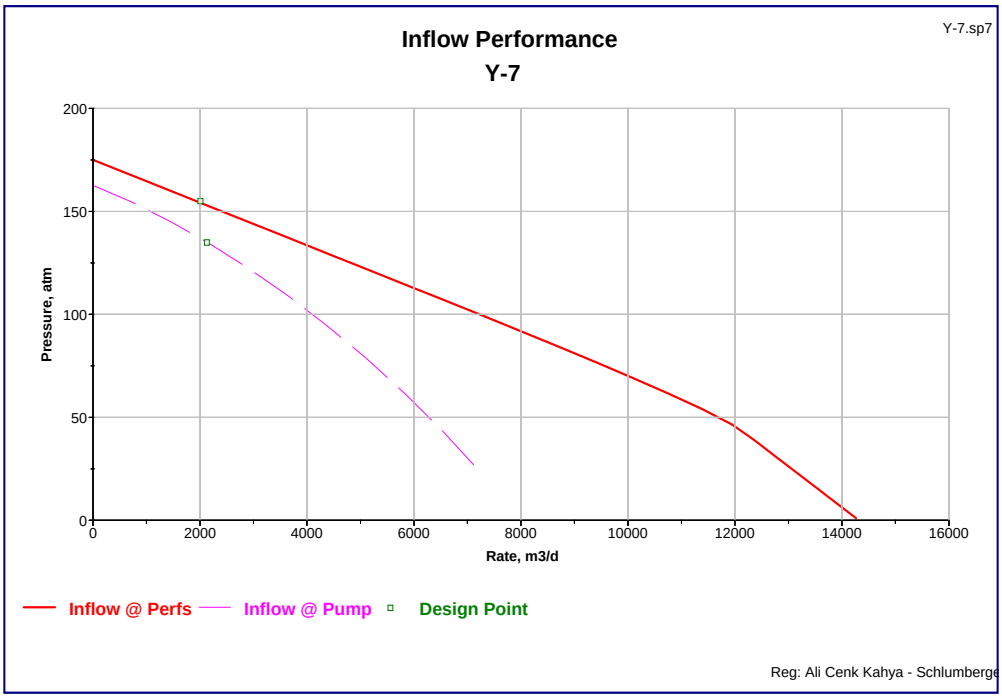

Figure A.7 Inflow performance relation of Y-7 well

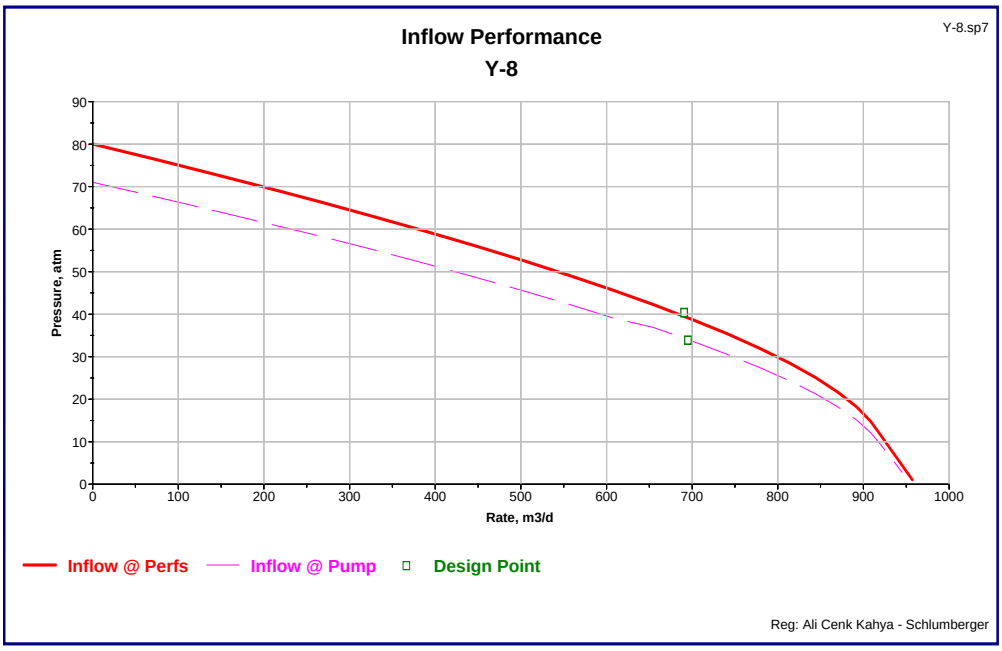

Figure A.8 Inflow performance relation of Y-8 well

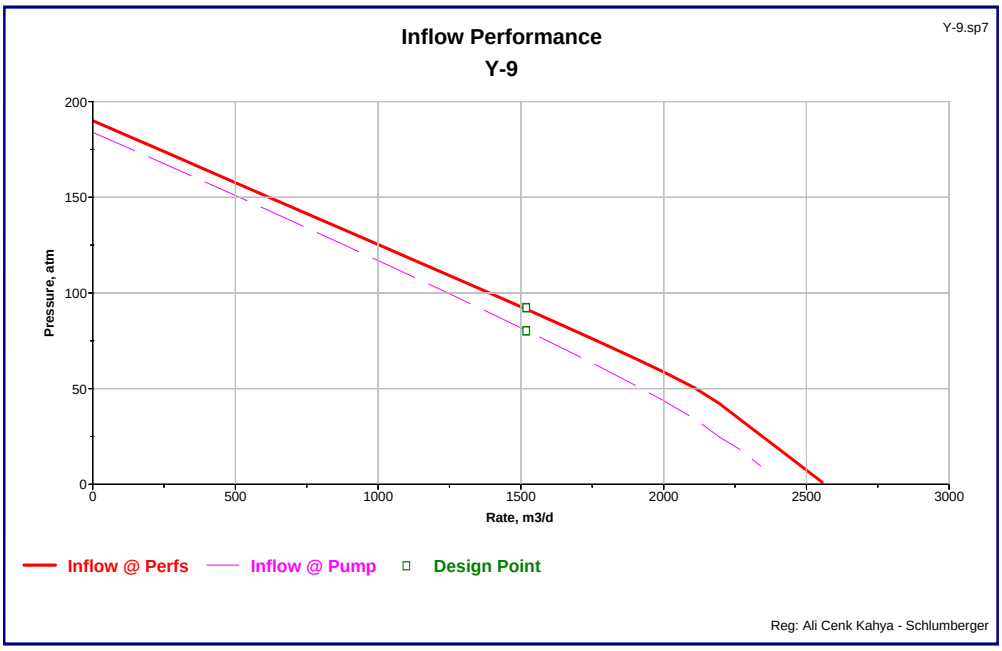

Figure A.9 Inflow performance relation of Y-9 well

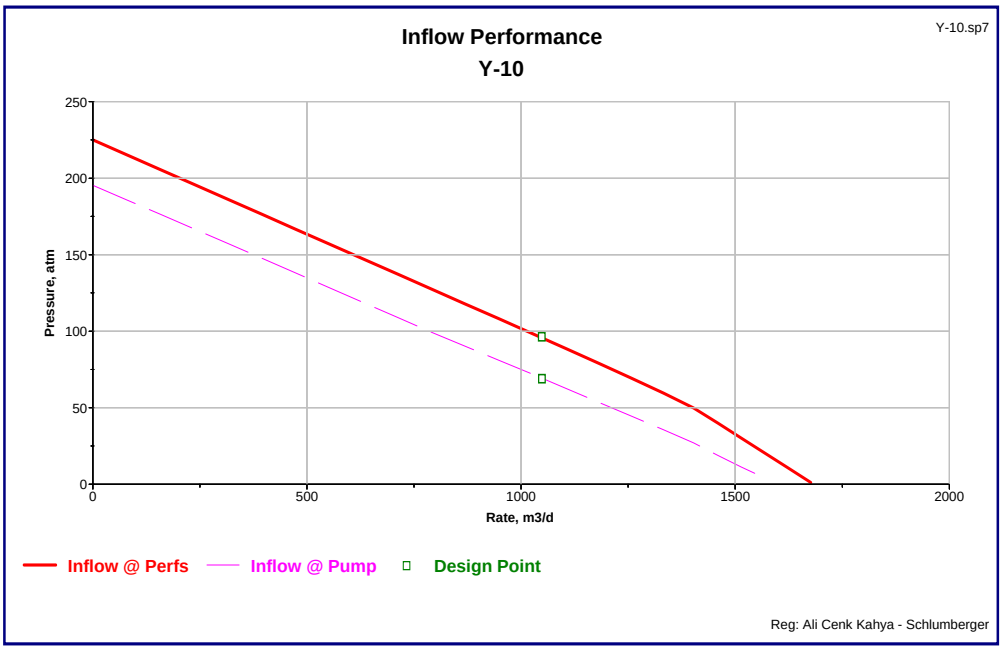

Figure A.10 Inflow performance relation of Y-10 well

APPENDIX B

SUBPUMP SOFTWARE INPUT AND OUTPUT DATA

B.1 SubPUMP Software Input and Output Data for Y-1 Well

Table B.1.1 Tubing and casing data for Y-1 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing: 1	101.60	16.37	88.29	0.016510	2070.0	
Casing: 1	177.80	38.69	159.41	0.016510	3195.0	0.0
Casing: 2	114.30	20.09	99.57	0.016510	3738.0	3155.0

Table B.1.2 Wellbore data for Y-1 well

Pump Depth, m	2070
Top of Perf. (Datum) Depth, m	3195
Bottom Hole Temp, °C	72
Wellhead Temp, °C	20
Outflow Correlation Method	Fancher & Brown (1963)

Table B.1.3 Directional survey data for Y-1 well

No.	MD m	TVD m	Angle Deg
1	500	500	11.3
2	700	696.1	19.3
3	1000	979.3	16.4
4	1340	1305.5	31.8
5	1634	1555.3	29.6
6	1804.1	1703.2	37.5
7	2000.1	1858.6	53.4
8	2039	1881.8	56.7
9	2062.9	1894.9	56.2
10	2079.5	1904.1	56
11	2116.8	1925	56.2
12	2136.2	1935.8	57.8
13	2145.3	1940.6	64.1
14	2203.9	1966.3	76.1
15	2300.8	1989.5	82.4
16	2407.5	2003.6	82
17	2504.4	2017	81.7
18	2601.2	2030.9	81.8
19	2708.3	2046.2	83
20	2746.8	2050.9	84.8
21	3067.2	2080.2	87.3
22	3190	2086.1	88.9
23	3195	2086.2	87.9
24	3298.4	2090	90.3
25	3763.5	2087.7	0

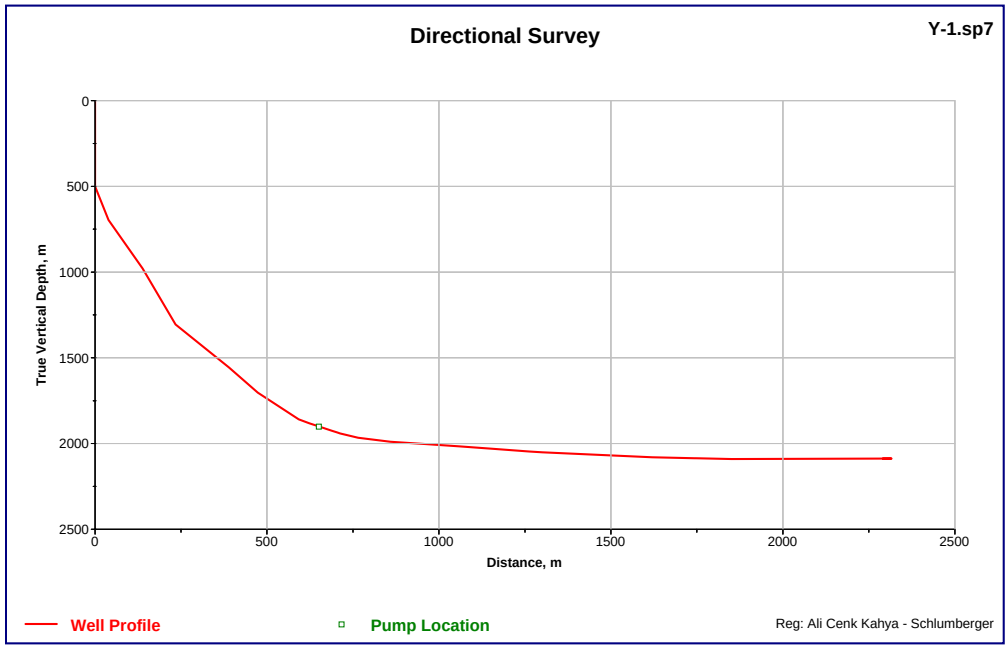

Figure B.1.1 Directional survey profile for Y-1 well

Table B.1.4 Fluid data for Y-1 well

Input Data	
Oil Gravity, g/cc	0.830
SG Gas	0.800
Water Cut, %	85.0
Water Gravity	1.016
Bubble Pt Pressure, atm	110
Prod. Gas/Oil Ratio, m3(g)/m3(l)	104.11
Output Data	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	5.21
Solution GOR, m3(g)/m3(l)	73.26
Average Fluid Viscosity, Pa-s	0.0008544
Fluid Gradient at Pump Intake, psi/ft	0.433

Table B.1.5 Viscosity calibration data for Y-1 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	1.000	20.0	0.009000	Dead	0.0187674	0.480

Table B.1.6 PVT lab data for Y-1 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
72.0	208.000	0.6000

Table B.1.7 Inflow data generated by SubPUMP for Y-1 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	1804.0
Productivity Index, m3/d/Atm	19.60870
Bubble Point Rate, m3/d	1921.7
Max. Oil Flow Rate, m3/d	3120.0
Max. Total Flow Rate, m3/d	3780.5

Table B.1.8 Design criteria for Y-1 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	1804.0
Pump Depth, m	2070.0
Fluid Over Pump, m	1021.1
Pumping Fluid Level, m	1048.9
Pump Intake Pressure, atm	94.228
Total Dynamic Head, m	1209.7
Tubing Pressure, atm	20.000
Casing Pressure, atm	10.000
Bottom Hole Pressure, atm	116.000
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	0.69
Natural Gas Separation, %	16.6
Free Gas into Pump, %	0.25
Gas Separator Installed	Yes
Gas Separator Efficiency,	56.00

Table B.1.9 Well system curve detail for Y-1 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m^3/d	Avg. Pump Rate O+W+G m^3/d	Pumping Fluid Level m
1	6629.45	6362.82	266.63	32.5	33.4	41.8
2	6685.49	5634.31	1051.18	434.7	446.4	264.8
3	6748.7	4908.43	1840.27	836.9	859.4	487.6
4	6850.33	4187.52	2662.8	1239.1	1272.5	714.5
5	7036.24	3457.59	3578.65	1641.4	1685.5	953.3
6	7306.66	2737.87	4568.8	2043.6	2098.5	1188.9
7	7667.15	2021.07	5646.08	2445.8	2511.6	1437.7
8	8182.5	1290.36	6892.13	2848	2924.6	1711.8
PumpOff	9580.34	431.06	9149.28	3250.2	3337.6	2067.2
Design	7132.31	3163.45	3968.85	1804.0	1852.5	1048.9

Table B.1.10 Theoretical pump performance for Y-1 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m^3/d	109.7	109.2	90.3
Gas Rate through Pump, m^3/d	4.7	0.0	N/A
Gas Rate from Casing, m^3/d	8.2	N/A	N/A
Total Gas Rate, m^3/d	N/A	N/A	9401.6
Free Gas Percent, %	0.25	0.00	N/A
Water Rate, Bbl/D	11000.43	10946.12	10791.56
Total Liquid Rate, m3/d	1858.7	1849.5	1806.0
Pressure, atm	94.120	210.948	20.000
Specific Gravity Liquid, wtr=1	0.98	0.99	N/A
Specific Gravity Mixture, wtr=1	0.98	0.99	N/A
Liquid Density, g/cc	0.981	0.985	N/A
Mixture Density, g/cc	0.979	0.985	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m^3 (g)/m^3 (l)	62.15	66.21	N/A
Solution GWR, m^3 (g)/m^3 (l)	1.47	8.57	N/A
Liquid FVF, res/surf	1.03	1.02	N/A
Mixture FVF, res/surf	1.03	1.02	N/A
Gas Deviation Factor	0.820	0.804	N/A

Table B.1.11 Pump data for Y-1 well

Manufacturer	Reda
Series	540
Model	GN10000
Minimum Recommended Rate, m3/d	1107.4**
Maximum Recommended Rate, m3/d	1898.3**
Rate at Peak Efficiency, m3/d	1539.0**
Power at Peak Efficiency, HP	530.0**
Frequency, Hz	60
Number of Stages	174

**Corrected for frequency and viscosity

Table B.1.12 Stage data for Y-1 well generated by SubPUMP

	Design	174 Stages
Total Dynamic Head (TDH), ft	3968.85	3973.04
Surface Rate (O+W), m3/d	1804.0	1806.0
Avg. Pump Rate (O+G+W), m3/d	N/A	1854.6
Pump Intake Pressure, atm	94.228	94.120
Operating Power, HP	N/A	522.1
Pump Efficiency, %	N/A	65.2

Table B.1.13 Motor data for Y-1 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	525
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	2718.35
Name Plate Current, Amps	113.3
Adjust for Motor Slip	No
Design Frequency, Hz	60
Operating Motor Load, HP (@ Design Frequency)	522.1
Operating Motor Load,	82.88
Operating Speed, RPM	3495
Operating Current, Amps	97.1
Operating Voltage, Volts	3262.07
Operating Power Factor, frac	0.808
Harmonic Heating due to VSD, °C	5.4
Operating Efficiency, %	87.9
Total Winding Temp., °C	100
Fluid Velocity, ft/sec	17.346
Well Fluid Temperature, °C	67.3

Table B.1.14 Protector data for Y-1 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BSLSBSL-HL
Bearing Cap., kg	6803.9

Table B.1.15 Cable data for Y-1 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2170
Solve for	Surface Voltage

Table B.1.16 Rate and Efficiency data calculated by SubPUMP for Y-1 well

	Catalog	Actual
Total Stages	174	174
Slip Stages	0	0
Total Dynamic Head (TDH), ft	3973.04	3973.04
Surface Rate (O+W), m3/d	1806.0	1806.0
Avg. Pump Rate (O+G+W), m3/d	1854.6	1854.6
Pump Intake Pressure, atm	94.120	94.120
Operating Power, HP	522.1	517.1
Pump Efficiency, %	65.2	65.2
Operating Speed, RPM	3500	3500

B.2 SubPUMP Software Input and Output Data for Y-2 Well

B.2.1 SubPUMP Software Input and Output Data for Y-2 Well (Current Design)

Table B.2.1.1 Tubing and casing data for Y-2 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing: 1	88.9	19.27	69.85	0.01651	2010	
Casing: 1	177.8	38.69	159.41	0.01651	2629	0
Casing: 2	177.8	20.09	159.41	0.01651	3730	2630

Table B.2.1.2 Wellbore data for Y-2 well

Pump Depth, m	2010
Top of Perf. (Datum) Depth, m	2630
Bottom Hole Temp, °C	72
Wellhead Temp, °C	30
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.2.1.3 Directional survey data for Y-2 well

No.	MD m	TVD m	Angle Deg
1	50	50	12.9
2	300	293.7	13.3
3	600	585.7	22
4	1000	956.6	22.1
5	1301	1235.6	20.4
6	1706.9	1616	19.3
7	2000	1892.6	28.6
8	2303.9	2159.5	48.7
9	2400	2222.8	80.9
10	2601.2	2254.8	89.2
11	2922.4	2259.3	90
12	3380.6	2259.3	89.6
13	3703.1	2261.5	0

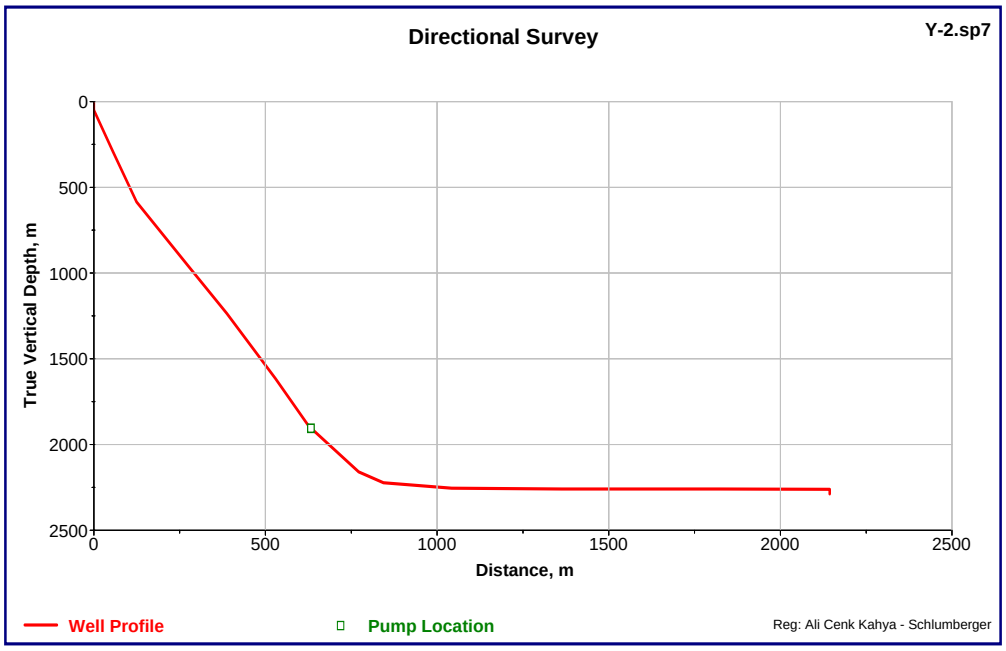

Figure B.2.1 Directional survey profile for Y-2 well

Table B.2.1.4 Fluid data for Y-2 well

Input Data	
Oil Gravity, g/cc	0.829
SG Gas	0.680
Water Cut, %	45.0
Water Gravity	1.016
Bubble Pt Pressure, atm	113.000
Prod. Gas/Oil Ratio, m3(g)/m3(l)	88.23
Output Data	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	48.53
Solution GOR, m3(g)/m3(l)	64.84
Average Fluid Viscosity, Pa-s	0.0017837
Fluid Gradient at Pump Intake, psi/ft	0.224

Table B.2.1.5 Viscosity calibration data for Y-2 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	1.000	20.0	0.0043000	Dead	0.0181801	0.237

Table B.2.1.6 PVT lab data for Y-2 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
72.0	225.000	0.3700

Table B.2.1.7 Inflow data generated by SubPUMP for Y-2 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	680
Productivity Index, m3/d/Atm	0.06199
Bubble Point Rate, m3/d	345.5
Max. Oil Flow Rate, m3/d	739.8
Max. Total Flow Rate, m3/d	767

Table B.2.1.8 Design criteria for Y-2 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	680
Pump Depth, m	2010
Fluid Over Pump, m	231.2
Pumping Fluid Level, m	1778.8
Pump Intake Pressure, atm	30.158
Total Dynamic Head, m	2064.6
Tubing Pressure, atm	11
Casing Pressure, atm	11
Bottom Hole Pressure, atm	47.149
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	58.53
Natural Gas Separation, %	20
Free Gas into Pump, %	25.3
Gas Separator Installed	Yes
Gas Separator Efficiency,	70

Table B.2.1.9 Well system curve detail for Y-2 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	6449.76	5416.59	1033.17	7.4	8.2	373.8
2	4491.15	4840.77	-349.62	98.7	109.3	550.3
3	4731.31	4274.78	456.53	189.9	210.4	734.9
4	5113.81	3690.11	1423.7	281.2	311.6	921.6
5	5534.59	3173.98	2360.6	372.5	412.7	1104.5
6	6055.59	2699.04	3356.56	463.8	513.9	1288.6
7	6655.46	2251.19	4404.27	555.1	615	1462.6
8	7626.23	1673.32	5952.91	646.4	716.1	1683.6
PumpOff	10257.5	690.8	9566.71	737.7	817.3	2007.7
Design	8184.65	1410.88	6773.77	680	753.4	1778.8

Table B.2.1.10 Theoretical pump performance for Y-2 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	406.6	419.1	371.7
Gas Rate through Pump, m3/d	242.7	0	N/A
Gas Rate from Casing, m3/d	768.7	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	32795.8
Free Gas Percent, %	24.54	0	N/A
Water Rate, Bbl/D	1950.29	1939.88	1912.86
Total Liquid Rate, m3/d	716.7	727.5	675.8
Pressure, atm	31.101	175.616	11
Specific Gravity Liquid, wtr=1	0.88	0.86	N/A
Specific Gravity Mixture, wtr=1	0.67	0.86	N/A
Liquid Density, g/cc	0.875	0.861	N/A
Mixture Density, g/cc	0.666	0.861	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	14.44	31.7	N/A
Solution GWR, m3(g)/m3(l)	0.72	6.1	N/A
Liquid FVF, res/surf	1.06	1.08	N/A
Mixture FVF, res/surf	1.41	1.08	N/A
Gas Deviation Factor	0.947	0.837	N/A

Table B.2.1.11 Pump data for Y-2 well

Manufacturer	Reda
Series	540
Model	GN10000
Minimum Recommended Rate, m3/d	1168.6**
Maximum Recommended Rate, m3/d	2003.3**
Rate at Peak Efficiency, m3/d	1539.0**
Power at Peak Efficiency, HP	530.0**
Frequency, Hz	60
Number of Stages	174

**Corrected for frequency and viscosity

Table B.2.1.12 Stage data for Y-2 well generated by SubPUMP

	Design	174 Stages
Total Dynamic Head (TDH), ft	6773.77	6671.02
Surface Rate (O+W), m3/d	680	675.8
Avg. Pump Rate (O+G+W), m3/d	N/A	748.8
Pump Intake Pressure, atm	30.158	31.101
Operating Power, HP	N/A	329.6
Pump Efficiency, %	N/A	62.2

Table B.2.1.13 Motor data for Y-2 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	630
Name Plate Frequency, Hz	60
Name Plate Voltage, Volts	3262.02
Name Plate Current, Amps	113.3
Adjust for Motor Slip	No
Design Frequency, Hz	60
Operating Motor Load, HP (@ Design Frequency)	329.6
Operating Motor Load,	52.33
Operating Speed, RPM	3495
Operating Current, Amps	72.5
Operating Voltage, Volts	3262.07
Operating Power Factor, frac	0.683
Harmonic Heating due to VSD, °C	4.1
Operating Efficiency, %	87.9
Total Winding Temp., °C	91.9
Fluid Velocity, ft/sec	6.491
Well Fluid Temperature, °C	65.4

Table B.2.1.14 Protector data for Y-2 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BPBSL-HL
Bearing Cap., kg	6803.9

Table B.2.1.15 Cable data for Y-2 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2110
Solve for	Surface Voltage

Table B.2.1.16 Rate and Efficiency data calculated by SubPUMP for Y-2 well

	Catalog	Actual
Total Stages	174	174
Slip Stages	0	0
Total Dynamic Head (TDH), ft	6671.02	6671.02
Surface Rate (O+W), m3/d	675.8	675.8
Avg. Pump Rate (O+G+W), m3/d	748.8	748.8
Pump Intake Pressure, atm	31.101	31.101
Operating Power, HP	329.6	324.6
Pump Efficiency, %	62.2	62.2
Operating Speed, RPM	3500	3500

B.2.2 SubPUMP Software Input and Output Data for Y-2 Well (Recommended Design)

Table B.2.2.1 Design criteria for Y-2 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	680
Pump Depth, m	2010
Fluid Over Pump, m	238.4
Pumping Fluid Level, m	1771.6
Pump Intake Pressure, atm	30.705
Total Dynamic Head, m	2091.5
Tubing Pressure, atm	11
Casing Pressure, atm	11
Bottom Hole Pressure, atm	47.149
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	57.96
Natural Gas Separation, %	32.1
Free Gas into Pump, %	21.92
Gas Separator Installed	Yes
Gas Separator Efficiency,	70

Table B.2.2.2 Well system curve detail for Y-2 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	6511.61	5415.09	1096.52	7.4	8.1	373.9
2	4587.65	4842.49	-254.84	98.9	108.7	550.8
3	4824.91	4271.68	553.23	190.4	209.3	735.6
4	5213.95	3687.17	1526.78	281.9	309.9	922.1
5	5642.72	3171.57	2471.15	373.4	410.5	1104.7
6	6170.98	2698.63	3472.36	464.9	511.1	1287.9
7	6777.07	2252.32	4524.75	556.3	611.7	1461.2
8	7759.69	1676.52	6083.17	647.8	712.3	1681.5
PumpOff	10436.2	689.18	9747.06	739.3	812.9	2007.7
Design	8290.81	1428.88	6861.93	680	747.7	1771.6

Table B.2.2.3 Theoretical pump performance for Y-2 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	409.6	419.5	374.1
Gas Rate through Pump, m3/d	202.6	0	N/A
Gas Rate from Casing, m3/d	792.2	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	33011.1
Free Gas Percent, %	21.96	0	N/A
Water Rate, Bbl/D	1963.08	1952.21	1925.41
Total Liquid Rate, m3/d	721.7	729.9	680.3
Pressure, atm	30.647	173.021	11
Specific Gravity Liquid, wtr=1	0.88	0.86	N/A
Specific Gravity Mixture, wtr=1	0.69	0.86	N/A
Liquid Density, g/cc	0.875	0.863	N/A
Mixture Density, g/cc	0.688	0.863	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	14.19	28.89	N/A
Solution GWR, m3(g)/m3(l)	0.71	5.79	N/A
Liquid FVF, res/surf	1.06	1.07	N/A
Mixture FVF, res/surf	1.36	1.07	N/A
Gas Deviation Factor	0.948	0.836	N/A

Table B.2.2.4 Pump data for Y-2 well

Manufacturer	Reda
Series	540
Model	GN5200
Minimum Recommended Rate, m3/d	586.0**
Maximum Recommended Rate, m3/d	991.6**
Rate at Peak Efficiency, m3/d	788.6**
Power at Peak Efficiency, HP	329.7**
Frequency, Hz	54
Number of Stages	260

**Corrected for frequency and viscosity

Table B.2.2.5 Stage data for Y-2 well generated by SubPUMP

	Design	260 Stages
Total Dynamic Head (TDH), ft	6861.93	6873.56
Surface Rate (O+W), m3/d	680	680.3
Avg. Pump Rate (O+G+W), m3/d	N/A	747.9
Pump Intake Pressure, atm	30.705	30.647
Operating Power, HP	N/A	250.2
Pump Efficiency, %	N/A	77.9

Table B.2.2.6 Motor data for Y-2 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	378
Name Plate Frequency, Hz	60
Name Plate Voltage, Volts	3300.97
Name Plate Current, Amps	66.8
Adjust for Motor Slip	No
Design Frequency, Hz	54
Operating Motor Load, HP (@ Design Frequency)	250.2
Operating Motor Load,	73.55
Operating Speed, RPM	3146
Operating Current, Amps	52.9
Operating Voltage, Volts	2970.93
Operating Power Factor, frac	0.781
Harmonic Heating due to VSD, °C	4.9
Operating Efficiency, %	87.9
Total Winding Temp., °C	97.3
Fluid Velocity, ft/sec	6.533
Well Fluid Temperature, °C	65.4

.

Table B.2.2.7 Protector data for Y-2 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BPBSL-HL
Bearing Cap., kg	6803.9

Table B.2.2.8 Cable data for Y-2 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2110
Solve for	Surface Voltage

Table B.2.2.9Rate and Efficiency data calculated by SubPUMP for Y-2 well

	Catalog	Actual
Total Stages	260	260
Slip Stages	0	0
Total Dynamic Head (TDH), ft	6873.56	6873.56
Surface Rate (O+W), m3/d	680.3	680.3
Avg. Pump Rate (O+G+W), m3/d	747.9	747.9
Pump Intake Pressure, atm	30.647	30.647
Operating Power, HP	250.2	246.6
Pump Efficiency, %	77.9	77.9
Operating Speed, RPM	3150	3150

B.3 SubPUMP Software Input and Output Data for Y-3 Well

Table B.3.1 Tubing and casing data for Y-3 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	88.90	13.84	76.00	0.016510	2194.0	
Casing 1	177.80	38.69	159.41	0.016510	2565.0	0.0
Casing 2	114.30	17.26	101.60	0.016510	3671.0	2525.0

Table B.3.2 Wellbore data for Y-3 well

Pump Depth, m	2194.0
Top of Perf. (Datum) Depth, m	2561.0
Bottom Hole Temp, °C	74.0
Wellhead Temp, °C	20
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.3.3 Directional survey data for Y-3 well

No.	MD m	TVD m	Angle Deg
1	500	500	14.7
2	700	693.4	16.3
3	1000	981.4	14.9
4	1140	1116.7	14.6
5	1460	1426.4	17.1
6	1600	1560.2	14.8
7	1800	1753.5	13.1
8	2007.8	1955.9	21.8
9	2111	2051.7	30.9
10	2186.8	2116.8	31.2
11	2226	2150.3	30.7
12	2240.8	2163	35.4
13	2307.6	2217.5	67.2
14	2561	2315.6	88.4
15	2866.7	2324	90.2
16	3671.5	2321.4	0

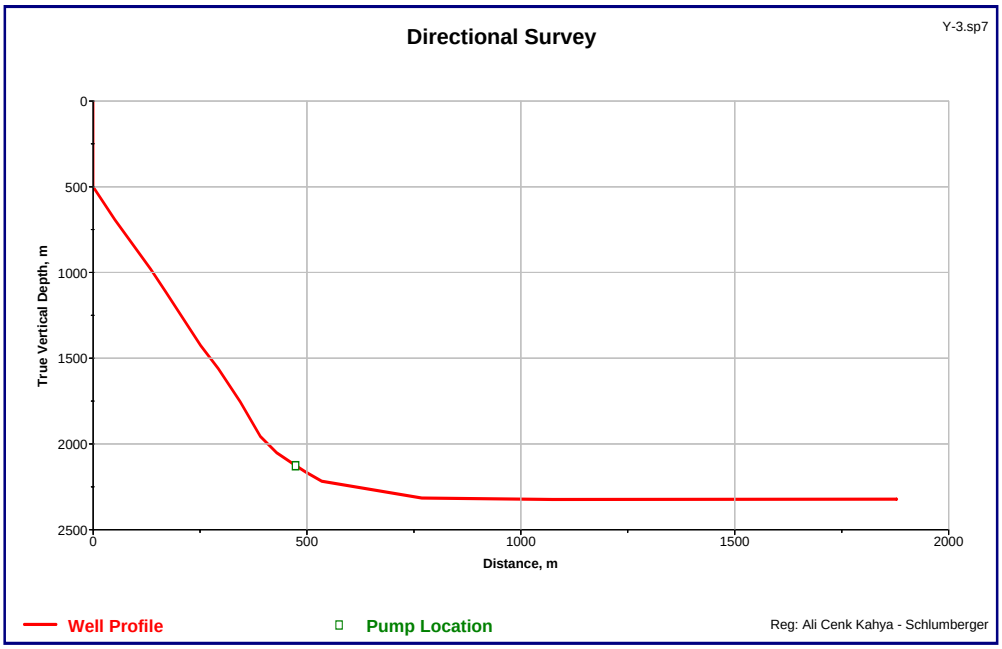

Figure B.3.1 Directional survey profile for Y-3 well

Table B.3.4 Fluid data for Y-3 well

Input Data	
Oil Gravity, g/cc	0.820
SG Gas	0.800
Water Cut, %	56.0
Water Gravity	1.016
Bubble Pt Pressure, atm	146.288
Prod. Gas/Oil Ratio, m3(g)/m3(l)	110.62
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	48.67
Solution GOR, m3(g)/m3(l)	108.11
Average Fluid Viscosity, Pa-s	0.0021016
Fluid Gradient at Pump Intake, psi/ft	0.228

Table B.3.5 Viscosity calibration data for Y-3 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	1.000	20.0	0.0043000	Dead	0.0140082	0.307

Table B.3.6 PVT lab data for Y-3 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
74.0	231.000	0.3700

Table B.3.7 Inflow data generated by SubPUMP for Y-3 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	998.0
Productivity Index, m3/d/Atm	6.19949
Bubble Point Rate, m3/d	525.2
Max. Oil Flow Rate, m3/d	1029.0
Max. Total Flow Rate, m3/d	1080.7

Table B.3.8 Design criteria for Y-3 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	998.0
Pump Depth, m	2194.0
Fluid Over Pump, m	322.8
Pumping Fluid Level, m	1871.2
Pump Intake Pressure, atm	38.611
Total Dynamic Head, m	2251.6
Tubing Pressure, atm	10.000
Casing Pressure, atm	12.000
Bottom Hole Pressure, atm	50.703
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	48.58
Natural Gas Separation, %	18.5
Free Gas into Pump, %	26.58
Gas Separator Installed	Yes
Gas Separator Efficiency,	53.00

Table B.3.9 Well system curve detail for Y-3 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	7105.3	8357.25	-1252	10.5	11.9	-292.2
2	4915.61	7515.32	-2599.7	140.2	158.8	-43.4
3	5172.65	6673.95	-1501.3	269.8	305.7	207.6
4	5431.43	5852.32	-420.9	399.5	452.6	460.6
5	5798.1	5005.41	792.69	529.2	599.4	722.3
6	6304.09	4202.66	2101.43	658.9	746.3	995.3
7	6980.8	3399.01	3581.8	788.6	893.2	1282.8
8	7989.45	2526.45	5463	918.2	1040.1	1611
PumpOff	11837.8	818.61	11019.2	1047.9	1187	2191
Design	9195.22	1808.25	7386.97	998	1130.5	1871.2

Table B.3.10 Theoretical pump performance for Y-3 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	496.5	524.3	439.2
Gas Rate through Pump, m3/d	386.4	0	N/A
Gas Rate from Casing, m3/d	622.4	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	48587.5
Free Gas Percent, %	26.65	0	N/A
Water Rate, Bbl/D	3592.79	3572.22	3516.24
Total Liquid Rate, m3/d	1067.7	1092.2	998.3
Pressure, atm	38.509	191.739	10
Specific Gravity Liquid, wtr=1	0.89	0.87	N/A
Specific Gravity Mixture, wtr=1	0.66	0.87	N/A
Liquid Density, g/cc	0.884	0.867	N/A
Mixture Density, g/cc	0.658	0.867	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	28.29	58.82	N/A
Solution GWR, m3(g)/m3(l)	0.8	7.21	N/A
Liquid FVF, res/surf	1.07	1.09	N/A
Mixture FVF, res/surf	1.46	1.09	N/A
Gas Deviation Factor	0.92	0.819	N/A

Table B.3.11 Pump data for Y-3 well

Manufacturer	Reda
Series	540
Model	GN10000
Minimum Recommended Rate, m3/d	1065.1**
Maximum Recommended Rate, m3/d	1825.8**
Rate at Peak Efficiency, m3/d	1487.7**
Power at Peak Efficiency, HP	638.4**
Frequency, Hz	58
Number of Stages	232

**Corrected for frequency and viscosity

Table B.3.12 Stage data for Y-3 well generated by SubPUMP

	Design	232 Stages
Total Dynamic Head (TDH), ft	7386.97	7406.61
Surface Rate (O+W), m3/d	998.0	998.3
Avg. Pump Rate (O+G+W), m3/d	N/A	1130.8
Pump Intake Pressure, atm	38.611	38.509
Operating Power, HP	N/A	460.3
Pump Efficiency, %	N/A	70.2

Table B.3.13 Motor data for Y-3 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	600
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	2889.35
Name Plate Current, Amps	123.8
Adjust for Motor Slip	No
Design Frequency, Hz	58
Operating Motor Load, HP (@ Design Frequency)	460.3
Operating Motor Load,	66.13
Operating Speed, RPM	3376
Operating Current, Amps	91
Operating Voltage, Volts	3351.71
Operating Power Factor, frac	0.739
Harmonic Heating due to VSD, °C	5
Operating Efficiency, %	87.9
Total Winding Temp., °C	101.3
Fluid Velocity, ft/sec	9.588
Well Fluid Temperature, °C	69.5

Table B.3.14 Protector data for Y-3 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BSLSBSL-HL
Bearing Cap., kg	6577.2

Table B.3.15 Cable data for Y-3 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2294
Solve for	Surface Voltage

Table B.3.16 Rate and Efficiency data calculated by SubPUMP for Y-3 well

	Catalog	Actual
Total Stages	232	232
Slip Stages	0	0
Total Dynamic Head (TDH), ft	7406.61	7406.61
Surface Rate (O+W), m3/d	998.3	998.3
Avg. Pump Rate (O+G+W), m3/d	1130.8	1130.8
Pump Intake Pressure, atm	38.509	38.509
Operating Power, HP	460.3	455.8
Pump Efficiency, %	70.2	70.2
Operating Speed, RPM	3383	3383

B.4 SubPUMP Software Input and Output Data for Y-4 Well

Table B.4.1 Tubing and casing data for Y-4 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	114.30	18.97	100.53	0.016510	2500.0	
Casing 1	219.08	53.57	198.76	0.016510	2572.0	0.0
Casing 2	127.00	26.79	108.61	0.016510	3287.0	2572.0

Table B.4.2 Wellbore data for Y-4 well

Pump Depth, m	2500.0
Top of Perf. (Datum) Depth, m	2572.0
Bottom Hole Temp, °C	68.0
Wellhead Temp, °C	30.0
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.4.3 Directional survey data for Y-4 well

No.	MD m	TVD m	Angle Deg
1	100	100	4.2
2	504.8	503.7	13.6
3	1003.9	988.8	23.7
4	1510.2	1452.3	25.2
5	2009.3	1904.1	49.2
6	2505.7	2228.3	88.1
7	2998.9	2244.8	89.9
8	3287	2245.4	0

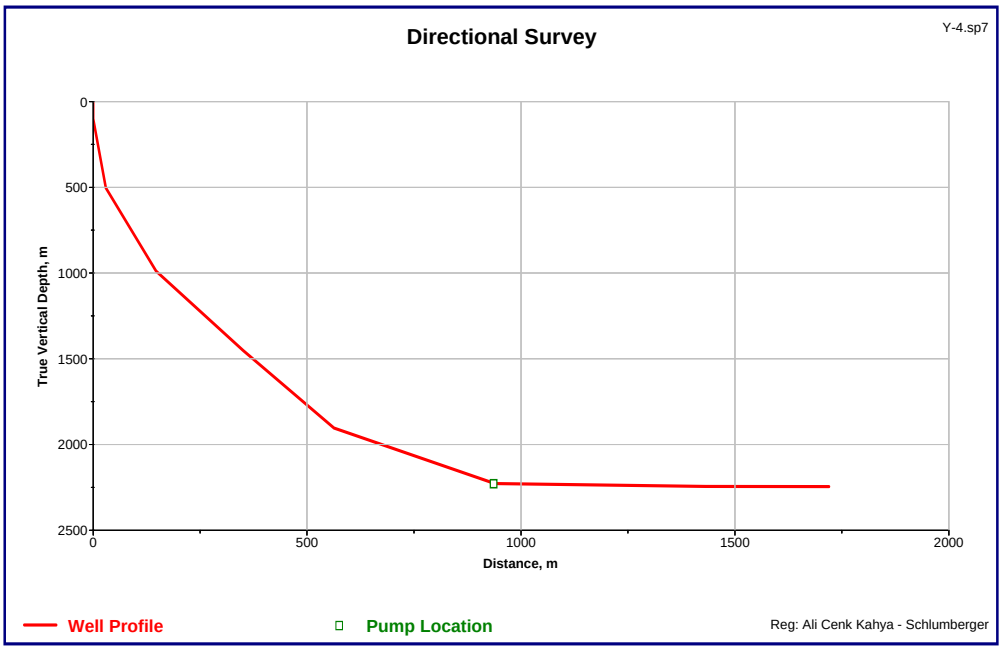

Figure B.4.1 Directional survey profile for Y-4 well

Table B.4.4 Fluid data for Y-4 well

Input Data	
Oil Gravity, g/cc	0.841
SG Gas	0.700
Water Cut, %	15.0
Water Gravity	1.004
Bubble Pt Pressure, atm	94.00
Prod. Gas/Oil Ratio, m3(g)/m3(l)	54.96
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	46.71
Solution GOR, m3(g)/m3(l)	54.68
Average Fluid Viscosity, Pa-s	0.0017728
Fluid Gradient at Pump Intake, psi/ft	0.278

Table B.4.5 Viscosity calibration data for Y-4 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table B.4.6 PVT lab data for Y-4 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
68	94	0.00136
68	222	0.0017

Table B.4.7 Inflow data generated by SubPUMP for Y-4 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	555
Productivity Index, m3/d/Atm	0.03335
Bubble Point Rate, m3/d	432.6
Max. Oil Flow Rate, m3/d	609.1
Max. Total Flow Rate, m3/d	612

Table B.4.8 Design criteria for Y-4 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	555
Pump Depth, m	2500
Fluid Over Pump, m	677.7
Pumping Fluid Level, m	1822.3
Pump Intake Pressure, atm	48.78
Total Dynamic Head, m	1539
Tubing Pressure, atm	10
Casing Pressure, atm	10
Bottom Hole Pressure, atm	49.123
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	32.72
Natural Gas Separation, %	21
Free Gas into Pump, %	14.74
Gas Separator Installed	Yes
Gas Separator Efficiency,	55

Table B.4.9 Well system curve detail for Y-4 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	7560.07	9189.81	-1630	6.1	6.5	-481.6
2	5758.18	8249.21	-2491	81	87.2	-195.3
3	5409.52	7314.7	-1905	155.9	167.9	91.9
4	5401.71	6382.05	-980.3	230.9	248.6	376.5
5	5479.08	5449.74	29.34	305.8	329.3	666.8
6	5545.83	4517.25	1028.6	380.8	410	962.2
7	5756.22	3562.22	2194	455.7	490.7	1278.1
8	6674.12	2586.09	4088	530.6	571.4	1663.5
PumpOff	11394.14	716.27	10678	605.6	652.1	2496.4
Design	7258.17	2208.9	5049.3	555	597.7	1822.3

Table B.4.10 Theoretical pump performance for Y-4 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	495.1	505.4	470.1
Gas Rate through Pump, m3/d	100.2	0	N/A
Gas Rate from Casing, m3/d	181.7	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	25833.2
Free Gas Percent, %	14.21	0	N/A
Water Rate, Bbl/D	532.28	529.85	521.75
Total Liquid Rate, m3/d	579.7	589.7	553
Pressure, atm	49.687	160.978	10
Specific Gravity Liquid, wtr=1	0.81	0.8	N/A
Specific Gravity Mixture, wtr=1	0.7	0.8	N/A
Liquid Density, g/cc	0.81	0.795	N/A
Mixture Density, g/cc	0.7	0.795	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	28.38	37.85	N/A
Solution GWR, m3(g)/m3(l)	1.03	6.98	N/A
Liquid FVF, res/surf	1.05	1.07	N/A
Mixture FVF, res/surf	1.22	1.07	N/A
Gas Deviation Factor	0.916	0.825	N/A

Table B.4.11 Pump data for Y-4 well

Manufacturer	Reda
Series	540
Model	GN5200
Minimum Recommended Rate, m3/d	535.5**
Maximum Recommended Rate, m3/d	906.3**
Rate at Peak Efficiency, m3/d	730.2**
Power at Peak Efficiency, HP	205.4**
Frequency, Hz	50
Number of Stages	204

**Corrected for frequency and viscosity

Table B.4.12 Stage data for Y-4 well generated by SubPUMP

	Design	204 Stages
Total Dynamic Head (TDH), ft	5049.27	5079.35
Surface Rate (O+W), m3/d	555	555.3
Avg. Pump Rate (O+G+W), m3/d	N/A	598
Pump Intake Pressure, atm	48.78	48.647
Operating Power, HP	N/A	152.6
Pump Efficiency, %	N/A	73.2

Table B.4.13 Motor data for Y-4 well generated by SubPUMP

Manufacturer	Reda
Series	456
Name Plate Power, HP	300
Name Plate Frequency, Hz	60
Name Plate Voltage, Volts	2630
Name Plate Current, Amps	71
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP (@ Design Frequency)	152.6
Operating Motor Load,	61.04
Operating Speed, RPM	2890
Operating Current, Amps	45.8
Operating Voltage, Volts	2191.71
Operating Power Factor, frac	0.768
Harmonic Heating due to VSD, °C	4.3
Operating Efficiency, %	77.89
Total Winding Temp., °C	110
Fluid Velocity, ft/sec	1.025
Well Fluid Temperature, °C	67.9

Table B.4.14 Protector data for Y-4 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	LSBPB-HL
Bearing Cap., kg	5670

Table B.4.15 Cable data for Y-4 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2170
Solve for	Surface Voltage

Table B.4.16 Rate and Efficiency data calculated by SubPUMP for Y-4 well

	Catalog	Actual
Total Stages	204	204
Slip Stages	0	0
Total Dynamic Head (TDH), ft	5079.35	4971.75
Surface Rate (O+W), m3/d	555.3	553
Avg. Pump Rate (O+G+W), m3/d	598	595.5
Pump Intake Pressure, atm	48.647	49.687
Operating Power, HP	152.6	149.7
Pump Efficiency, %	73.2	72.6
Operating Speed, RPM	2916	2889

B.5 SubPUMP Software Input and Output Data for Y-5 Well

B.5.1 SubPUMP Software Input and Output Data for Y-5 Well (Current Design)

Table B.5.1.1 Tubing and casing data for Y-5 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	88.90	13.84	76.00	0.016510	2290.0	0.0
Casing 1	177.80	38.69	159.41	0.016510	2660.0	0.0
Casing 2	114.30	20.09	99.57	0.016510	3482.0	2620.0

Table B.5.1.2 Wellbore data for Y-5 well

Pump Depth, m	2290
Top of Perf. (Datum) Depth, m	2665.2
Bottom Hole Temp, °C	72
Wellhead Temp, °C	20
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.5.1.3 Directional survey data for Y-5 well

No.	MD m	TVD m	Angle Deg
1	500	500	18.9
2	800	783.9	27.1
3	1000	962	30.9
4	1240	1167.9	30.8
5	1400	1305.4	32.2
6	1640	1508.5	20.2
7	2001.3	1847.6	12.5
8	2074.1	1918.7	23.2
9	2209.8	2043.4	38.9
10	2277.9	2096.4	44.8
11	2289.4	2104.6	45
12	2309.1	2118.5	45.2
13	2326.4	2130.7	45.3
14	2344.3	2143.3	45.1
15	2354.5	2150.5	45.1
16	2381.2	2169.3	50.7
17	2440	2206.6	73.8
18	2665.2	2269.5	88.8
19	2765.7	2271.6	89.9
20	3482.1	2272.7	0

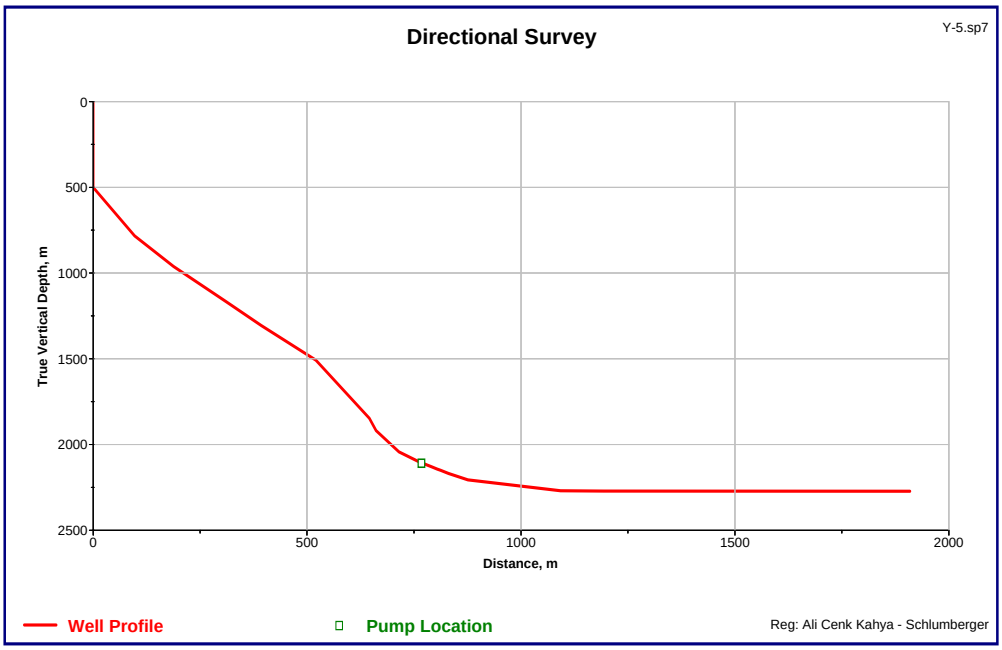

Figure B.5.1 Directional survey profile for Y-5 well

Table B.5.1.4 Fluid data for Y-5 well

Input Data	
Oil Gravity, g/cc	0.820
SG Gas	0.920
Water Cut, %	25.0
Water Gravity	1.016
Bubble Pt Pressure, atm	146.000
Prod. Gas/Oil Ratio, m3(g)/m3(l)	150.00
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	112.50
Solution GOR, m3(g)/m3(l)	127.74
Average Fluid Viscosity, Pa-s	0.0037110
Fluid Gradient at Pump Intake, psi/ft	0.332

Table B.5.1.5 Viscosity calibration data for Y-5 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	1	20	0.0043	Dead	0.01401	0.307

Table B.5.1.6 PVT lab data for Y-5 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
72.0	225.000	0.3700

Table B.5.1.7 Inflow data generated by SubPUMP for Y-5 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	853
Productivity Index, m3/d/Atm	11.3733
Bubble Point Rate, m3/d	898.5
Max. Oil Flow Rate, m3/d	1821
Max. Total Flow Rate, m3/d	1848.3

Table B.5.1.8 Design criteria for Y-5 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	1100
Pump Depth, m	2290
Fluid Over Pump, m	1593
Pumping Fluid Level, m	697
Pump Intake Pressure, atm	114.04
Total Dynamic Head, m	768.4
Tubing Pressure, atm	12
Casing Pressure, atm	9
Bottom Hole Pressure, atm	127.473
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	19.78
Natural Gas Separation, %	22
Free Gas into Pump, %	4.06
Gas Separator Installed	Yes
Gas Separator Efficiency,	78

Table B.5.1.9 Well system curve detail for Y-5 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	4893.46	9473.61	-4580.1	17.9	22.3	-604.9
2	4344.25	8835.19	-4490.9	239.1	297.7	-350.1
3	4945.76	7670.78	-2725	460.4	573.2	-89.4
4	5620.17	6654.87	-1034.7	681.6	848.7	176.1
5	6610.19	5761.36	848.83	902.8	1124.2	445.1
6	7621.69	4884.37	2737.32	1124.1	1399.7	731
7	8850.25	4017.23	4833.02	1345.3	1675.2	1081.4
8	10723.4	3044.59	7678.84	1566.6	1950.6	1520.8
PumpOff	16783.4	748.24	16035.2	1787.8	2226.1	2286.5
Design	7498.4	4977.35	2521.04	1100	1369.7	697

Table B.5.1.10 Theoretical pump performance for Y-5 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	1087.1	1095.7	833.8
Gas Rate through Pump, m3/d	58	0	N/A
Gas Rate from Casing, m3/d	280	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	125068
Free Gas Percent, %	4.2	0	N/A
Water Rate, Bbl/D	1782.15	1778	1748.11
Total Liquid Rate, m3/d	1370.5	1378.3	1111.7
Pressure, atm	112.88	169.548	12
Specific Gravity Liquid, wtr=1	0.77	0.76	N/A
Specific Gravity Mixture, wtr=1	0.75	0.76	N/A
Liquid Density, g/cc	0.771	0.76	N/A
Mixture Density, g/cc	0.745	0.76	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	95.78	104.96	N/A
Solution GWR, m3(g)/m3(l)	1.67	9.86	N/A
Liquid FVF, res/surf	1.23	1.23	N/A
Mixture FVF, res/surf	1.28	1.23	N/A
Gas Deviation Factor	0.746	0.751	N/A

Table B.5.1.11 Pump data for Y-5 well

Manufacturer	Reda
Series	538
Model	SN8500
Minimum Recommended Rate, m3/d	716.7**
Maximum Recommended Rate, m3/d	1314.0**
Rate at Peak Efficiency, m3/d	1103.7**
Power at Peak Efficiency, HP	377.2**
Frequency, Hz	49
Number of Stages	219

**Corrected for frequency and viscosity

Table B.5.1.12 Stage data for Y-5 well generated by SubPUMP

	Design	219 Stages
Total Dynamic Head (TDH), ft	2521.04	2625.34
Surface Rate (O+W), m3/d	1100	1111.7
Avg. Pump Rate (O+G+W), m3/d	N/A	1384.3
Pump Intake Pressure, atm	114.04	112.88
Operating Power, HP	N/A	337
Pump Efficiency, %	N/A	47

Table B.5.1.13 Motor data for Y-5 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	600
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	2889.35
Name Plate Current, Amps	123.8
Adjust for Motor Slip	No
Design Frequency, Hz	49
Operating Motor Load, HP (@ Design Frequency)	337
Operating Motor Load,	57.31
Operating Speed, RPM	2852
Operating Current, Amps	83.5
Operating Voltage, Volts	2831.62
Operating Power Factor, frac	0.698
Harmonic Heating due to VSD, °C	4.6
Operating Efficiency, %	87.9
Total Winding Temp., °C	96.9
Fluid Velocity, ft/sec	10.677
Well Fluid Temperature, °C	68.2

Table B.5.1.14 Protector data for Y-5 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	LSBPBSL-HL
Bearing Cap., kg	5556.6

Table B.5.1.15 Cable data for Y-5 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2390
Solve for	Surface Voltage

Table B.5.1.16 Rate and Efficiency data calculated by SubPUMP for Y-5 well

	Catalog	Actual
Total Stages	219	219
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2625.34	2625.34
Surface Rate (O+W), m3/d	6992.46	6992.46
Avg. Pump Rate (O+G+W), m3/d	8706.79	8706.79
Pump Intake Pressure, atm	112.88	112.88
Operating Power, HP	337	334.3
Pump Efficiency, %	47	47
Operating Speed, RPM	2858	2858

B.5.2 SubPUMP Software Input and Output Data for Y-5 Well (Recommended Design)

Table B.5.2.1 Design criteria for Y-5 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	1100
Pump Depth, m	2290
Fluid Over Pump, m	1614
Pumping Fluid Level, m	676
Pump Intake Pressure, atm	115.506
Total Dynamic Head, m	763.4
Tubing Pressure, atm	12
Casing Pressure, atm	9
Bottom Hole Pressure, atm	127.473
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	19.07
Natural Gas Separation, %	22
Free Gas into Pump, %	3.89
Gas Separator Installed	Yes
Gas Separator Efficiency,	78

Table B.5.2.2 Well system curve detail for Y-5 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	4931.08	9458.76	-4527.7	18.1	22.6	-604.7
2	4388.68	8801.93	-4413.3	242.2	302.7	-347.9
3	5004.42	7645.42	-2641	466.2	582.7	-86.9
4	5713.13	6655.43	-942.31	690.3	862.8	177.5
5	6711.13	5768.58	942.54	914.4	1142.8	443.4
6	7730.57	4890.29	2840.27	1138.4	1422.8	729.1
7	8976.23	4026.13	4950.1	1362.5	1702.9	1077.6
8	10881	3040.19	7840.77	1586.6	1982.9	1522.8
PumpOff	17010.3	748.24	16262.1	1810.7	2263	2286.5
Design	7540.03	5035.37	2504.65	1100	1374.8	676

Table B.5.2.3 Theoretical pump performance for Y-5 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	1080.8	1088.6	826.4
Gas Rate through Pump, m3/d	55	0	N/A
Gas Rate from Casing, m3/d	265.7	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	123965
Free Gas Percent, %	3.91	0	N/A
Water Rate, Bbl/D	1766.39	1762.28	1732.7
Total Liquid Rate, m3/d	1361.6	1368.8	1101.9
Pressure, atm	115.322	172.187	12
Specific Gravity Liquid, wtr=1	0.77	0.76	N/A
Specific Gravity Mixture, wtr=1	0.75	0.76	N/A
Liquid Density, g/cc	0.77	0.76	N/A
Mixture Density, g/cc	0.746	0.76	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	98.24	107	N/A
Solution GWR, m3(g)/m3(l)	1.69	9.97	N/A
Liquid FVF, res/surf	1.24	1.24	N/A
Mixture FVF, res/surf	1.29	1.24	N/A
Gas Deviation Factor	0.743	0.738	N/A

Table B.5.2.4 Pump data for Y-5 well

Manufacturer	Reda
Series	540
Model	GN10000
Minimum Recommended Rate, m3/d	889.3**
Maximum Recommended Rate, m3/d	1524.5**
Rate at Peak Efficiency, m3/d	1333.8**
Power at Peak Efficiency, HP	273.6**
Frequency, Hz	52
Number of Stages	138

**Corrected for frequency and viscosity

Table B.5.2.5 Stage data for Y-5 well generated by SubPUMP

	Design	138 Stages
Total Dynamic Head (TDH), ft	2504.65	2507.12
Surface Rate (O+W), m3/d	1100	1100.4
Avg. Pump Rate (O+G+W), m3/d	N/A	1375.3
Pump Intake Pressure, atm	115.506	115.469
Operating Power, HP	N/A	245.3
Pump Efficiency, %	N/A	51.5

Table B.5.2.6 Motor data for Y-5 well generated by SubPUMP

Manufacturer	Reda
Series	540D2
Name Plate Power, HP	350
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	2770
Name Plate Current, Amps	79.5
Adjust for Motor Slip	Yes
Design Frequency, Hz	52
Operating Motor Load, HP (@ Design Frequency)	245.3
Operating Motor Load,	67.39
Operating Speed, RPM	3040
Operating Current, Amps	53
Operating Voltage, Volts	2880.8
Operating Power Factor, frac	0.795
Harmonic Heating due to VSD, °C	3.9
Operating Efficiency, %	85.08
Total Winding Temp., °C	93.4
Fluid Velocity, ft/sec	8.075
Well Fluid Temperature, °C	68.2

.

Table B.5.2.7 Protector data for Y-5 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	LSBPBSL-HL
Bearing Cap., kg	5896.7

Table B.5.2.8 Cable data for Y-5 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2390
Solve for	Surface Voltage

Table B.5.2.9 Rate and Efficiency data calculated by SubPUMP for Y-5 well

	Catalog	Actual
Total Stages	138	138
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2507.12	2523.26
Surface Rate (O+W), m3/d	6921.2	6930.8
Avg. Pump Rate (O+G+W), m3/d	8650.21	8662.2
Pump Intake Pressure, atm	115.469	115.322
Operating Power, HP	245.3	242.1
Pump Efficiency, %	51.5	50.7
Operating Speed, RPM	3033	3039

B.6 SubPUMP Software Input and Output Data for Y-6 Well

Table B.6.1 Tubing and casing data for Y-6 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	114.30	17.26	101.60	0.016510	1650.0	0.0
Casing 1	219.08	53.57	198.76	0.016510	2160.0	0.0

Table B.6.2 Wellbore data for Y-6 well

Pump Depth, m	1650
Top of Perf. (Datum) Depth, m	2102
Bottom Hole Temp, °C	51
Wellhead Temp, °C	30
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.6.3 Directional survey data for Y-6 well

No.	MD m	TVD m	Angle Deg
1	300	300	12.1
2	600.5	593.9	20.6
3	990.6	959.1	20.2
4	1415.3	1357.6	30.1
5	1717.2	1618.8	47.6
6	1904.3	1744.8	81.2
7	2111.1	1776.4	90
8	2508.6	1776.5	89.7
9	2707.6	1777.7	90.2
10	2866.4	1777.3	0

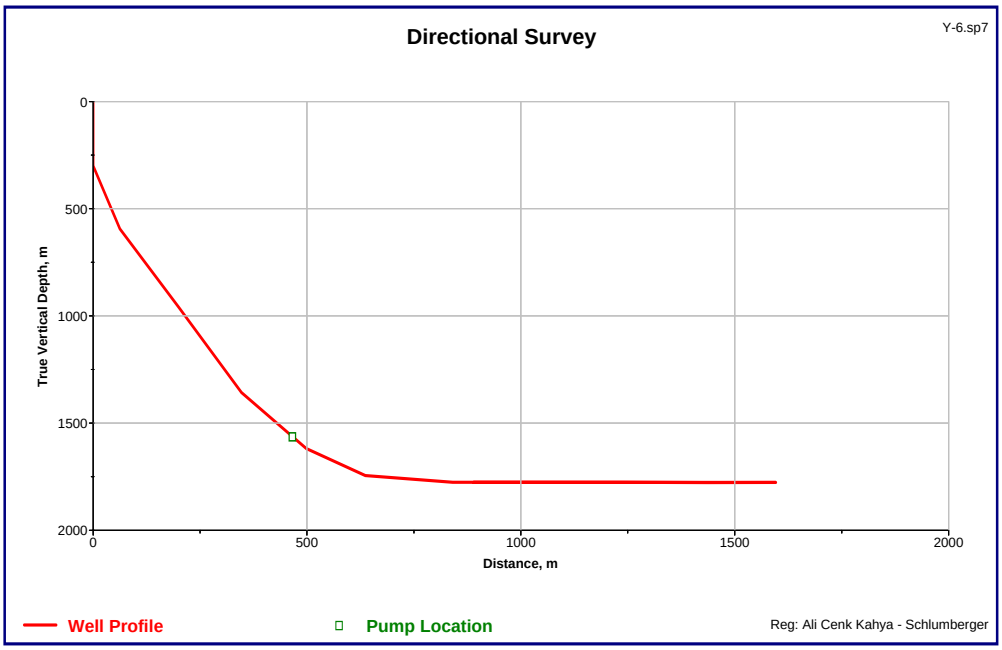

Figure B.6.1 Directional survey profile for Y-6 well

Table B.6.4 Fluid data for Y-6 well

Input Data	
Oil Gravity, g/cc	0.862
SG Gas	0.594
Water Cut, %	93.0
Water Gravity	1.015
Bubble Pt Pressure, atm	110.000
Prod. Gas/Oil Ratio, m3(g)/m3(l)	77.80
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	5.45
Solution GOR, m3(g)/m3(l)	54.75
Average Fluid Viscosity, Pa-s	0.0007197
Fluid Gradient at Pump Intake, psi/ft	0.433

Table B.6.5 Viscosity calibration data for Y-6 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table B.6.6 PVT lab data for Y-6 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
N/A	N/A	N/A

Table B.6.7 Inflow data generated by SubPUMP for Y-6 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	3024
Productivity Index, m3/d/Atm	67.2
Bubble Point Rate, m3/d	4368
Max. Oil Flow Rate, m3/d	8474.7
Max. Total Flow Rate, m3/d	10463.9

Table B.6.8 Design criteria for Y-6 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	3376
Pump Depth, m	1650
Fluid Over Pump, m	1028.8
Pumping Fluid Level, m	621.2
Pump Intake Pressure, atm	103.934
Total Dynamic Head, m	876.9
Tubing Pressure, atm	16
Casing Pressure, atm	12.6
Bottom Hole Pressure, atm	124.762
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	0.21
Natural Gas Separation, %	14
Free Gas into Pump, %	0.18
Gas Separator Installed	No
Gas Separator Efficiency,	0

Table B.6.9 Well system curve detail for Y-6 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	5497.18	5174.4	322.78	66.8	67.9	94.9
2	5420.83	4758.9	661.93	893.1	908.7	222.9
3	5618.62	4339.78	1278.84	1719.4	1749.4	353.3
4	5939.19	3918.72	2020.47	2545.8	2590.1	486.2
5	6367.76	3494.96	2872.79	3372.1	3430.8	620.6
6	6906.05	3070.2	3835.85	4198.5	4271.5	760.4
7	7564.98	2653.65	4911.33	5024.8	5112.2	900.9
8	8349.73	2233.96	6115.78	5851.1	5953	1042.9
PumpOff	10313.1	503.03	9810.03	6677.5	6793.7	1648.4
Design	6370.02	3492.97	2877.05	3376	3434.8	621.2

Table B.6.10 Theoretical pump performance for Y-6 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	269.7	268.5	236.3
Gas Rate through Pump, m3/d	6.2	0	N/A
Gas Rate from Casing, m3/d	1	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	18385.3
Free Gas Percent, %	0.33	0.08	N/A
Water Rate, Bbl/D	19928.3	19856.5	19747.6
Total Liquid Rate, m3/d	3438	3425.5	3375.9
Pressure, atm	103.936	188.72	16
Specific Gravity Liquid, wtr=1	0.99	0.99	N/A
Specific Gravity Mixture, wtr=1	0.99	0.99	N/A
Liquid Density, g/cc	0.989	0.991	N/A
Mixture Density, g/cc	0.986	0.991	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	49.71	51.86	N/A
Solution GWR, m3(g)/m3(l)	1.69	9.72	N/A
Liquid FVF, res/surf	1.02	1.01	N/A
Mixture FVF, res/surf	1.02	1.02	N/A
Gas Deviation Factor	0.854	0.821	N/A

Table B.6.11 Pump data for Y-6 well

Manufacturer	Reda
Series	562
Model	HN21000
Minimum Recommended Rate, m3/d	2550.5**
Maximum Recommended Rate, m3/d	3497.8**
Rate at Peak Efficiency, m3/d	2786.7**
Power at Peak Efficiency, HP	720.1**
Frequency, Hz	55
Number of Stages	85

**Corrected for frequency and viscosity

Table B.6.12 Stage data for Y-6 well generated by SubPUMP

	Design	85 Stages
Total Dynamic Head (TDH), ft	2877.05	2876.88
Surface Rate (O+W), m3/d	3376	3375.9
Avg. Pump Rate (O+G+W), m3/d	N/A	3434.7
Pump Intake Pressure, atm	103.934	103.936
Operating Power, HP	N/A	753.5
Pump Efficiency, %	N/A	59.9

Table B.6.13 Motor data for Y-6 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	900
Name Plate Frequency, Hz	60
Name Plate Voltage, Volts	3720.05
Name Plate Current, Amps	147.4
Adjust for Motor Slip	No
Design Frequency, Hz	55
Operating Motor Load, HP (@ Design Frequency)	753.5
Operating Motor Load,	91.33
Operating Speed, RPM	3188
Operating Current, Amps	135.4
Operating Voltage, Volts	3410.11
Operating Power Factor, frac	0.8
Harmonic Heating due to VSD, °C	9.6
Operating Efficiency, %	87.9
Total Winding Temp., °C	118.6
Fluid Velocity, ft/sec	8.534
Well Fluid Temperature, °C	48.5

Table B.6.14 Protector data for Y-6 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BSLSBSL-HL
Bearing Cap., kg	6237

Table B.6.15 Cable data for Y-6 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Round
Conductor Type	Solid
Max. Cond. Temp., °C	204.4
Cable Length, m	1750
Solve for	Surface Voltage

Table B.6.16 Rate and Efficiency data calculated by SubPUMP for Y-6 well

	Catalog	Actual
Total Stages	85	85
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2876.88	2876.88
Surface Rate (O+W), m3/d	3375.9	3375.9
Avg. Pump Rate (O+G+W), m3/d	3434.7	3434.7
Pump Intake Pressure, atm	103.936	103.936
Operating Power, HP	753.5	753.5
Pump Efficiency, %	59.9	59.9
Operating Speed, RPM	3208	3208

B.7 SubPUMP Software Input and Output Data for Y-7 Well

B.7.1 SubPUMP Software Input and Output Data for Y-7 Well (Current Design)

Table B.7.1.1 Tubing and casing data for Y-7 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	101.60	16.37	88.29	0.016510	2000.0	0.0
Casing 1	177.80	38.69	159.41	0.016510	2160.0	0.0

Table B.7.1.2 Wellbore data for Y-7 well

Pump Depth, m	1825
Top of Perf. (Datum) Depth, m	2144
Bottom Hole Temp, °C	51
Wellhead Temp, °C	30
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.7.1.3 Directional survey data for Y-7 well

No.	MD m	TVD m	Angle Deg
1	10	10	6
2	600	596.8	29.7
3	1000	944.4	32.4
4	1300	1197.8	29.5
5	1521.3	1390.4	35.5
6	1809	1624.6	52.3
7	2002.3	1742.8	81.1
8	2201.9	1773.6	90.1
9	2408.9	1773.3	90.1
10	2644.7	1773	90.3
11	2861.9	1771.9	89.3
12	2942.1	1772.9	0

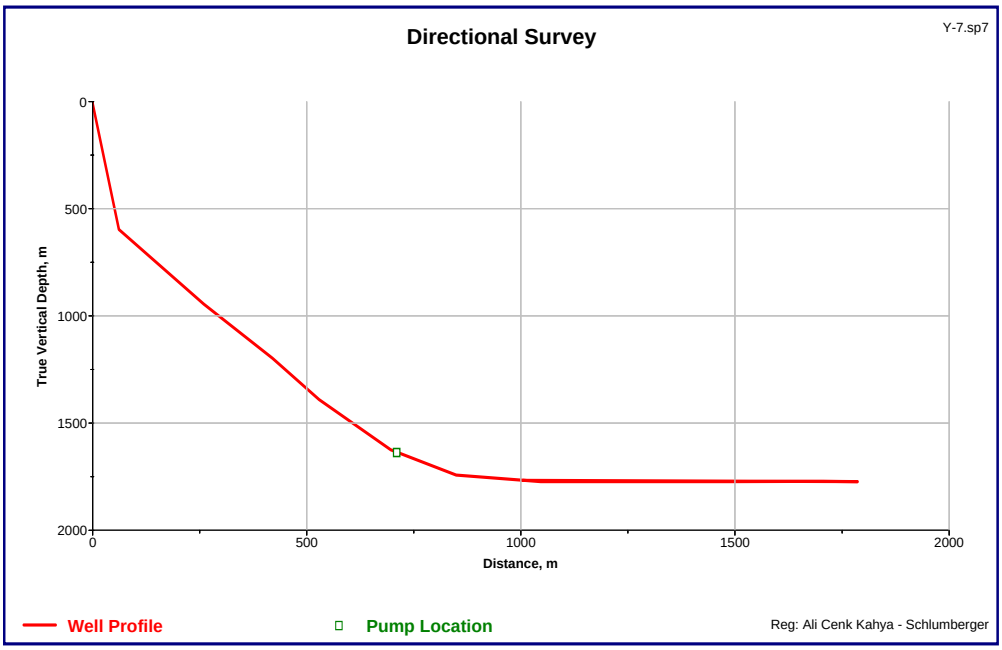

Figure B.7.1 Directional survey profile for Y-7 well

Table B.7.1.4 Fluid data for Y-7 well

Input Data	
Oil Gravity, g/cc	0.862
SG Gas	0.594
Water Cut, %	80.0
Water Gravity	1.015
Bubble Pt Pressure, atm	110.000
Prod. Gas/Oil Ratio, m3(g)/m3(l)	74.70
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	14.94
Solution GOR, m3(g)/m3(l)	54.75
Average Fluid Viscosity, Pa-s	0.0008606
Fluid Gradient at Pump Intake, psi/ft	0.420

Table B.7.1.5 Viscosity calibration data for Y-7 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table B.7.1.6 PVT lab data for Y-7 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
N/A	N/A	N/A

Table B.7.1.7 Inflow data generated by SubPUMP for Y-7 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	1956
Productivity Index, m3/d/Atm	1.07246
Bubble Point Rate, m3/d	7063.3
Max. Oil Flow Rate, m3/d	13704.1
Max. Total Flow Rate, m3/d	15383.1

Table B.7.1.8 Design criteria for Y-7 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	2074
Pump Depth, m	6561.67
Fluid Over Pump, m	1697.3
Pumping Fluid Level, m	302.7
Pump Intake Pressure, atm	148.22
Total Dynamic Head, m	832.8
Tubing Pressure, atm	40
Casing Pressure, atm	14
Bottom Hole Pressure, atm	155.914
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	1.54
Natural Gas Separation, %	20
Free Gas into Pump, %	0
Gas Separator Installed	Yes
Gas Separator Efficiency	70

Table B.7.1.9 Well system curve detail for Y-7 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	6973.14	5990.49	982.64	59.6	61.8	42.3
2	7022.93	5724.59	1298.34	797.4	826.2	124.7
3	7434.32	5410.1	2024.22	1535.2	1590.5	222.2
4	8078.1	5052.32	3025.77	2273	2354.9	333.2
5	8937.69	4651.02	4286.67	3010.8	3119.3	457.9
6	10008.1	4205.64	5802.41	3748.6	3883.7	596.4
7	11299.7	3712.96	7586.74	4486.4	4648.1	770.8
8	12731.3	3165.9	9565.34	5224.2	5412.5	963.2
PumpOff	17511.5	631.48	16880	5962	6176.9	1997
Design	7883.03	5150.78	2732.25	2074	2148.7	302.7

Table B.7.1.10 Theoretical pump performance for Y-7 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	473.2	470.6	411.2
Gas Rate through Pump, m3/d	0	0	N/A
Gas Rate from Casing, m3/d	25.4	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	30719.1
Free Gas Percent, %	0.31	0.21	N/A
Water Rate, Bbl/D	10434.6	10400	10346.3
Total Liquid Rate, m3/d	2132.2	2124.1	2056.2
Pressure, atm	148.473	226.7	40
Specific Gravity Liquid, wtr=1	0.96	0.96	N/A
Specific Gravity Mixture, wtr=1	0.96	0.96	N/A
Liquid Density, g/cc	0.957	0.959	N/A
Mixture Density, g/cc	0.954	0.957	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	55.08	55.08	N/A
Solution GWR, m3(g)/m3(l)	1.79	10.07	N/A
Liquid FVF, res/surf	1.04	1.03	N/A
Mixture FVF, res/surf	1.04	1.03	N/A
Gas Deviation Factor	0.829	0.844	N/A

Table B.7.1.11 Pump data for Y-7 well

Manufacturer	Reda
Series	540
Model	GN10000
Minimum Recommended Rate, m3/d	1199.7**
Maximum Recommended Rate, m3/d	2056.7**
Rate at Peak Efficiency, m3/d	1692.9**
Power at Peak Efficiency, HP	470.3**
Frequency, Hz	66
Number of Stages	116

**Corrected for frequency and viscosity

Table B.7.1.12 Stage data for Y-7 well generated by SubPUMP

	Design	116 Stages
Total Dynamic Head (TDH), ft	2732.25	2708.76
Surface Rate (O+W), m3/d	2074	2056.2
Avg. Pump Rate (O+G+W), m3/d	N/A	2130.3
Pump Intake Pressure, atm	148.22	148.473
Operating Power, HP	N/A	444.9
Pump Efficiency, %	N/A	59.5

Table B.7.1.13 Motor data for Y-7 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	630
Name Plate Frequency, Hz	60
Name Plate Voltage, Volts	3262.02
Name Plate Current, Amps	113.3
Adjust for Motor Slip	No
Design Frequency, Hz	66
Operating Motor Load, HP (@ Design Frequency)	444.9
Operating Motor Load,	70.62
Operating Speed, RPM	3845
Operating Current, Amps	81.6
Operating Voltage, Volts	3588.27
Operating Power Factor, frac	0.745
Harmonic Heating due to VSD, °C	4.8
Operating Efficiency, %	87.9
Total Winding Temp., °C	79.8
Fluid Velocity, ft/sec	19.748
Well Fluid Temperature, °C	50.7

Table B.7.1.14 Protector data for Y-7 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BSLSBSL-HL
Bearing Cap., kg	6803.9

Table B.7.1.15 Cable data for Y-7 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Solid
Max. Cond. Temp., °C	232.2
Solve for	Surface Voltage

Table B.7.1.16 Rate and Efficiency data calculated by SubPUMP for Y-7 well

	Catalog	Actual
Total Stages	116	116
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2708.76	2708.76
Surface Rate (O+W), m3/d	2056.2	2056.2
Avg. Pump Rate (O+G+W), m3/d	2130.3	2130.3
Pump Intake Pressure, atm	148.473	148.473
Operating Power, HP	444.9	438.3
Pump Efficiency, %	59.5	59.5
Operating Speed, RPM	3850	3850

B.7.2 SubPUMP Software Input and Output Data for Y-7 Well (Recommended Design)

Table B.7.2.1 Design criteria for Y-7 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	2000
Pump Depth, m	5987.52
Fluid Over Pump, m	1387.4
Pumping Fluid Level, m	437.6
Pump Intake Pressure, atm	139.408
Total Dynamic Head, m	600.9
Tubing Pressure, atm	23
Casing Pressure, atm	25
Bottom Hole Pressure, atm	154.245
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	0.52
Natural Gas Separation, %	20
Free Gas into Pump, %	0
Gas Separator Installed	Yes
Gas Separator Efficiency,	70

Table B.7.2.2 Well system curve detail for Y-7 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	6009.22	5528.34	480.88	59.6	61	194.8
2	5997.84	5253.16	744.68	797.4	816.4	280.9
3	6371.42	4953.58	1417.84	1535.2	1571.8	374.7
4	6964.88	4632.17	2332.71	2273	2327.2	475.4
5	7745.59	4289.13	3456.46	3010.8	3082.6	583
6	8718.37	3924.33	4794.04	3748.6	3838	711.6
7	9887.92	3535.38	6352.54	4486.4	4593.4	850.6
8	11201.2	3122.06	8079.17	5224.2	5348.8	998.1
PumpOff	13660.7	1003.99	12656.8	5962	6104.2	1819.5
Design	6724.28	4752.67	1971.61	2000	2047.7	437.6

Table B.7.2.3 Theoretical pump performance for Y-7 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	298.4	297	260.1
Gas Rate through Pump, m3/d	0	0	N/A
Gas Rate from Casing, m3/d	8.9	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	19427.6
Free Gas Percent, %	0.2	0.14	N/A
Water Rate, Bbl/D	12094.9	12065	11996
Total Liquid Rate, m3/d	2221.3	2215.2	2167.3
Pressure, atm	137.302	193.845	23
Specific Gravity Liquid, wtr=1	0.98	0.98	N/A
Specific Gravity Mixture, wtr=1	0.98	0.98	N/A
Liquid Density, g/cc	0.977	0.979	N/A
Mixture Density, g/cc	0.975	0.978	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	53.98	53.98	N/A
Solution GWR, m3(g)/m3(l)	1.77	9.95	N/A
Liquid FVF, res/surf	1.02	1.02	N/A
Mixture FVF, res/surf	1.03	1.02	N/A
Gas Deviation Factor	0.831	0.827	N/A

Table B.7.2.4 Pump data for Y-7 well

Manufacturer	Reda
Series	562
Model	HN13500
Minimum Recommended Rate, m3/d	699.2**
Maximum Recommended Rate, m3/d	2517.3**
Rate at Peak Efficiency, m3/d	1826.4**
Power at Peak Efficiency, HP	391.5**
Frequency, Hz	53
Number of Stages	90

**Corrected for frequency and viscosity

Table B.7.2.5 Stage data for Y-7 well generated by SubPUMP

	Design	90 Stages
Total Dynamic Head (TDH), ft	1971.61	2206.97
Surface Rate (O+W), m3/d	2000	2178.5
Avg. Pump Rate (O+G+W), m3/d	N/A	2230.4
Pump Intake Pressure, atm	139.408	137.161
Operating Power, HP	N/A	350
Pump Efficiency, %	N/A	67.2

Table B.7.2.6 Motor data for Y-7 well generated by SubPUMP

Manufacturer	Reda
Series	540
Name Plate Power, HP	S - Triple
Name Plate Frequency, Hz	675
Name Plate Voltage, Volts	60
Name Plate Current, Amps	3000
Adjust for Motor Slip	133
Design Frequency, Hz	Yes
Operating Motor Load, HP (@ Design Frequency)	53
Operating Motor Load,	350
Operating Speed, RPM	58.7
Operating Current, Amps	3079
Operating Voltage, Volts	87.4
Operating Power Factor, frac	2650.05
Harmonic Heating due to VSD, °C	0
Operating Efficiency, %	0.779
Total Winding Temp., °C	4.7
Fluid Velocity, ft/sec	81.44
Well Fluid Temperature, °C	78.2

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Table B.7.2.7 Protector data for Y-7 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BSLSBSL-HL
Bearing Cap., kg	6010.2

Table B.7.2.8 Cable data for Y-7 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Solid
Max. Cond. Temp., °C	232.2
Cable Length, m	1855.48
Solve for	Surface Voltage

Table B.7.2.9 Rate and Efficiency data calculated by SubPUMP for Y-7 well

	Catalog	Actual
Total Stages	90	90
Slip Stages	0	0
Total Dynamic Head (TDH), ft	2206.97	2193.85
Surface Rate (O+W), m3/d	2178.5	2167.3
Avg. Pump Rate (O+G+W), m3/d	2230.4	2219
Pump Intake Pressure, atm	137.161	137.302
Operating Power, HP	350	346.6
Pump Efficiency, %	67.2	63.7
Operating Speed, RPM	3091	3078

B.8 SubPUMP Software Input and Output Data for Y-8 Well

B.8.1 SubPUMP Software Input and Output Data for Y-8 Well (Current Design)

Table B.8.1.1 Tubing and casing data for Y-8 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	88.90	19.27	69.85	0.016510	1908.0	0.0
Casing 1	219.08	53.57	198.76	0.016510	2150.0	0.0
Casing 2	127.00	22.32	111.96	0.016510	3065.0	2150.0

Table B.8.1.2 Wellbore data for Y-8 well

Pump Depth, m	1908
Top of Perf. (Datum) Depth, m	2177
Bottom Hole Temp, °C	61
Wellhead Temp, °C	20
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.8.1.3 Directional survey data for Y-8 well

No.	MD m	TVD m	Angle Deg
1	100	100	5.4
2	552	550	16.6
3	736.7	727	17.2
4	1077	1052	24.3
5	1528	1463	15.5
6	1666	1596	19.8
7	1784	1707	35.3
8	1809.6	1727.9	32
9	1858.1	1769	43.4
10	1993	1867	73.1
11	2151	1913	88.6
12	2305.9	1916.7	90.1
13	2790	1916	89.6
14	3064.6	1917.7	0

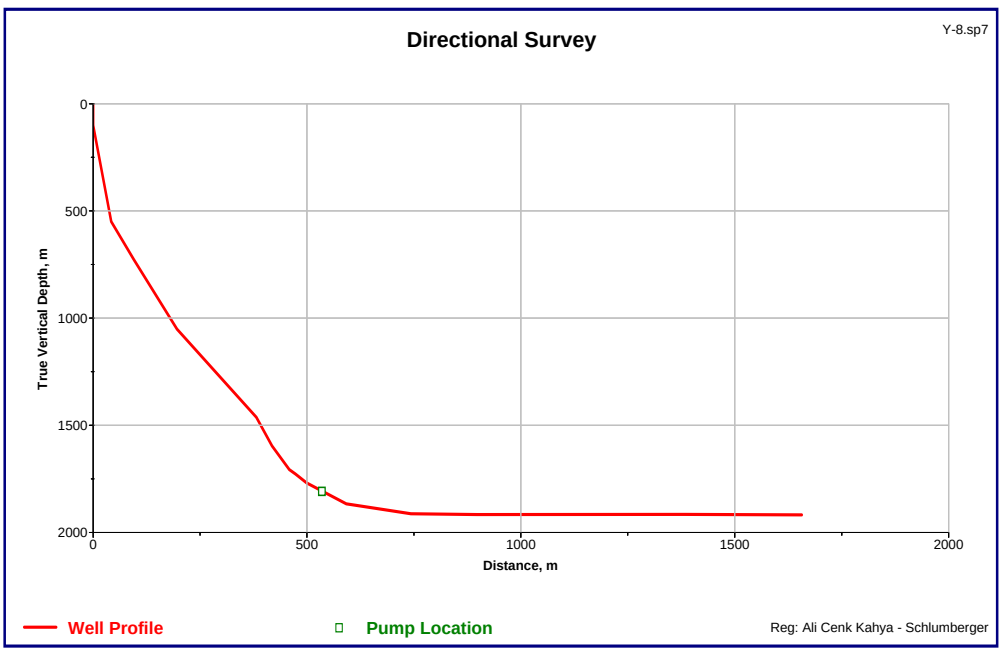

Figure B.8.1 Directional survey profile for Y-8 well

Table B.8.1.4 Fluid data for Y-8 well

Input Data	
Oil Gravity, g/cc	0.837
SG Gas	0.620
Water Cut, %	15
Water Gravity	1.015
Bubble Pt Pressure, atm	107.000
Prod. Gas/Oil Ratio, m3(g)/m3(l)	63.88
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	54.29
Solution GOR, m3(g)/m3(l)	54.55
Average Fluid Viscosity, Pa-s	0.0013820
Fluid Gradient at Pump Intake, psi/ft	0.314

Table B.8.1.5 Viscosity calibration data for Y-8 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	199	61	0.00111	Sat.	0.00092	1.207

Table B.8.1.6 PVT lab data for Y-8 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
61	199	1.1100

Table B.8.1.7 Inflow data generated by SubPUMP for Y-8 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	732
Productivity Index, m3/d/Atm	149.964
Bubble Point Rate, m3/d	0
Max. Oil Flow Rate, m3/d	6665
Max. Total Flow Rate, m3/d	6769.6

Table B.8.1.8 Design criteria for Y-8 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	732
Pump Depth, m	1908
Fluid Over Pump, m	834.7
Pumping Fluid Level, m	1073.3
Pump Intake Pressure, atm	68.019
Total Dynamic Head, m	1029
Tubing Pressure, atm	11.5
Casing Pressure, atm	9.4
Bottom Hole Pressure, atm	74.985
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	26.66
Natural Gas Separation, %	20
Free Gas into Pump, %	8.02
Gas Separator Installed	Yes
Gas Separator Efficiency,	70

Table B.8.1.9 Well system curve detail for Y-8 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	5179.68	3062.57	2117.11	62.3	70.7	1029
2	6574.7	2931.84	3642.86	832.8	945	1080.9
3	8928.49	2750.67	6177.82	1603.4	1819.4	1155.7
4	12144.1	2545.82	9598.3	2373.9	2693.7	1239.7
5	16444.3	2318.43	14125.9	3144.5	3568.1	1331.9
6	22191	2059.84	20131.2	3915	4442.5	1434.6
7	29962.7	1750.04	28212.7	4685.5	5316.8	1551.4
8	40806.6	1347.31	39459.3	5456.1	6191.2	1686.4
PumpOff	59175.4	647.15	58528.3	6226.6	7065.6	1906.3
Design	6326.58	2950.61	3375.97	732	830.6	1073.3

Table B.8.1.10 Theoretical pump performance for Y-8 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	706.2	713	620.9
Gas Rate through Pump, m3/d	71.3	0	N/A
Gas Rate from Casing, m3/d	225.8	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	39662.2
Free Gas Percent, %	8.02	0	N/A
Water Rate, Bbl/D	699.58	697.45	689.21
Total Liquid Rate, m3/d	817.4	823.8	730.5
Pressure, atm	68.027	144.717	11.5
Specific Gravity Liquid, wtr=1	0.81	0.8	N/A
Specific Gravity Mixture, wtr=1	0.75	0.8	N/A
Liquid Density, g/cc	0.808	0.795	N/A
Mixture Density, g/cc	0.747	0.795	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	32.2	39.72	N/A
Solution GWR, m3(g)/m3(l)	1.21	7.69	N/A
Liquid FVF, res/surf	1.12	1.13	N/A
Mixture FVF, res/surf	1.22	1.13	N/A
Gas Deviation Factor	0.9	0.847	N/A

Table B.8.1.11 Pump data for Y-8 well

Manufacturer	Reda
Series	538
Model	S5000N
Minimum Recommended Rate, m3/d	372.2**
Maximum Recommended Rate, m3/d	717.7**
Rate at Peak Efficiency, m3/d	714.0**
Power at Peak Efficiency, HP	362.6**
Frequency, Hz	57
Number of Stages	207

**Corrected for frequency and viscosity

Table B.8.1.12 Stage data for Y-8 well generated by SubPUMP

	Design	207 Stages
Total Dynamic Head (TDH), ft	3375.97	3373.29
Surface Rate (O+W), m3/d	732	730.5
Avg. Pump Rate (O+G+W), m3/d	N/A	828.9
Pump Intake Pressure, atm	68.019	68.027
Operating Power, HP	N/A	283.7
Pump Efficiency, %	N/A	46

Table B.8.1.13 Motor data for Y-8 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	500
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	2603.06
Name Plate Current, Amps	113.4
Adjust for Motor Slip	No
Design Frequency, Hz	57
Operating Motor Load, HP (@ Design Frequency)	283.7
Operating Motor Load,	49.78
Operating Speed, RPM	3316
Operating Current, Amps	71.9
Operating Voltage, Volts	2967.54
Operating Power Factor, frac	0.651
Harmonic Heating due to VSD, °C	4.3
Operating Efficiency, %	87.9
Total Winding Temp., °C	93.2
Fluid Velocity, ft/sec	1.847
Well Fluid Temperature, °C	58.7

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Table B.8.1.14 Protector data for Y-8 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BPBSL-HL
Bearing Cap., kg	6463.8

Table B.8.1.15 Cable data for Y-8 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Solve for	Surface Voltage

Table B.8.1.16 Rate and Efficiency data calculated by SubPUMP for Y-8 well

	Catalog	Actual
Total Stages	207	207
Slip Stages	0	0
Total Dynamic Head (TDH), ft	3373.29	3373.29
Surface Rate (O+W), m3/d	730.5	730.5
Avg. Pump Rate (O+G+W), m3/d	828.9	828.9
Pump Intake Pressure, atm	68.027	68.027
Operating Power, HP	283.7	279.5
Pump Efficiency, %	46	46
Operating Speed, RPM	3325	3325

B.8.2 SubPUMP Software Input and Output Data for Y-8 Well (Recommended Design)

Table B.8.2.1 Design criteria for Y-8 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	690
Pump Depth, m	1908
Fluid Over Pump, m	310.4
Pumping Fluid Level, m	1597.6
Pump Intake Pressure, atm	34.347
Total Dynamic Head, m	1923.6
Tubing Pressure, atm	12.5
Casing Pressure, atm	10.8
Bottom Hole Pressure, atm	39.526
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	47.64
Natural Gas Separation, %	35
Free Gas into Pump, %	15.07
Gas Separator Installed	Yes
Gas Separator Efficiency,	70

Table B.8.2.2 Well system curve detail for Y-8 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	6548.41	2832.15	3716.26	9.1	9.8	1110.5
2	5888.79	2651.97	3236.83	121.3	131.1	1181.2
3	6137.35	2465.94	3671.41	233.5	252.4	1254.5
4	6445.46	2269.8	4175.66	345.8	373.6	1331.9
5	6823.65	2057.49	4766.16	458	494.9	1415.2
6	7283.71	1825.14	5458.57	570.3	616.2	1505.2
7	7836.19	1589.85	6246.34	682.5	737.5	1590.8
8	8688.96	1256.02	7432.94	794.8	858.8	1705.9
PumpOff	10574.1	667.07	9907.02	907	980	1906.1
Design	7881.59	1570.51	6311.08	690	745.6	1597.6

Table B.8.2.3 Theoretical pump performance for Y-8 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	470.9	477.3	432.1
Gas Rate through Pump, m3/d	131.3	0	N/A
Gas Rate from Casing, m3/d	542	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	27656.8
Free Gas Percent, %	15.34	0	N/A
Water Rate, Bbl/D	1692.12	1683.13	1665.91
Total Liquid Rate, m3/d	739.9	744.9	697
Pressure, atm	33.853	165.873	12.5
Specific Gravity Liquid, wtr=1	0.87	0.86	N/A
Specific Gravity Mixture, wtr=1	0.74	0.86	N/A
Liquid Density, g/cc	0.869	0.86	N/A
Mixture Density, g/cc	0.739	0.86	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	14.06	23.56	N/A
Solution GWR, m3(g)/m3(l)	0.78	5.71	N/A
Liquid FVF, res/surf	1.06	1.07	N/A
Mixture FVF, res/surf	1.25	1.07	N/A
Gas Deviation Factor	0.947	0.855	N/A

Table B.8.2.4 Pump data for Y-8 well

Manufacturer	Reda
Series	540
Model	GN5600
Minimum Recommended Rate, m3/d	575.2**
Maximum Recommended Rate, m3/d	1078.5**
Rate at Peak Efficiency, m3/d	1092.9**
Power at Peak Efficiency, HP	522.4**
Frequency, Hz	67
Number of Stages	210

**Corrected for frequency and viscosity

Table B.8.2.5 Stage data for Y-8 well generated by SubPUMP

	Design	210 Stages
Total Dynamic Head (TDH), ft	6311.08	6386.3
Surface Rate (O+W), m3/d	690	697
Avg. Pump Rate (O+G+W), m3/d	N/A	753.1
Pump Intake Pressure, atm	34.347	33.853
Operating Power, HP	N/A	416.2
Pump Efficiency, %	N/A	41.1

Table B.8.2.6 Motor data for Y-8 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	580
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	3095.48
Name Plate Current, Amps	110.1
Adjust for Motor Slip	No
Design Frequency, Hz	67
Operating Motor Load, HP (@ Design Frequency)	416.2
Operating Motor Load,	59.81
Operating Speed, RPM	3900
Operating Current, Amps	72.6
Operating Voltage, Volts	4147.94
Operating Power Factor, frac	0.678
Harmonic Heating due to VSD, °C	4.7
Operating Efficiency, %	87.9
Total Winding Temp., °C	96.3
Fluid Velocity, ft/sec	1.762
Well Fluid Temperature, °C	58.7

Table B.8.2.7 Protector data for Y-8 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BPBSL-HL
Bearing Cap., kg	6803.9

Table B.8.2.8 Cable data for Y-8 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2008
Solve for	Surface Voltage

Table B.8.2.9 Rate and Efficiency data calculated by SubPUMP for Y-8 well

	Catalog	Actual
Total Stages	210	210
Slip Stages	0	0
Total Dynamic Head (TDH), ft	6386.3	6386.3
Surface Rate (O+W), m^3/d	697	697
Avg. Pump Rate (O+G+W), m3/d	753.1	753.1
Pump Intake Pressure, atm	33.853	33.853
Operating Power, HP	416.2	409.3
Pump Efficiency, %	41.1	41.1
Operating Speed, RPM	3908	3908

B.9 SubPUMP Software Input and Output Data for Y-9 Well

Table B.9.1 Tubing and casing data for Y-9 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	88.90	13.84	76.00	0.016510	1740.0	0.0
Casing 1	177.80	43.16	157.07	0.016510	2444.0	0.0

Table B.9.2 Wellbore data for Y-9 well

Pump Depth, m	1740
Top of Perf. (Datum) Depth, m	1806
Bottom Hole Temp, °C	51
Wellhead Temp, °C	20
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.9.3 Directional survey data for Y-9 well

No.	MD m	TVD m	Angle Deg
1	10	10	1.5
2	500	499.8	9.4
3	1000	993.1	15.9
4	1500	1474.1	14.2
5	2000	1958.9	18.7
6	2500	2432.6	18.1
7	2880	2793.8	0

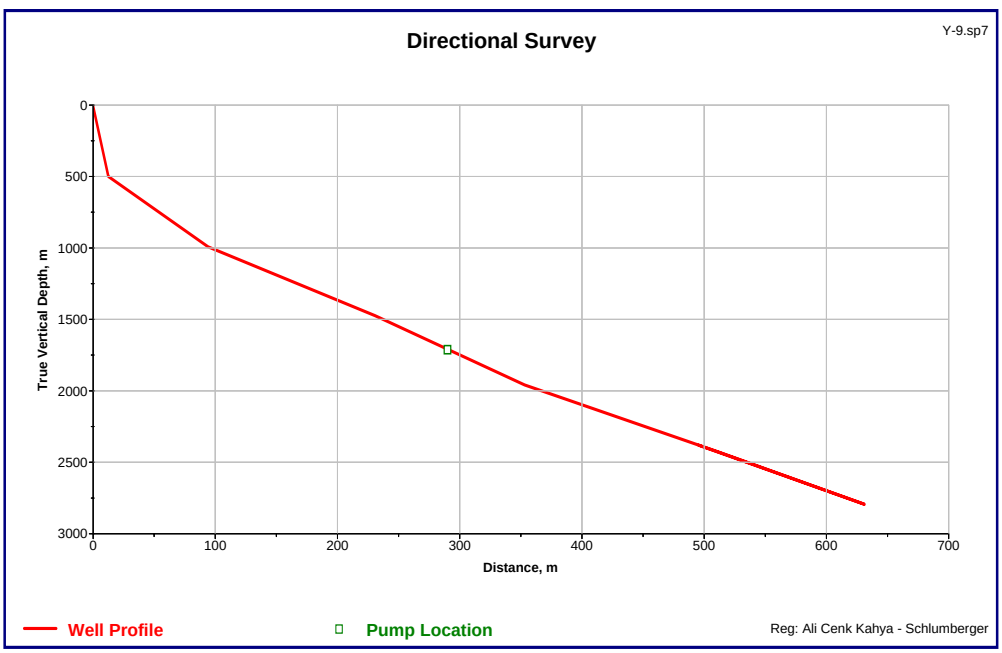

Figure B.9.1 Directional survey profile for Y-9 well

Table B.9.4 Fluid data for Y-9 well

Input Data	
Oil Gravity, g/cc	0.862
SG Gas	0.594
Water Cut, %	90
Water Gravity	1.015
Bubble Pt Pressure, atm	110.000
Prod. Gas/Oil Ratio, m3(g)/m3(l)	62.00
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	6.20
Solution GOR, m3(g)/m3(l)	46.25
Average Fluid Viscosity, Pa-s	2.4
Fluid Gradient at Pump Intake, psi/ft	0.426

Table B.9.5 Viscosity calibration data for Y-9 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	1	20	4.3	Dead	54	0.08

Table B.9.6 PVT lab data for Y-9 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
51	110	1.5700
51	175	1.9600

Table B.9.7 Inflow data generated by SubPUMP for Y-9 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	1494
Productivity Index, m3/d/Atm	15.444
Bubble Point Rate, m3/d	1235.5
Max. Oil Flow Rate, m3/d	2179.3
Max. Total Flow Rate, m3/d	2565

Table B.9.8 Design criteria for Y-9 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	1517
Pump Depth, m	1740
Fluid Over Pump, m	582.4
Pumping Fluid Level, m	1157.6
Pump Intake Pressure, atm	80.549
Total Dynamic Head, m	1439.6
Tubing Pressure, atm	26
Casing Pressure, atm	25
Bottom Hole Pressure, atm	91.614
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	2.03
Natural Gas Separation, %	18.6
Free Gas into Pump, %	0.67
Gas Separator Installed	Yes
Gas Separator Efficiency,	60

Table B.9.9 Well system curve detail for Y-9 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	6361.81	6204.53	157.28	21.6	22	61
2	6295.15	5604.77	690.39	289.1	294.8	246.7
3	6410.32	4994.25	1416.06	556.6	567.6	436
4	6600.16	4374.32	2225.84	824.1	840.4	630.4
5	6855.01	3745.25	3109.76	1091.5	1113.2	828.9
6	7196.68	3106	4090.68	1359	1386	1032
7	7637.41	2461.01	5176.4	1626.5	1658.8	1246.6
8	8176.81	1785.41	6391.39	1894	1931.6	1473
PumpOff	9023.78	995.74	8028.05	2161.5	2204.4	1737
Design	7451.09	2728.05	4723.04	1517	1547.2	1157.6

Table B.9.10 Theoretical pump performance for Y-9 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	170.2	170.6	151.7
Gas Rate through Pump, m3/d	10.4	0	N/A
Gas Rate from Casing, m3/d	21.6	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	9402.8
Free Gas Percent, %	0.67	0	N/A
Water Rate, Bbl/D	8673.51	8624.49	8585.09
Total Liquid Rate, m3/d	1549.2	1541.8	1516.6
Pressure, atm	80.58	218.354	26
Specific Gravity Liquid, wtr=1	0.98	0.99	N/A
Specific Gravity Mixture, wtr=1	0.98	0.99	N/A
Liquid Density, g/cc	0.983	0.986	N/A
Mixture Density, g/cc	0.977	0.986	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	32.11	36.69	N/A
Solution GWR, m3(g)/m3(l)	1.41	8.53	N/A
Liquid FVF, res/surf	1.02	1.02	N/A
Mixture FVF, res/surf	1.03	1.02	N/A
Gas Deviation Factor	0.881	0.853	N/A

Table B.9.11 Pump data for Y-9 well

Manufacturer	Reda
Series	538
Model	SN8500
Minimum Recommended Rate, m3/d	890.3**
Maximum Recommended Rate, m3/d	1632.3**
Rate at Peak Efficiency, m3/d	1261.3**
Power at Peak Efficiency, HP	485.9**
Frequency, Hz	56
Number of Stages	189

**Corrected for frequency and viscosity

Table B.9.12 Stage data for Y-9 well generated by SubPUMP

	Design	189 Stages
Total Dynamic Head (TDH), ft	4723.04	4720.37
Surface Rate (O+W), m3/d	1517	1516.6
Avg. Pump Rate (O+G+W), m3/d	N/A	1546.7
Pump Intake Pressure, atm	80.549	80.58
Operating Power, HP	N/A	488.6
Pump Efficiency, %	N/A	68

Table B.9.13 Motor data for Y-9 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	525
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	3013.93
Name Plate Current, Amps	100.8
Adjust for Motor Slip	No
Design Frequency, Hz	56
Operating Motor Load, HP (@ Design Frequency)	488.6
Operating Motor Load,	83.09
Operating Speed, RPM	3262
Operating Current, Amps	87.7
Operating Voltage, Volts	3375.66
Operating Power Factor, frac	0.808
Harmonic Heating due to VSD, °C	5.4
Operating Efficiency, %	87.9
Total Winding Temp., °C	82.8
Fluid Velocity, ft/sec	17.078
Well Fluid Temperature, °C	49.9

Table B.9.14 Protector data for Y-9 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BPBSL-HL
Bearing Cap., kg	6350.4

Table B.9.15 Cable data for Y-9 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Solve for	Surface Voltage

Table B.9.16 Rate and Efficiency data calculated by SubPUMP for Y-9 well

	Catalog	Actual
Total Stages	189	189
Slip Stages	0	0
Total Dynamic Head (TDH), ft	4720.37	4720.37
Surface Rate (O+W), m3/d	1516.6	1516.6
Avg. Pump Rate (O+G+W), m3/d	1546.7	1546.7
Pump Intake Pressure, atm	80.58	80.58
Operating Power, HP	488.6	484.5
Pump Efficiency, %	68	68
Operating Speed, RPM	3266	3266

B.10 SubPUMP Software Input and Output Data for Y-10 Well

Table B.10.1 Tubing and casing data for Y-10 well

	OD mm	Wt kg/m	ID mm	Rough. mm	Bottom m	Top m
Tubing 1	89.00	0.00	76.00	0.016510	1920.0	0.0
Casing 1	178.00	0.00	159.00	0.016510	345.0	0.0
Casing 2	178.00	0.00	162.00	0.016510	2300.0	0.0

Table B.10.2 Wellbore data for Y-10 well

Pump Depth, m	1920
Top of Perf. (Datum) Depth, m	2244
Bottom Hole Temp, °C	72
Wellhead Temp, °C	20
Outflow Correlation Method	Hagedorn & Brown (1963)

Table B.10.3 Directional survey data for Y-10 well

No.	MD m	TVD m	Angle Deg
1	10	10	7.7
2	120	119	4.1
3	510	508	14.4
4	890	876	13.8
5	1410	1381	15.2
6	2300	2240	0

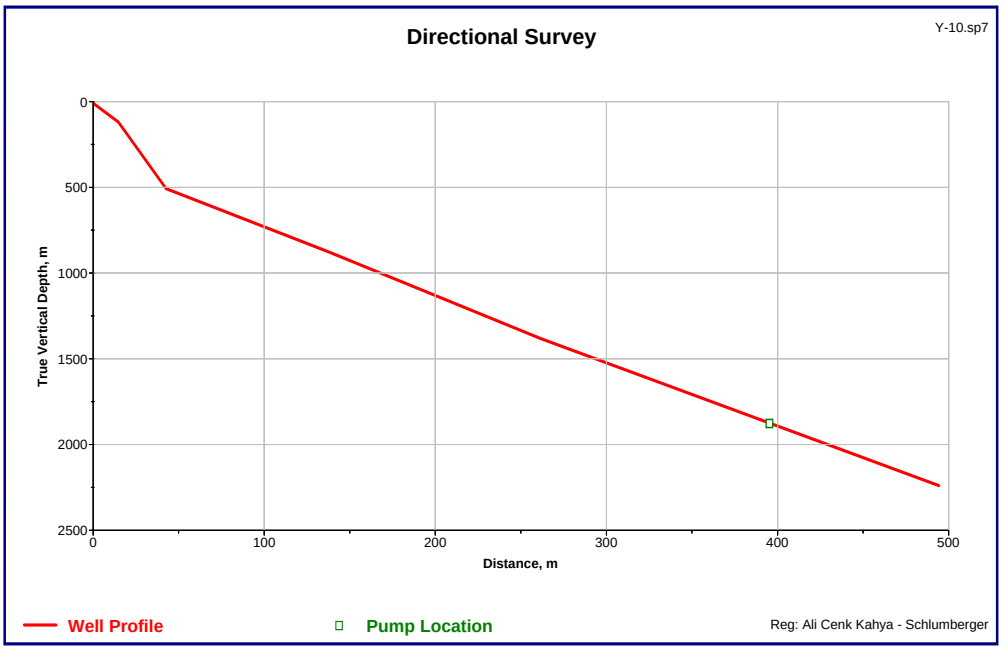

Figure B.10.1 Directional survey profile for Y-10 well

Table B.10.4 Fluid data for Y-10 well

Input Data	
Oil Gravity, g/cc	0.837
SG Gas	0.620
Water Cut, %	94
Water Gravity	1.015
Bubble Pt Pressure, atm	11.800
Prod. Gas/Oil Ratio, m3(g)/m3(l)	300.00
OutputData	
Prod. Gas/Liq. Ratio, m3(g)/m3(l)	18.00
Solution GOR, m3(g)/m3(l)	54.79
Average Fluid Viscosity, Pa-s	0.0011946
Fluid Gradient at Pump Intake, psi/ft	0.426

Table B.10.5 Viscosity calibration data for Y-10 well

Pnt. #	Press. Atm.	Temp. °C	User Viscosity Pa-s	Type	Calculated Viscosity Pa-s	Calibration Factor
1	1	20	0.00329	Dead	0.02326	0.141

Table B.10.6 PVT lab data for Y-10 well

PVT Temperature, °C	Pressure atm	Oil Viscosity cp
72	111.800	0.7600
72	225.000	0.9600

Table B.10.7 Inflow data generated by SubPUMP for Y-10 well

IPR Calculation Method	Vogel Corrected for Water Cut
Fluid Rate at Test BHP, m3/d	965
Productivity Index, m3/d/Atm	8.10979
Bubble Point Rate, m3/d	918
Max. Oil Flow Rate, m3/d	1421.7
Max. Total Flow Rate, m3/d	1682.5

Table B.10.8 Design criteria for Y-10 well, solved for Pump Intake Conditions

Total Fluid Rate, m3/d	1047
Pump Depth, m	1920
Fluid Over Pump, m	612.8
Pumping Fluid Level, m	1307.2
Pump Intake Pressure, atm	69.431
Total Dynamic Head, m	1333.4
Tubing Pressure, atm	13
Casing Pressure, atm	12
Bottom Hole Pressure, atm	95.82
Gas through Pump	Gas Into Solution
Packer Installed	No
Free Gas Avail. at Pump, %	18.17
Natural Gas Separation, %	30
Free Gas into Pump, %	5.57
Gas Separator Installed	Yes
Gas Separator Efficiency,	62

Table B.10.9 Well system curve detail for Y-10 well generated by SubPUMP

Point #	(+) Tubing Head ft	(-) PIP Head ft	(=) TDH ft	Surface Rate O+W m3/d	Avg. Pump Rate O+W+G m3/d	Pumping Fluid Level m
1	6404.57	6559.91	-155.34	15	15.6	-17.4
2	6027.47	5800.28	227.19	200	208.9	215
3	6070.2	5034.66	1035.54	385.1	402.3	449.9
4	6165.65	4266.66	1898.99	570.2	595.6	691.6
5	6320.27	3497.52	2822.75	755.2	788.9	935.7
6	6557.69	2764.29	3793.39	940.3	982.2	1171.6
7	6863.36	2037.28	4826.08	1125.4	1175.5	1408.8
8	7280.63	1307.77	5972.86	1310.4	1368.9	1649.7
PumpOff	8283	491.45	7791.56	1495.5	1562.2	1918.6
Design	6722.92	2348.14	4374.79	1047	1093.7	1307.2

Table B.10.10 Theoretical pump performance for Y-10 well created by SubPUMP

	INTAKE	DISCHARGE	SURFACE
Oil Rate, m3/d	71.9	80.1	62.8
Gas Rate through Pump, m3/d	63.4	0	N/A
Gas Rate from Casing, m3/d	175	N/A	N/A
Total Gas Rate, m3/d	N/A	N/A	18851.1
Free Gas Percent, %	5.58	0	N/A
Water Rate, Bbl/D	6304.93	6282.62	6191.97
Total Liquid Rate, m3/d	1074.3	1078.9	1047.3
Pressure, atm	69.398	196.828	13
Specific Gravity Liquid, wtr=1	0.98	0.98	N/A
Specific Gravity Mixture, wtr=1	0.93	0.98	N/A
Liquid Density, g/cc	0.981	0.98	N/A
Mixture Density, g/cc	0.93	0.98	N/A
Mixture Viscosity, CST	N/A	N/A	N/A
Mixture Viscosity, SSU	N/A	N/A	N/A
Solution GOR, m3(g)/m3(l)	32.12	84.2	N/A
Solution GWR, m3(g)/m3(l)	1.21	11.84	N/A
Liquid FVF, res/surf	1.03	1.03	N/A
Mixture FVF, res/surf	1.09	1.03	N/A
Gas Deviation Factor	0.905	0.862	N/A

Table B.10.11 Pump data for Y-10 well

Manufacturer	Reda
Series	538
Model	SN8500
Minimum Recommended Rate, m3/d	731.4**
Maximum Recommended Rate, m3/d	1340.8**
Rate at Peak Efficiency, m3/d	1126.2**
Power at Peak Efficiency, HP	258.0**
Frequency, Hz	50
Number of Stages	189

**Corrected for frequency and viscosity

Table B.10.12 Stage data for Y-10 well generated by SubPUMP

	Design	189 Stages
Total Dynamic Head (TDH), ft	4374.79	4375.47
Surface Rate (O+W), m3/d	1047	1047.3
Avg. Pump Rate (O+G+W), m3/d	N/A	1094
Pump Intake Pressure, atm	69.431	69.398
Operating Power, HP	N/A	250.5
Pump Efficiency, %	N/A	63

Table B.10.13 Motor data for Y-10 well generated by SubPUMP

Manufacturer	Reda
Series	562
Name Plate Power, HP	391.6
Name Plate Frequency, Hz	50
Name Plate Voltage, Volts	3013.93
Name Plate Current, Amps	100.8
Adjust for Motor Slip	No
Design Frequency, Hz	50
Operating Motor Load, HP (@ Design Frequency)	250.5
Operating Motor Load,	63.95
Operating Speed, RPM	2913
Operating Current, Amps	73.4
Operating Voltage, Volts	3013.99
Operating Power Factor, frac	0.743
Harmonic Heating due to VSD, °C	4.5
Operating Efficiency, %	87.9
Total Winding Temp., °C	91.9
Fluid Velocity, ft/sec	8.631
Well Fluid Temperature, °C	64.6

Table B.10.14 Protector data for Y-10 well

Manufacturer	Reda
Series	540
Bearing Type	540 HL
Chamber Selection	BPBSL-HL
Bearing Cap., kg	5670

Table B.10.15 Cable data for Y-10 well

Manufacturer	Reda
Type	Redalead
Size	2 Cu
Shape	Flat
Conductor Type	Stranded
Max. Cond. Temp., °C	232.2
Cable Length, m	2020
Solve for	Surface Voltage

Table B.10.16 Rate and Efficiency data calculated by SubPUMP for Y-10 well

	Catalog	Actual
Total Stages	189	189
Slip Stages	0	0
Total Dynamic Head (TDH), ft	4375.47	4375.47
Surface Rate (O+W), m3/d	1047.3	1047.3
Avg. Pump Rate (O+G+W), m3/d	1094	1094
Pump Intake Pressure, atm	69.398	69.398
Operating Power, HP	250.5	248.3
Pump Efficiency, %	63	63
Operating Speed, RPM	2916	2916

APPENDIX C

SUBPUMP TECHNICAL LIMITS

Table C.1 SubPUMP design limits

Bubble pt press	Std Press to 99999.0 psia
Bubble Pt Press.Standard pressure	+1 to 100000
Casing Bottom	1.0 to 45000 feet.
Casing changes	SubPUMP checks to see if the casing configuration has changed since the last pump selection. If so, then you may want to check your pump selection again to be sure it will still fitinside the casing.
Casing ID	.825 to 18.73 inches.
Casing OD	4.2 to 20.0 inches.
Casing Pressure	0.0 to 99999.0 psig
Casing Wt	0.0 to 133.0 pounds per foot (optional).
Choke ID	0.0 to 19.12 inches
CO2	0.0 to 100 mole %
Discharge coefficient	0.50 to 2.50
Flowing BHP	If IPR is PI type, range is 0.0 to Static BHP in 1.0 psig increments, otherwise range is 0.1 to Static BHP in 1.0 psig increments.
Flowline Pressure	0.0 to 99999.0 psig
Fluid level	0.0 to pump depth, ft
Fluid over pump	0.0 to pump depth, ft
Gas gravity	0.5 to 2
Gas Injection Depth	1.0 to 45000 feet. Note that this depth must be lower than the pump depth.
H2S	0.0 to 100 mole %
Max angle at Pump, degrees	89
N2	0.0 to 100 mole %
Oil gravity	5 to 60 degrees API
Pipe Distance	1.0 to 105600 feet.
Pipe ID	.50 to 24.00 inches.
Pipe Roughness	0.000000001 to 0.1 inches.
Pmpg WH Temp	60.0 to 600 degrees F. Wellhead temperature while the well is pumping.
Prod. GLR	0.0 to 100000 scf/bbl
Prod. GOR	0.0 to 100000 scf/bbl
Productivity Index	0.01 to 99999.9, stb/d/psi
Pump depth	0.0 to casing depth, ft

Table C.1 SubPUMP design limits (cont.)

Pump intake pressure	0.0 to 99999.0 psig
Separator Pressure	14.7 to 22000 psia
Separator Temp	32.0 to 500 F
Soln. GOR	0.0 to 1000000 scf/bbl
Solution GOR	1.0 to 100000
Static BH Temp	60.0 to 600 degrees F. The wellbore temperature at the top perforation depth.
Static BHP	Std Press to 99999.0 psig
Tbg Clearance	If the Casing ID is less than 9.625 inches, then no tubing string can have a clearnace less than 0.001 inches between the casing ID and tubing OD.
Tbg Roughness	0.000000001 to 0.1 inches.
TDH	0.0 to 99999.0 psig
Top Perforation	1.0 to 45000 feet. Maximum value cannot exceed the plug back TD or lower perf TD. Note that all calculations for the bottom hole flowing pressure are referenced to this depth.
Total Fluid rate	If IPR is PI type, range is 0.0 to 99999.0 blpd, otherwise range is 0.1 to 99999.0 blpd.
Total fluid rate	0.0 to 99999.0 stb/d
Tubing bottom	1.0 to 45000 feet. This value is optional but can be solved for in the design criteria but the tubing weight, OD, ID and roughness must be entered for the first tubing string. The tubing bottom of the subsequent string msut be greater than the bottom of the preceding tubing string bottom plus 1 foot. The bottom fo the last tubing string will be adjusted to the pump depth automatically.
Tubing ID	0.824 to Tubing OD – 0.2 or 9.063, whichever is less.
Tubing OD	1.05 to Casing ID - 0.001 inches or 9.625 inches, whichever is less.
Tubing Wt	0.0 to 53.5 pounds per foot.
Water Cut	0.0 to 100.0%
Water gravity	1.0 to 2.5
Water salinity	0.0 to 120000.0 ppm

Table C.2 Reda equipment limits

Pumping / Housing:	REDA 540 GN10000	REDA 540 GN5200	REDA 538 SN8500	REDA 562 HN21000	REDA 540 GN6200
Free Gas at Pump Intake (warning), %	> 10	> 10	> 10	> 10	> 30
Free Gas at Pump Intake (error), %	> 80	> 35	> 50	> 50	> 50
Average Fluid Viscosity through Pump, SSU	> 50	> 50	> 50	> 50	> 50
Pump Intake Pressure, atm	< 15	< 15	< 15	< 15	< 15
Fluid over Pump Intake, m	< 152	< 152	< 152	< 152	< 152
Standard Shaft Power, HP	> 637	> 313	> 306	> 584	> 419
High Strength Shaft Power, HP	> 1019	> 500	> 490	> 934	> 670
Standard Housing Burst, atm	> 340	> 344	> 344	> 204	> 340
High Strength Housing Burst, atm	> 408	> 413	> 413	> 245	> 408
Tubing Burst (weakest grade), atm	> 195	> 181	> 951	> 364	> 957
Tubing Burst (strongest grade), atm	> 624	> 581	> 963	> 727	> 1404
Motor / Seal Section:	REDA 562	REDA 456	REDA 562	REDA 562	REDA 562
Fluid Velocity across Motor, m/sec	< 0.305	< 0.305	< 0.305	< 0.305	< 0.305
Reservoir Temperature, °C	> 121	> 110	> 121	> 121	> 121
Motor Shaft Power, HP	> 750	> 250	> 613	> 688	> 838
Seal Sect. Standard Shaft Power, HP	> 637	> 531	> 520	> 584	> 711
Seal Sect. High Strength Shaft Power, HP	> 1019	> 849	> 832	> 934	> 1138
Seal Sect. Maximum Thrust Load, kg		> 5670.0	> 5556.6	> 6237.0	
Well Angle at Pump Intake, Deg	> 88.98	> 70.02	> 88.98	> 88.98	> 88.98
Fluid Temp. @ Pump Depth, °C	>= 148.9	>= 148.9	>= 148.9	>= 148.9	>= 148.9
Motor Temperature, °C	>= 204.4	>= 204.4	>= 204.4	>= 204.4	>= 204.4
Motor Skin Temp. Rise, °C	>= 38.9	>= 30.6	>= 38.9	>= 38.9	>= 38.9
Motor Voltage, Volts	>= 4160		>= 4160	>= 4160	>= 4160
Cable:	Redalead AWG 2, Flat, Stranded	Redalead AWG 4, Flat, Solid	Redalead AWG 2, Flat, Stranded	Redalead AWG 2, Round, Solid	Redalead AWG 2, Flat, Stranded
Startup Motor Voltage, Volts	< 1631	< 1096	< 1631	< 1705	< 1631
Motor Voltage, Volts	< 2936 > 3425	< 1973 > 2301	< 2936 > 3425	< 3069 > 3581	< 2936 > 3425
Surface Voltage,Volts,	> 4000	> 4000	> 4000	> 4000	> 4000
Motor Amperage, Amps	> 186	> 132	> 186	> 220	> 186
Conductor Temp. @ Design Freq., °C	> 232	> 232	> 232	> 204	> 232

APPENDIX D

COST ANALYSIS

Table D.1 Assumptions made for cost analysis

Assumptions	**Cost**
Oil Price, $/bbl	40
Electricity Cost, $/KWh	0,5
Personnel Cost, $/bbl	3
Maitenance Cost, $/bbl	5
Insurance, %	5
Tax, %	35

Table D.2 Income of Current Design for Y-2 Well

Year	Oil Production bpd	After Royalty bpd	Oil Price $/bbl	Income $/y	After Insurance $/y	After Tax Net Income $/y
2004						0
2005	2333	2041	40	34.061.800	32.358.710	21.033.162
2006	2179	1907	40	31.813.721	30.223.035	19.644.973
2007	2035	1781	40	29.714.016	28.228.315	18.348.405
2008	1901	1663	40	27.752.891	26.365.246	17.137.410
2009	1775	1553	40	25.921.200	24.625.140	16.006.341
2010	1658	1451	40	24.210.401	22.999.881	14.949.922
2011	1549	1355	40	22.612.514	21.481.888	13.963.227
2012	1447	1266	40	21.120.088	20.064.084	13.041.654
2013	1351	1182	40	19.726.162	18.739.854	12.180.905
2014	1262	1104	40	18.424.236	17.503.024	11.376.966
2015	1179	1031	40	17.208.236	16.347.824	10.626.086

Table D.3 Cost of Current Design for Y-2 Well

Year	Personnel $/y	Maintenance $/y	Energy $/y	Disbursement $/y	Net Cash Flow $/y
2004				709000	- 709.000
2005	2.554.635	4.257.725	1.284.000	8.096.360	12.936.802
2006	2.386.029	3.976.715	1.284.000	7.646.744	11.998.229
2007	2.228.551	3.714.252	1.284.000	7.226.803	11.121.602
2008	2.081.467	3.469.111	1.284.000	6.834.578	10.302.832
2009	1.944.090	3.240.150	1.284.000	6.468.240	9.538.101
2010	1.815.780	3.026.300	1.284.000	6.126.080	8.823.842
2011	1.695.939	2.826.564	1.284.000	5.806.503	8.156.725
2012	1.584.007	2.640.011	1.284.000	5.508.018	7.533.637
2013	1.479.462	2.465.770	1.284.000	5.229.232	6.951.673
2014	1.381.818	2.303.029	1.284.000	4.968.847	6.408.118
2015	1.290.618	2.151.030	1.284.000	4.725.647	5.900.439
				Total $	**98.962.998**

Table D.4 Income of Recommended Design for Y-2 Well

Year	Oil Production bpd	After Royalty bpd	Oil Price $/bbl	Income $/y	After Insurance $/y	After Tax Net Income $/y
2004						0
2005	2352	2058	40	34.339.200	32.622.240	21.204.456
2006	2197	1922	40	32.072.813	30.469.172	19.804.962
2007	2052	1795	40	29.956.007	28.458.207	18.497.834
2008	1916	1677	40	27.978.911	26.579.965	17.276.977
2009	1790	1566	40	26.132.303	24.825.687	16.136.697
2010	1672	1463	40	24.407.571	23.187.192	15.071.675
2011	1561	1366	40	22.796.671	21.656.837	14.076.944
2012	1458	1276	40	21.292.091	20.227.486	13.147.866
2013	1362	1192	40	19.886.813	18.892.472	12.280.107
2014	1272	1113	40	18.574.283	17.645.569	11.469.620
2015	1188	1040	40	17.348.380	16.480.961	10.712.625

Table D.5 Cost of Recommended Design for Y-2 Well

Year	Personnel $/y	Maintenance $/y	Energy $/y	Disbursement $/y	Net Cash Flow $/y
2004				627000	- 627.000
2005	2.575.440	4.292.400	1.284.000	8.151.840	13.052.616
2006	2.405.461	4.009.102	1.284.000	7.698.563	12.106.399
2007	2.246.701	3.744.501	1.284.000	7.275.201	11.222.633
2008	2.098.418	3.497.364	1.284.000	6.879.782	10.397.195
2009	1.959.923	3.266.538	1.284.000	6.510.461	9.626.236
2010	1.830.568	3.050.946	1.284.000	6.165.514	8.906.161
2011	1.709.750	2.849.584	1.284.000	5.843.334	8.233.610
2012	1.596.907	2.661.511	1.284.000	5.542.418	7.605.448
2013	1.491.511	2.485.852	1.284.000	5.261.363	7.018.744
2014	1.393.071	2.321.785	1.284.000	4.998.857	6.470.763
2015	1.301.129	2.168.548	1.284.000	4.753.676	5.958.949
				Total $	**99.971.755**